## 1-SEC-1

### Ref: Application, p. 7, Sch. D, s. 1.1(ttt)

Please provide a copy of the unanimous shareholders agreement referred to.

### Response

The reference to the unanimous shareholders agreement was specifically with respect to buy sell provisions which governed the obligations on both parties should a shareholder wish to sell their respective shares.

The buy sell sections from the unanimous shareholders agreement are excerpted below:

**ARTICLE 9**

**BUY-SELL PROVISIONS**

**9.1 Buy/Sell Notice.**

(a) Subject to paragraph (b), either of the Shareholders (the **"Offeror")** shall be entitled to give notice (the **"Buy/Sell Notice")** to the other Shareholder (the **"Offeree"),** which Buy/Sell Notice shall be signed by the Offeror and shall contain the following:

(i) the price at which the Offeror will purchase or sell each Share;

(ii) an unconditional offer, irrevocable without the written consent of the Offeree, to purchase all of common shares beneficially owned by the Offeree at the said prices and upon and subject to the terms set forth in the Buy/Sell Notice; and

(iii) an unconditional offer, irrevocable without the written consent of the Offeree, to sell all of the Shares beneficially owned by the Offeror at the said prices and upon and subject to the terms set forth in the Buy/Sell Notice.

(b) No Shareholder is entitled to exercise the rights provided for in paragraph (a) until the expiry of the Standstill Period.

**9.2 Acceptance.** The Offeree shall be entitled to accept either of the offers contained in the Buy/Sell Notice by notice in writing delivered to the Offeror within 20 days of receipt by the Offeree of the Buy/Sell Notice.

**9.3 Purchase and Sale.** If the Offeree accepts the offer referred to in Subsection 9.1(a)(ii), the Offeree shall sell to the Offeror and the Offeror shall purchase from the Offeree all of the Shares beneficially owned by the Offeror (the **"Offered Shares")** at the prices and, subject to the provisions of this Agreement, upon the terms set forth in the Buy/Sell

Notice. If the Offeree accepts the offer referred to in Subsection 9.1(a)(iii), the Offeree shall purchase from the Offeror and the Offeror shall sell to the Offeree all of the shares of the Corporation beneficially owned by the Offeror at the prices and, subject to the provisions of this agreement, upon the terms set forth in the Buy/Sell Notice. If the Offeree does not accept either of the said offers within the said 20 day period, the Offeree shall be deemed to have accepted the offer referred to in Subsection 9.1(a)(ii), on the last day of the said 20 day period and the Offeree shall sell to the Offeror and the Offeror shall purchase from the Offeree all of the Offered Shares beneficially owned by the Offeree at the prices set forth in the Buy/Sell Notice. Notwithstanding anything in the Buy/Sell Notice to the contrary, the aggregate purchase price for the Offered Shares shall be paid in full at the Time of Closing. The closing of a transaction of purchase and sale contemplated in this Article shall take place at the on the date (the **"Date of Closing")** which is 15 days following the acceptance by the Offeree of one of the offers contained in the Buy/Sell Notice. If, at the Time of Closing, a Shareholder (the **"Refusing Shareholder")** neglects or refuses to complete the transaction of purchase and sale herein contemplated, the other Shareholder (the **"Enforcing Shareholder")** shall have the right, without prejudice to any other rights which the Enforcing Shareholder may have, to give to the Refusing Shareholder, within five days of the Date of Closing, a notice that the Enforcing Shareholder intends to purchase from the Refusing Shareholder all of the Shares beneficially owned by the Refusing Shareholder at a purchase price for each share equal to 90% of the price for shares set forth in the Buy/Sell Notice (the **"New Purchase Price").** The resulting transaction of purchase and sale shall take place on the date (the **"New Date of Closing")** which is 15 days following the receipt or deemed receipt of the aforesaid notice. On the New Date of Closing, the Refusing Shareholder shall sell all of the Shares beneficially owned by it to the Enforcing Shareholder who shall purchase the same for the New Purchase Price, which shall be payable in accordance with the terms contained in this Article for the payment of the purchase price of the Offered Shares.

## 1-SEC-2

## Ref: p. 8

Please confirm that the last cost of service review of the distributor was in EB-2012-0116. Please provide the achieved ROE, calculated on a regulatory basis, for each year from 2013-2017, and file any forecasts of the Applicants that include ROE forecasts for 2018 and beyond.

## Response

The last cost of service review was EB-2012-0116. The archived ROE as it appears on Collus PowerStream Corp.'s scorecard has been reproduced below.

| Measures | | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| Profitability: Regulatory Return on Equity | Deemed (included in rates) | 8.01% | 8.98% | 8.98% | 8.98% | 8.98% |
| | Achieved | 0.10% | 8.40% | 11.21% | 10.86% | 10.03% |

The 2017 deemed ROE is 8.98% and the 2017 achieved ROE, as filed with the Board in Collus PowerStream Corp.'s April 30, 2018 RRR filing, is 11.65% and remains subject to the Board's review. The ROE forecast for 2018 and beyond approximates the OEB's most recently approved ROE.

## 1-SEC-3

## Ref: p. 8/9

Please confirm that, aside from any Transfer Tax or Departure Tax, the closing adjustments in the EPCOR Agreement are expected to be exactly double the closing adjustments in the Alectra Agreement.

## Response

We assume that both transactions, namely the Town of Collingwood's purchase of 50% of the issued and outstanding shares of Collingwood PowerStream Utility Services Corp. from Alectra Utilities Corporation and EPCOR Collingwood Distribution Corp.'s purchase all of the issued and outstanding shares of Collingwood PowerStream Utility Services Corp. from the Town of Collingwood, will close on the same day. Both the EPCOR Agreement and the Alectra Agreement contemplate the purchase price being subject to adjustments after closing of each transaction for working capital, net fixed assets, regulatory accounts and long term debt. The quantum of the closing adjustments are expected to be identical, the only difference being that under the Alectra Agreement, the Town of Collingwood will share closing adjustments with Alectra Utilities Corporation on a 50/50 basis.

**1-SEC-4**

**Ref: p. 9, 19**

Please advise whether the Applicants are seeking an amendment to the distribution licence for the name change in this Application, or in a separate application. Please confirm that the Applicants intend that the distribution licence not be transferred, and that the existing corporation will continue to carry on the distribution business. Please reconcile your response with the statement on page 19 that "EPCOR will carry on and continue the business of CollusLDC".

**Response**

EPCOR intends to seek an amendment to the name on the distribution licence to EPCOR Collingwood Local Distribution Corp. (EPCOR LDC). This name change will be sought in a separate process, subject to Board approval of the current Application. EPCOR understands that in order to obtain an amendment to the name on the distribution license the OEB requires a change of name certificate from the corporate registry. As EPCOR does not have the right to change the name of CollusLDC (Collus PowerStream Corp.) until after the transaction closes, it is unable to obtain a name change on the license until post close.

EPCOR intends that the distribution license will not be transferred and the existing corporation (under the new name of EPCOR Collingwood Local Distribution Corp. (EPCOR LDC)) will continue to carry on the distribution business. As a parent of EPCOR LDC, EPCOR (EPCOR Collingwood Distribution Corp.) will direct that EPCOR LDC carry on and continue the business of CollusLDC.

## 1-SEC-5

### Ref: p. 10, 13, 31

With respect to the Distribution System Plan:

a) Please confirm that the document entitled "Collus Powerstream Corp. 2018-2022 Distribution System Plan" dated March 15, 2017, and attached to these interrogatories, is the current Distribution System Plan of the distributor.

b) Please confirm that the Applicants advised the Board by letter dated February 9, 2018 that the DSP was "available for submission", but that it has not yet been filed with the Board.

c) If this document is the current DSP of the distributor, please file this document on the record in this proceeding. If it is not, please file the current DSP of the distributor.

d) Please advise the Applicants' proposal for the review of its DSP by the Board.

### Response

a) The current version of the DSP, dated April 24, 2018 is available on the Collus PowerStream website at: https://www.colluspowerstream.ca/DSP

b) The current version of the DSP is available for filing, however, Collus PowerStream Corp. has not been requested by the OEB to file its DSP.

c) The Collus PowersStream Board of Directors will be reviewing the current version of the DSP at the next Board meeting, anticipated to take place in June 2018, at which time the DSP is expected to be approved for submission to the OEB.

d) The DSP is expected to be filed with the OEB following the next meeting of the Collus PowerStream Board of Directors.

## 1-SEC-6

## Ref: p. 10

Please provide a detailed estimate, consistent with the DSP, of the expected ICM applications for each year 2019-2023. Please describe how each of the forecast ICM claims are consistent with the principles outlined by the Board in its Decision and Order dated April 5, 2018 in EB-2017-0024.

## Response

Please see the response to 1-Staff-14.

## 1-SEC-7

**Ref: p. 10**

Please provide an up-to-date continuity schedule showing the current balances of each of the regulatory asset and liability accounts, and reconcile those balances back to the most recent financial statements of the distributor.

## Response

The continuity schedule and reconciliation are attached as Appendix A hereto.

**1-SEC-8**

## Ref: p. 13

Please advise whether the Applicants agree that the obligation “to meet or exceed current reliability standards for the next five years” should be made a condition of the Board’s approval of the Applications.

## Response

The obligation to meet or exceed current reliability standards for the next five years should not be made a condition of the Board’s approval of the Applications. EPCOR recognizes and is supportive of the Board’s drive for operational efficiency as an outcome arising from The Renewed Regulatory Framework for Electricity and in particular the decision resulting from the Electricity Distribution System Reliability Measures and Expectations (EB-2014-0189). As detailed in section 10.2 of the Application, EPCOR affiliates have a strong history of meeting or exceeding the operational efficiency expectations of the regulators within whose jurisdiction it operates. However, directly tying EPCOR’s approval to operate CollusLDC to meeting these standards is, to EPCOR’s knowledge, a more onerous condition than that which any other LDC within Ontario operates. This would also be over and above conditions included in the Distribution System Code. Given the evidence that this condition is not necessary, inconsistent with other similar approvals, and subject to different interpretations, making compliance and enforcement challenging, imposing this condition would be unreasonable and therefore not a condition that the approval should be tied to.

**1-SEC-9**

**Ref: p. 31**

Please provide a breakdown of each of the Status Quo and EPCOR forecasts of OM&A for the years 2019-2024, showing in particular the sources of the proposed cost efficiencies as outlined in the evidence.

## Response

Please see EPCOR's response to 1-Staff-1.

## 1-SEC-10

## Ref: p. 31

Please explain why no cost efficiencies are expected in capital spending. In particular, please explain whether any of the OM&A efficiencies will include expenditures that are currently capitalized in part, and whether any of the General Plant expenditures in the DSP can be avoided if the transactions are approved by the Board.

## Response

EPCOR's assessment is that the capital plans described in the DSP are reasonable.

None of the OM&A efficiencies identified include expenditures that are currently capitalized in part.

## 1-SEC-11

## Ref: p. 31

Please explain why the 1% negative rate rider is only proposed for residential customers.

## Response

The 1% negative rate rider that is proposed for residential customers is the result of a commercial negotiation between EPCOR and the Town.

## 1-SEC-12

## Ref: Sch. A, Sch. E, s. 1.1(i)(iii)

Please confirm that Collus Solutions Corp. provided services to the distributor and to the Town of Collingwood until December 31, 2016, and that service business was terminated January 1, 2017. If confirmed, please reconcile that response with the definition in the Agreement. Please advise what impacts, if any, were experienced by the distributor as a result of this change.

## Response

On January 1, 2017, Collus PowerStream Solutions Corp. became inactive. All employees of Collus PowerStream Solutions Corp. were transferred to Collus PowerStream Corp. on or before January 1, 2017.

Collus PowerStream Solutions Corp. provided (i) building and property maintenance; (ii) geographic information system support; (iii) human resources services; (iv) accounting services; and (v) management services to Collus PowerStream Corp. and the Town of Collingwood from April 13, 2000, to December 31, 2015, after which time all such services were terminated by the Town of Collingwood. The staff were reallocated to Collus PowerStream Corp. and the staff continue to perform the same work but for the LDC only. Collus PowerStream Corp. mitigated the loss of these shared services by not replacing two staff who departed the organization in 2016.

Collus PowerStream Solutions Corp. provided (i) billing, collecting, and customer service and (ii) information technology services to Collus PowerStream Corp. prior to December 31, 2016. As of January 1, 2017, these services have been and continue to be performed by Collus PowerStream Corp.

Collus PowerStream Solutions Corp. provided billing, collecting and customer service to the Town of Collingwood from April 13, 2000, to December 31, 2016. Collus PowerStream Corp. has continued to provide these services to the Town of Collingwood since January 1, 2017. The parties are currently in the process of negotiating an updated, written agreement. To date, both the provision of these services by Collus PowerStream Corp. and payment for such services by the Town of Collingwood have been completed in a timely manner.

In addition, Collus PowerStream Solutions Corp. provided information technology (“IT”) services to the Town of Collingwood from April 13, 2000 to December 31, 2016, and Collus PowerStream Corp. provided IT services to the Town of Collingwood from January 1, 2017 to June 30, 2017. On December 14, 2016, Town Council decided to assume its own IT systems by June 30, 2017. On January 30, 2017, Collus PowerStream Corp. gave notice to the Town of Collingwood to terminate the IT support arrangement and, on June 30, 2017, Collus PowerStream Corp. staff ceased providing IT services to the Town of Collingwood. Collus PowerStream Corp. has seen an increase of approximately $150,000 in IT expenses as a result of the termination of the IT support arrangement.

## 1-SEC-13

## Ref: Sch. C, p. 4

With respect to corporate governance of the distributor post-closing;

a) Please provide a list of the current directors of EUI.

b) Please confirm that EUI will be appointing directors for each of EPCOR Ontario, CollusHoldco, and CollusLDC, and that none of the current directors of the distributor, who are resigning on closing, will be retained.

c) Please advise how many directors will be appointed at each level.

d) Please advise how many of those directors at each level will be independent of EUI.

e) Please advise how many of those directors at each level will be based in Ontario.

f) Please advise at which corporate level (EUI, EPCOR Ontario, CollusHoldco, or CollusLDC) the major decisions affecting the distributor will be made and ultimately approved. If there will be different responsibilities for different types or categories of decisions, please provide a full description of how decisions relating to distribution will be made and approved after closing.

g) Please provide details on how, if at all, the planned governance of the distributor will be consistent with, or not consistent with, the guidance of the Board proposed in the draft Report of the Board in EB-2014-0255 dated March 28, 2018.

## Response

a) The current Directors of EUI are:

Janice Rennie (Chair)
Sheila Weatherill (Vice Chair)
Rick Cruickshank
Vito Culmone
Robert G. Foster
David Day
Alan Krause
Allister J. McPherson
Catherine M. Roozen
Helen Sinclair
Nizar Somji

b) EPCOR notes that, as per schedule B of the Application, EPCOR Ontario is an existing corporation that is not involved in the governance of CollusHoldco and not an entity subject to EPCOR's MAAD application. EPCOR assumes that the SEC intended to request information regarding EPCOR Holdings East Inc., which is the holding company through which EPCOR will report, and is responding as such. EPCOR intends to appoint directors for each of the referenced companies, noting that in the case of EPCOR Holdings East Inc. and CollusHoldco, such appointments will be undertaken with a focus on meeting requirements of corporate law.

EPCOR Holdings East Inc. is and, once acquired, Collus Holdco will be intermediate holding companies between EPCOR LDC and EUI. EPCOR's current practice with respect to holding companies is to utilize unanimous shareholder agreements to draw up the powers of the directors of such holding companies to EUI. This practice is separate from that intended for EPCOR LDC which is not expected to have a unanimous shareholder agreement with any of its affiliates. The practice of not implementing unanimous shareholders agreements for entities which are regulated by the OEB was also implemented in EUI's recent acquisition of the assets of Natural Resource Gas Limited.

It is confirmed that none of the current directors of the distributor will be retained.

c) For EPCOR Holdings East Inc. and, Collus Holdco, once acquired, it is intended that two directors will be appointed. In addition, please see the response to sub-question (b) above.

With respect to EPCOR LDC, EPCOR will establish a board and governance structure which is consistent with applicable requirements, including the Affiliate Relationship Code and the Ontario Energy Board Act. The current intent is to appoint three directors of which one will be independent.

d) With respect to EPCOR Holdings East Inc. and CollusHoldco, this is not applicable / relevant given the response to sub-question (b) above.

With respect to CollusLDC, please see the response to c) above.

e) The non-independent board members are not expected to be based in Ontario. EPCOR's preference for the independent board member is that they be based in Ontario and EPCOR is presently reviewing experienced candidates who are based in Ontario. As an example, the independent board member for EPCOR Ontario Utilities Inc. (the general partner of EPCOR Natural Gas Limited Partnership) is based in Ontario. The chief executive officer of EPCOR LDC will be based in Ontario.

f) It is intended that major decisions affecting the distributor will be approved at the EPCOR LDC. level, with general oversight and guidance provided from the parent level, as is customary. At the EPCOR LDC level, the directors will have the rights and responsibilities typical of the board of a corporation. This includes approval of budgets, strategic plans, financing and other matters typically within the preview of a board.

EPCOR advises that it is currently reviewing a corporate governance structure for its Ontario businesses in light of having recently acquired the assets of Natural Gas Resources Ltd. and having been successful in the competitive proceeding related to the CPCN for Southern Bruce gas utilities as well as recent and pending developments within the Ontario regulatory framework with respect to corporate governance.

g) For the following areas under which the OEB provided guidance, EPCOR provides the following details as to the governance of EPCOR LDC

Director Independence

A. Independence – EPCOR LDC is expected to have one of three directors as independent
B. Board Size – EPCOR LDC is expected to have three directors
C. Scope of Oversight – EPCOR LDC. is not expected to have a shareholder agreement that limits the board of directors from exercising its independent judgement

Director Skills

- EUI will appoint experienced executives as board members and the board will have the complete range of skills necessary to execute its governance functions and discharge its responsibilities effectively.

Board and Committee Structures and Functions

- EUI is of the view that for an entity the size and magnitude of EPCOR LDC the board as a whole will most effectively bring its requisite skills to discharge its responsibilities.

Supporting Documentation and Practices

- The board for EPCOR LDC will have a documentation detailing mandate, code of business conduct and new appointees will be provided with an orientation.

Reporting and Record-Keeping Requirements

- EPCOR LDC will be compliant will all reporting and record-keeping requirements as required by the OEB.

## 1-SEC-14

### Ref: Sch. E, s. 1.1(z)

Please provide a copy of the Confidentiality Agreement referred to.

### Response

The Applicants refuse to produce the Confidentiality Agreement given it is not relevant to the matters considered by the Board in a MAAD application process.

## 1-SEC-15

## Ref: Sch. E, s. 2.6(a) and Art. X

Please confirm that the Applicants do not expect any Departure Tax or Transfer Tax to be payable in respect of the proposed transactions. If not confirmed, please estimate the amount of any such tax if material.

## Response

Confirmed. EPCOR does not expect any Departure or Transfer Tax to be payable in respect of the proposed transactions.

Because Collus PowerStream Corp. has fewer than 30,000 customers and the MAAD application has been submitted to the OEB prior to January 1, 2019, no Transfer Tax should apply.

EPCOR Collingwood Distribution Corporation is a municipally owned corporation under Section 149(1.2)(b)(ii) of the Income Tax Act. As a tax-exempt entity no Departure Tax would apply.

**1-SEC-16**

## Ref: Sch. E., s. 6.8, DSP p. 72

Please reconcile the provision in the Agreement ($2 million capex per year) with the forecast capital spending in the DSP. If the DSP is not the “current capital plan”, please provide the current capital plan of the distributor.

## Response

EPCOR views the $2 million average annual capital expenditure to be a general undertaking within the share purchase agreement between the Town of Collingwood and EPCOR dated November 30, 2017 that EPCOR will continue to invest in the utility as necessary. The current capital plan is the DSP.

**1-SEC-17**

**Ref: Sch. E, s. 7.2**

Please confirm that the role of the Vendor as nominee and bare trustee is intended to ensure that the Applicants can continue to benefit from Infrastructure Ontario funding despite no longer being controlled in Ontario.

**Response**

On closing, the obligations relating to the Infrastructure Funding will be assigned and transferred by the LDC to the Town of Collingwood and the LDC will concurrently enter into a loan agreement with the Town of Collingwood that contains substantially similar terms as the existing loan agreements with respect to the Infrastructure Funding. Infrastructure Ontario and Lands Corporation has consented to the assignment and transfer of the obligations relating to Infrastructure Funding by the LDC to the Town of Collingwood. The nominee and bare trustee relationship in the share purchase agreement is a contractual acknowledgement between the Vendor and the Purchaser that reflects that the Infrastructure Funding will continue to be an obligation of the LDC.

## 1-SEC-18

## Ref: Sch. G

Please provide the December 31, 2017 audited financials of Collus Powerstream Corp.

## Response

The December 31, 2017 audited financials of Collus PowerStream Corp. are attached as Appendix B hereto.

## 1-SEC-19

## Ref: Sch. H

Please provide the December 31, 2017 audited financials of EPCOR Utilities Inc.

## Response

The December 31, 2017 audited financials of EPCOR Utilities Inc. are attached as Appendix C hereto.

## 1-SEC-20

## Ref: Sch. G, p. 12, Sch. H, p. 10

Please advise whether the capitalization and depreciation accounting policies of the distributor are consistent with those of the Purchaser, including but not limited to the useful lives being applied. Please advise whether any changes to accounting policies will occur after the closing date. If the answer is yes (or maybe), please describe the Applicants' proposal for how to ensure that the customers are not subjected to any double-recovery of amounts in rates due to accounting changes.

## Response

The capitalization and depreciation policies are consistent between the distributor and the purchaser and are both consistent with and both comply with proper accounting under International Financial Reporting Standards (IFRS).

As the existing policies and useful lives have been approved by Board there would not be any change in useful lives of the existing asset categories or accounting policies as approved by the Board in the current application period.

## 1-SEC-21

## Ref: Sch. G, p. 25

Please provide the accounting order of the Board approving the deferral account for the Sensus ICON meters.

## Response

The accounting order approving the deferral account for the Sensus ICON meters is attached as Appendix D hereto.

**1-SEC-22**

**Ref: DSP**

With respect to the DSP:

a) Please provide a table showing capital spending by category (with as much detail as possible) for 2013-2017, and forecast for 2018-2022.

b) Please confirm that the DSP proposes significantly higher capital spending in the future compared to the average for 2013-2017.

c) For each of the categories of spending in which a significant increase in capital spending is being proposed, please provide an explanation for the increase.

d) Please advise what involvement, if any, the Purchaser had in the development of the DSP.

## Response

a) The current version of the DSP dated April 24, 2018 is available on the Collus PowerStream website at: https://www.colluspowerstream.ca/DSP

The table on the following page shows capital spending by category for the period from 2013-2017 and forecast spending by category for the period from 2018-2022, as presented at page 97 of the DSP.

| Category | Historical (previous plan and actual) | | | | | | | | | | | | | | | Forecast (Planned) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2013(CGAAP) | | | 2014(CGAAP) | | | 2015(IFRS) | | | 2016(IFRS) | | | 2017(IFRS) | | | 2018 | 2019 | 2020 | 2021 | 2022 |
| | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | Plan | Actual | Var | | | | | |
| | $'000 | $'000 | % | $'000 | $'000 | % | $'000 | $'000 | % | $'000 | $'000 | % | $'000 | $'000 | % | $'000 | $'000 | $'000 | $'000 | $'000 |
| System Access | | 192 | | | 421 | | | 561 | | 319 | 259 | | 303 | 421 | | 581 | 312 | 318 | 324 | 330 |
| System Renewal | | 645 | | | 482 | | | 623 | | 1558 | 1116 | | 2116 | 2118 | | 1895 | 2528 | 2283 | 2339 | 2562 |
| System Service | | 42 | | | 512 | | | 395 | | 1015 | 697 | | 51 | 36 | | 51 | 52 | 53 | 54 | 55 |
| General Plant | | 238 | | | 387 | | | 131 | | 621 | 508 | | 626 | 459 | | 652 | 365 | 658 | 586 | 299 |
| Total | | 1117 | | | 1802 | | | 1710 | | 3513 | 2580 | | 3096 | 3035 | | 3180 | 3256 | 3312 | 3303 | 3246 |
| System O&M | | 2053 | | | 2169 | | | 2389 | | 2298 | 2482 | | 2517 | 2190 | | 2651 | 2645 | 2711 | 2856 | 2848 |

## Explanatory Notes on Variances

**Notes on shifts in forecast vs. historical budgets by category**

Not applicable- no previous DSP filed

**Notes on year over year Plan vs. Actual variances for Total Expenditures**

Not applicable- no previous DSP filed – 2016 actual as of September 30

**Notes on Plan vs. Actual variance trends for individual expenditure categories**

Not applicable- no previous DSP filed.

**Capital Expenditure Summary**

The tables below summarize the proposed capital investments (annual $ and % spend) within the four designated investment categories for the period from 2018-2022, as presented at page 11 of the DSP.

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| System Access | $ 581,270 | $ 311,956 | $ 317,884 | $ 323,923 | $ 330,078 |
| System Renewal | $ 1,895,340 | $ 2,527,530 | $ 2,283,120 | $ 2,339,224 | $ 2,562,300 |
| System Services | $ 51,087 | $ 52,058 | $ 53,047 | $ 54,055 | $ 55,082 |
| General Plant | $ 651,930 | $ 364,816 | $ 657,757 | $ 585,755 | $ 298,809 |
| Total | $ 3,179,627 | $ 3,256,361 | $ 3,311,809 | $ 3,302,958 | $ 3,246,270 |

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| System Access | 18% | 10% | 10% | 10% | 10% |
| System Renewal | 60% | 78% | 69% | 71% | 79% |
| System Services | 2% | 2% | 2% | 2% | 2% |
| General Plant | 21% | 11% | 20% | 18% | 9% |
| Total | 100% | 100% | 100% | 100% | 100% |

**CPC Capital Investment Summary 2018 - 2022**

A comparative analysis of spending by category for the period from 2013-2017 is available at page 98 of the DSP. A detailed description of historical spending by category and for individual projects for the period from 2013-2017 is provided at pages 99-102 of the DSP.

Pages 111-176 of the DSP provide details of the proposed individual projects for the period from 2018-2022. Page 197 shows Capital by G/L for the period from 2018-2022, as presented at page 197 of the DSP.

b) The chart below shows actual capital additions contributions form 2013-2017 and budgeted capital additions contributions for 2018-2022. The average difference between the actual 2013-2017 contributions and budgeted 2018-2022 contributions is $1,215,437.

**ACTUAL**

| | 2013 | 2014 | 2015 | 2016 | 2017 | Total | Average |
|---|---|---|---|---|---|---|---|
| Capital Additions | 1,439,877 | 2,142,439 | 2,443,137 | 4,319,099 | 3,562,748 | 13,907,300 | 2,781,460 |
| Contributions | (323,111) | (351,231) | (745,573) | (1,739,589) | (527,957) | (3,687,461) | (737,492) |
| | 1,116,766 | 1,791,208 | 1,697,564 | 2,579,510 | 3,034,791 | 10,219,839 | 2,043,968 |

**BUDGET**

| | 2018 | 2019 | 2020 | 2021 | 2022 | Total | Average |
|---|---|---|---|---|---|---|---|
| Capital Additions | 3,638,050 | 3,723,494 | 3,787,818 | 3,788,010 | 3,740,538 | 18,677,910 | 3,735,582 |
| Contributions | (458,423) | (467,133) | (476,009) | (485,052) | (494,268) | (2,380,885) | (476,177) |
| | 3,179,627 | 3,256,361 | 3,311,809 | 3,302,958 | 3,246,270 | 16,297,025 | 3,259,405 |

| Avg Difference |
|---|
| 1,215,437 |

c) Collus PowerStream's "System Access" investments are driven by others. Collus PowerStream is obligated to connect new load and new renewable generation (mandatory tasks). The scheduling of investments needs is usually coordinated to meet the needs of third parties. Average annual spending is generally in line with average historical annual expenditure.

Overall capital expenditures and specifically "System Renewal" investments were reduced in the 2013-2015 period in part due to labour resource constraints. Existing labour resources were focused on addressing annual O&M needs, mandatory "System Access" needs and priority "System Service" needs. As such, a number of "System Renewal" projects were deferred to future years. These issues were resolved by 2016 and Collus PowerStream was able to focus more effort on System Renewal program needs to address pole and UG cable plant at end-of life status. Additional increased cost factors, as a result of lessons learned from the 2013 ice storm, include design standards changes to improve the reliability and resiliency of distribution plant in response to adverse weather situation (i.e. utilization of Class 2 poles in place of Class 3 poles for "System Renewal" needs rather than like for like replacement).
"System Service" needs are reduced in the forecast period. Historical expenditures were dominated by DS station upgrade costs and a couple of line extension projects. Forecast needs are limited to SCADA enhancement costs.
"General Plant" needs are dominated by fleet replacement expenditures in the forecast period and are expected be higher than historical average spends due to vehicle type, cost (i.e. impact on vehicle price due to drop in CDN/US exchange value) and delivery timing. Other "General Plant" historical/forecast expenditures will vary by category but on average will have similar five year spends except for computer hardware and software areas expenditures that are expected to be higher than historical levels due to continuing need to upgrade systems to meet vendor version support requirements and user functionality needs.

d) The DSP was prepared directly by Collus PowerStream staff and consultants with no involvement from EPCOR.

**1-SEC-23**

**Ref: General**

Attached to these interrogatories is a copy of an article dated February 27, 2018 at the CBC News website describing a judicial inquiry into the sale of 50% of the distributor to Powerstream. Please describe the status of this inquiry, and the implications of this inquiry, if any, on the proposed transactions.

**Response**

The Town of Collingwood has requested that a judge of the Ontario Superior Court of Justice inquire into the sale of 50% of the distributor to PowerStream in 2012. The Town awaits direction from the office of the Ontario Superior Court of Justice on next steps. The judicial enquiry has no implications on the proposed transactions given that the focus on the review is restricted to the 2012 transaction.

## 1-SEC-24

## Ref: General

Attached to these interrogatories is a news release dated February 21, 2018 on the Town of Collingwood website describing a material billing problem between the distributor and the Town. Please describe the status of this matter, and any implications on the proposed transactions.

## Response

As the news release indicates, recently the Town was advised that it had been overcharged by Collus PowerStream for electricity for many years. To date, the Town has received a refund from Collus PowerStream in the amount of $410,747.42. The Town continues to consider its options for the recovery of further amounts but no decision has been made by Council at this time other than to request that Measurement Canada investigate the billing error. At this time Collus' overcharging error is not expected to have material implications on the proposed transactions given the matter involves only Collus and its customer, the Town of Collingwood.

# APPENDIX A:
# Continuity Schedule

***COLLUS PowerStream Corp***
***OEB QUARTERLY DEFERRAL ACCOUNT REPORTING***
***For the Twelve Months Ending Sunday, December 31, 2017***

| | | Opening | January | February | March | Quarter 1 | Balance | April | May | June | Quarter 2 | Balance | July | August | September | Quarter 3 | Balance | October | November | December | Quarter 4 | Balance | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***DEFERRAL ACCOUNTS*** | | | | | | | | | | | | | | | | | | | | | | | |
| Other Reg Assets - Icon F&G Meter Disposal | 1508-0005-00 | $512,493.00 | | | | | $512,493.00 | | | | | $512,493.00 | | | | | $512,493.00 | | | | | $512,493.00 | |
| Carrrying Charges - Icon F&G Meter Disposal | 1508-0005-01 | 15,098.80 | 478.79 | 432.46 | 478.79 | 1,390.04 | 16,488.84 | 463.35 | 478.79 | 463.35 | 1,405.49 | 17,894.33 | 478.79 | 478.79 | 463.35 | 1,420.93 | 19,315.26 | 652.90 | 631.84 | 652.90 | 1,937.64 | 21,252.90 | |
| | | 527,591.80 | 478.79 | 432.46 | 478.79 | 1,390.04 | 528,981.84 | 463.35 | 478.79 | 463.35 | 1,405.49 | 530,387.33 | 478.79 | 478.79 | 463.35 | 1,420.93 | 531,808.26 | 652.90 | 631.84 | 652.90 | 1,937.64 | 533,745.90 | |
| Other Regulatory Assets - OEB Cost Assessment Variance | 1508-0007-00 | 27,693.00 | 9,577.00 | | | 9,577.00 | 37,270.00 | 9,659.00 | | | 9,659.00 | 46,929.00 | 9,659.00 | | | 9,659.00 | 56,588.00 | 9,827.00 | | | 9,827.00 | 66,415.00 | |
| Carrrying Charges - OEB Cost Assessment Variance | 1508-0007-01 | 124.42 | 25.87 | 31.45 | 34.82 | 92.14 | 216.56 | 33.70 | 43.84 | 42.43 | 119.97 | 336.53 | 43.84 | 52.87 | 51.16 | 147.87 | 484.40 | 72.09 | 81.88 | 84.61 | 238.58 | 722.98 | |
| | | 27,817.42 | 9,602.87 | 31.45 | 34.82 | 9,669.14 | 37,486.56 | 9,692.70 | 43.84 | 42.43 | 9,778.97 | 47,265.53 | 9,702.84 | 52.87 | 51.16 | 9,806.87 | 57,072.40 | 9,899.09 | 81.88 | 84.61 | 10,065.58 | 67,137.98 | |
| Other Reg Assets - Energy East Consultation Costs | 1508-0006-00 | 2,274.98 | | | | | 2,274.98 | | | | | 2,274.98 | | | | | 2,274.98 | | | | | 2,274.98 | |
| Carrying Charges - Energy East Consultation Costs | 1508-0006-01 | 40.24 | 2.13 | 1.92 | 2.13 | 6.18 | 46.42 | 2.06 | 2.13 | 2.06 | 6.25 | 52.67 | 2.13 | 2.13 | 2.06 | 6.32 | 58.99 | 2.90 | 2.80 | 2.90 | 8.60 | 67.59 | |
| | | 2,315.22 | 2.13 | 1.92 | 2.13 | 6.18 | 2,321.40 | 2.06 | 2.13 | 2.06 | 6.25 | 2,327.65 | 2.13 | 2.13 | 2.06 | 6.32 | 2,333.97 | 2.90 | 2.80 | 2.90 | 8.60 | 2,342.57 | |
| Regulatory Asset IFRS | 1508-0002-00 | 189,206.17 | | | | | 189,206.17 | | | | | 189,206.17 | | | | | 189,206.17 | | | | | 189,206.17 | |
| IFRS Carrying Charges | 1508-0002-01 | 12,079.77 | 176.77 | 159.66 | 176.77 | 513.20 | 12,592.97 | 171.06 | 176.77 | 171.06 | 518.89 | 13,111.86 | 176.77 | 176.77 | 171.06 | 524.60 | 13,636.46 | 241.04 | 233.27 | 241.04 | 715.35 | 14,351.81 | |
| | | 201,285.94 | 176.77 | 159.66 | 176.77 | 513.20 | 201,799.14 | 171.06 | 176.77 | 171.06 | 518.89 | 202,318.03 | 176.77 | 176.77 | 171.06 | 524.60 | 202,842.63 | 241.04 | 233.27 | 241.04 | 715.35 | 203,557.98 | |
| Ontario Clean Energy Benefit | 1508-0003-00 | | | | | | | | | | | | 301.69 | | | 301.69 | 301.69 | | | -301.69 | -301.69 | | |
| | | | | | | | | | | | | | 301.69 | | | 301.69 | 301.69 | | | -301.69 | -301.69 | | |
| LPP Variance | 1508-0004-00 | -2,217.37 | | | | | -2,217.37 | | | | | -2,217.37 | | | | | -2,217.37 | | | | | -2,217.37 | |
| | | -2,217.37 | | | | | -2,217.37 | | | | | -2,217.37 | | | | | -2,217.37 | | | | | -2,217.37 | |
| Total Other Regulatory Assets | | 729,449.78 | 9,577.00 | | | 9,577.00 | 739,026.78 | 9,659.00 | | | 9,659.00 | 748,685.78 | 9,960.69 | | | 9,960.69 | 758,646.47 | 9,827.00 | | -301.69 | 9,525.31 | 768,171.78 | |
| Total Carrying Charges - Other Regulatory Assets | | 27,343.23 | 683.56 | 625.49 | 692.51 | 2,001.56 | 29,344.79 | 670.17 | 701.53 | 678.90 | 2,050.60 | 31,395.39 | 701.53 | 710.56 | 687.63 | 2,099.72 | 33,495.11 | 968.93 | 949.79 | 981.45 | 2,900.17 | 36,395.28 | |
| | | 756,793.01 | 10,260.56 | 625.49 | 692.51 | 11,578.56 | 768,371.57 | 10,329.17 | 701.53 | 678.90 | 11,709.60 | 780,081.17 | 10,662.22 | 710.56 | 687.63 | 12,060.41 | 792,141.58 | 10,795.93 | 949.79 | 679.76 | 12,425.48 | 804,567.06 | |
| Misc Deferred Debits - Regulatory Expenses (COS) | 1525-0000-00 | 57,999.15 | -6,855.00 | -3,105.00 | -5,855.00 | -15,815.00 | 42,184.15 | -6,855.00 | -4,750.00 | -6,000.00 | -17,605.00 | 24,579.15 | -5,000.00 | -5,000.00 | -6,000.00 | -16,000.00 | 8,579.15 | -4,140.00 | -4,053.37 | -385.78 | -8,579.15 | | |
| Deferred Charges Expansion | 1525-0002-00 | 57,065.00 | -680.00 | -680.00 | -680.00 | -2,040.00 | 55,025.00 | -680.00 | -680.00 | -680.00 | -2,040.00 | 52,985.00 | -680.00 | -680.00 | -680.00 | -2,040.00 | 50,945.00 | -680.00 | -680.00 | -680.00 | -2,040.00 | 48,905.00 | |
| | | 115,064.15 | -7,535.00 | -3,785.00 | -6,535.00 | -17,855.00 | 97,209.15 | -7,535.00 | -5,430.00 | -6,680.00 | -19,645.00 | 77,564.15 | -5,680.00 | -5,680.00 | -6,680.00 | -18,040.00 | 59,524.15 | -4,820.00 | -4,733.37 | -1,065.78 | -10,619.15 | 48,905.00 | |
| Renewable Connection Capital Deferral Acct | 1531-0000-00 | 1,268.78 | | | | | 1,268.78 | | | | | 1,268.78 | | | | | 1,268.78 | | | | | 1,268.78 | |
| Renewable Generation Carrying Charges | 1531-0000-01 | 113.69 | 1.19 | 1.07 | 1.19 | 3.45 | 117.14 | 1.15 | 1.19 | 1.15 | 3.49 | 120.63 | 1.19 | 1.19 | 1.15 | 3.53 | 124.16 | 1.62 | 1.56 | 1.62 | 4.80 | 128.96 | |
| | | 1,382.47 | 1.19 | 1.07 | 1.19 | 3.45 | 1,385.92 | 1.15 | 1.19 | 1.15 | 3.49 | 1,389.41 | 1.19 | 1.19 | 1.15 | 3.53 | 1,392.94 | 1.62 | 1.56 | 1.62 | 4.80 | 1,397.74 | |
| Renewable Connection OM&A Deferral Acct | 1532-0000-00 | 7,234.80 | 294.60 | 294.60 | 294.60 | 883.80 | 8,118.60 | 294.60 | 294.60 | 294.60 | 883.80 | 9,002.40 | 294.60 | 303.80 | 354.40 | 952.80 | 9,955.20 | 372.80 | 382.00 | 386.60 | 1,141.40 | 11,096.60 | |
| Renewable Connection OM&A Carrying Charges | 1532-0000-01 | 94.20 | 6.76 | 6.35 | 7.31 | 20.42 | 114.62 | 7.34 | 7.86 | 7.87 | 23.07 | 137.69 | 8.41 | 8.69 | 8.68 | 25.78 | 163.47 | 12.68 | 12.73 | 13.64 | 39.05 | 202.52 | |
| | | 7,329.00 | 301.36 | 300.95 | 301.91 | 904.22 | 8,233.22 | 301.94 | 302.46 | 302.47 | 906.87 | 9,140.09 | 303.01 | 312.49 | 363.08 | 978.58 | 10,118.67 | 385.48 | 394.73 | 400.24 | 1,180.45 | 11,299.12 | |
| Smart Grid Capital Deferral Acct | 1534-0000-00 | 4,500.00 | | | | | 4,500.00 | | | | | 4,500.00 | | | | | 4,500.00 | | | | | 4,500.00 | |
| Smart Grid Capital Carrying Charges | 1534-0000-01 | 210.91 | 4.20 | 3.80 | 4.20 | 12.20 | 223.11 | 4.07 | 4.20 | 4.07 | 12.34 | 235.45 | 4.20 | 4.20 | 4.07 | 12.47 | 247.92 | 5.73 | 5.55 | 5.73 | 17.01 | 264.93 | |
| | | 4,710.91 | 4.20 | 3.80 | 4.20 | 12.20 | 4,723.11 | 4.07 | 4.20 | 4.07 | 12.34 | 4,735.45 | 4.20 | 4.20 | 4.07 | 12.47 | 4,747.92 | 5.73 | 5.55 | 5.73 | 17.01 | 4,764.93 | |
| Smart Grid OM&A Deferral Acct | 1535-0000-00 | | | | | | | | | | | | | | | | | | | | | | |
| Smart Grid OM&A Carrying Charges | 1535-0000-01 | | | | | | | | | | | | | | | | | | | | | | |
| Meter Cost Deferral - Capital MIST >50 Interval | 1557-0000-00 | | | | | | | | 14,520.00 | 14,655.00 | 29,175.00 | 29,175.00 | | 61,843.32 | 1,805.02 | 63,648.34 | 92,823.34 | 266.07 | 521.29 | | 787.36 | 93,610.70 | This balanc |
| Meter Cost Deferral - Capital Carrying Charges | 1557-0000-01 | | | | | | | | | 13.13 | 13.13 | 13.13 | 27.26 | 27.26 | 82.29 | 136.81 | 149.94 | 118.25 | 114.77 | 119.26 | 352.28 | 502.22 | So there is |
| | | | | | | | | | 14,520.00 | 14,668.13 | 29,188.13 | 29,188.13 | 27.26 | 61,870.58 | 1,887.31 | 63,785.15 | 92,973.28 | 384.32 | 636.06 | 119.26 | 1,139.64 | 94,112.92 | |
| Meter Cost Deferral - Operations MIST >50 Interval | 1557-0001-00 | | | | | | | | | | | | | | | | | | 870.25 | 533.03 | 1,403.28 | 1,403.28 | |
| Meter Cost Deferral - Operations Carrying Charges | 1557-0001-01 | | | | | | | | | | | | | | | | | | | 1.11 | 1.11 | 1.11 | |
| | | | | | | | | | | | | | | | | | | | 870.25 | 534.14 | 1,404.39 | 1,404.39 | |
| Stranded Meter Costs | 1555-0003-00 | 469,326.00 | | | | | 469,326.00 | | | | | 469,326.00 | | | | | 469,326.00 | | | | | 469,326.00 | |
| Stranded Meter Rate Rider | 1555-0003-02 | -465,676.12 | | | | | -465,676.12 | | | | | -465,676.12 | | | | | -465,676.12 | | | | | -465,676.12 | |
| | | 3,649.88 | | | | | 3,649.88 | | | | | 3,649.88 | | | | | 3,649.88 | | | | | 3,649.88 | |
| Stranded Meter Costs - Carrying Charges | 1555-0003-01 | 6,241.46 | 3.41 | 3.08 | 3.41 | 9.90 | 6,251.36 | 3.30 | 3.41 | 3.30 | 10.01 | 6,261.37 | 3.41 | 3.41 | 3.30 | 10.12 | 6,271.49 | 4.65 | 4.50 | 4.65 | 13.80 | 6,285.29 | |
| | | 9,891.34 | 3.41 | 3.08 | 3.41 | 9.90 | 9,901.24 | 3.30 | 3.41 | 3.30 | 10.01 | 9,911.25 | 3.41 | 3.41 | 3.30 | 10.12 | 9,921.37 | 4.65 | 4.50 | 4.65 | 13.80 | 9,935.17 | |
| Deferred Pymts in Lieu of Tax | 1562-0000-00 | | | | | | | | | | | | | | | | | | | | | | |
| Deferred PILS Contra Account | 1563-0000-00 | | | | | | | | | | | | | | | | | | | | | | |
| PILS & Tax Variance - Lost ON SBD | 1592-0000-04 | 35,000.00 | | | | | 35,000.00 | | | | | 35,000.00 | | | | | 35,000.00 | | | | | 35,000.00 | |
| Carrying Charges - PILS & Tax Variance - Lost ON SBD | 1592-0000-05 | 571.60 | 32.70 | 29.53 | 32.70 | 94.93 | 666.53 | 31.64 | 32.70 | 31.64 | 95.98 | 762.51 | 32.70 | 32.70 | 31.64 | 97.04 | 859.55 | 44.59 | 43.15 | 44.59 | 132.33 | 991.88 | |
| | | 35,571.60 | 32.70 | 29.53 | 32.70 | 94.93 | 35,666.53 | 31.64 | 32.70 | 31.64 | 95.98 | 35,762.51 | 32.70 | 32.70 | 31.64 | 97.04 | 35,859.55 | 44.59 | 43.15 | 44.59 | 132.33 | 35,991.88 | |
| LRAM - Residential | 1568-0000-01 | 43,581.00 | -32,755.85 | | | -32,755.85 | 10,825.15 | | | | | 10,825.15 | | | | | 10,825.15 | | | 44,268.67 | 44,268.67 | 55,093.82 | |
| LRAM - GS<50 | 1568-0000-02 | 31,269.00 | 97,268.58 | | | 97,268.58 | 128,537.58 | | | | | 128,537.58 | | | | | 128,537.58 | | | 40,056.40 | 40,056.40 | 168,593.98 | |
| LRAM - GS>50 | 1568-0000-03 | 15,016.00 | -69,924.66 | | | -69,924.66 | -54,908.66 | | | | | -54,908.66 | | | | | -54,908.66 | | | -11,072.95 | -11,072.95 | -65,981.61 | |
| LRAM - Streetlights | 1568-0000-04 | 12,359.00 | -23,771.43 | | | -23,771.43 | -11,412.43 | | | | | -11,412.43 | | | | | -11,412.43 | | | -3,018.60 | -3,018.60 | -14,431.03 | |
| LRAM - USL | 1568-0000-06 | | -162.53 | | | -162.53 | -162.53 | | | | | -162.53 | | | | | -162.53 | | | -56.21 | -56.21 | -218.74 | |
| | | 102,225.00 | -29,345.89 | | | -29,345.89 | 72,879.11 | | | | | 72,879.11 | | | | | 72,879.11 | | | 70,177.31 | 70,177.31 | 143,056.42 | |
| LRAM - Carrying Charges | 1568-0000-05 | 1,314.63 | 738.83 | 61.50 | 68.09 | 868.42 | 2,183.05 | 65.89 | 68.09 | 65.89 | 199.87 | 2,382.92 | 68.09 | 68.09 | 65.89 | 202.07 | 2,584.99 | 92.85 | 89.85 | 92.85 | 275.55 | 2,860.54 | |
| | | 103,539.63 | -28,607.06 | 61.50 | 68.09 | -28,477.47 | 75,062.16 | 65.89 | 68.09 | 65.89 | 199.87 | 75,262.03 | 68.09 | 68.09 | 65.89 | 202.07 | 75,464.10 | 92.85 | 89.85 | 70,270.16 | 70,452.86 | 145,916.96 | |
| ***DISPOSITIONS:*** | | | | | | | | | | | | | | | | | | | | | | | |
| Disposition of Acct Balances Approved in 2013 | 1595-2013-00 | 44,601.91 | | | | | 44,601.91 | | | | | 44,601.91 | | | | | 44,601.91 | | | | | 44,601.91 | |
| Disposition of GA Acct Balances Approved in 2013 | 1595-2013-03 | 559,826.34 | | | | | 559,826.34 | | | | | 559,826.34 | | | | | 559,826.34 | | | | | 559,826.34 | |
| Disposition of GA Acct Balances Approved in 2013 | 1595-2013-04 | -496,981.46 | | | | | -496,981.46 | | | | | -496,981.46 | | | | | -496,981.46 | | | | | -496,981.46 | |
| | | 107,446.79 | | | | | 107,446.79 | | | | | 107,446.79 | | | | | 107,446.79 | | | | | 107,446.79 | |
| Carrying Charges for Dispositions Approved in 2013 | 1595-2013-01 | -7,628.29 | 100.38 | 90.67 | 100.38 | 291.43 | -7,336.86 | 97.14 | 100.38 | 97.14 | 294.66 | -7,042.20 | 100.38 | 100.38 | 97.14 | 297.90 | -6,744.30 | 136.88 | 132.47 | 136.88 | 406.23 | -6,338.07 | |
| | | 99,818.50 | 100.38 | 90.67 | 100.38 | 291.43 | 100,109.93 | 97.14 | 100.38 | 97.14 | 294.66 | 100,404.59 | 100.38 | 100.38 | 97.14 | 297.90 | 100,702.49 | 136.88 | 132.47 | 136.88 | 406.23 | 101,108.72 | |
| Disposition of Acct Balances 2015 | 1595-2015-00 | 48,493.95 | | | | | 48,493.95 | | | | | 48,493.95 | | | | | 48,493.95 | | | | | 48,493.95 | |
| Disposition of GA Acct Balances 2015 | 1595-2015-03 | 94,223.44 | | | | | 94,223.44 | | | | | 94,223.44 | | | | | 94,223.44 | | | | | 94,223.44 | |
| | | 142,717.39 | | | | | 142,717.39 | | | | | 142,717.39 | | | | | 142,717.39 | | | | | 142,717.39 | |
| Carrying Charges for Disposition Acct Bal 2015 | 1595-2015-01 | 19,049.26 | 133.33 | 120.43 | 133.33 | 387.09 | 19,436.35 | 129.03 | 133.33 | 129.03 | 391.39 | 19,827.74 | 133.33 | 133.33 | 129.03 | 395.69 | 20,223.43 | 181.82 | 175.95 | 181.82 | 539.59 | 20,763.02 | |
| | | 161,766.65 | 133.33 | 120.43 | 133.33 | 387.09 | 162,153.74 | 129.03 | 133.33 | 129.03 | 391.39 | 162,545.13 | 133.33 | 133.33 | 129.03 | 395.69 | 162,940.82 | 181.82 | 175.95 | 181.82 | 539.59 | 163,480.41 | |
| Disposition of Acct Balances Approved in 2010 | 1595-2010-00 | 48,738.96 | | | | | 48,738.96 | | | | | 48,738.96 | | | | | 48,738.96 | | | | | 48,738.96 | |
| Carrying Charges for Dispositions Approved in 2010 | 1595-2010-01 | 1,738.09 | 45.53 | 41.13 | 45.53 | 132.19 | 1,870.28 | 44.07 | 45.53 | 44.07 | 133.67 | 2,003.95 | 45.53 | 45.53 | 44.07 | 135.13 | 2,139.08 | 62.09 | 60.09 | 62.09 | 184.27 | 2,323.35 | |

12,696.86

ce had to be shown in PP&E for IFRS purposes.
a difference between the regulatory books and IFRS f/s.

1,906.61

**COLLUS PowerStream Corp**
**OEB QUARTERLY DEFERRAL ACCOUNT REPORTING**
**For the Twelve Months Ending Sunday, December 31, 2017**

| | | Opening | January | February | March | Quarter 1 | Balance | April | May | June | Quarter 2 | Balance | July | August | September | Quarter 3 | Balance | October | November | December | Quarter 4 | Balance | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 50,477.05 | 45.53 | 41.13 | 45.53 | 132.19 | 50,609.24 | 44.07 | 45.53 | 44.07 | 133.67 | 50,742.91 | 45.53 | 45.53 | 44.07 | 135.13 | 50,878.04 | 62.09 | 60.09 | 62.09 | 184.27 | 51,062.31 | |
| Disposition of Acct Balances Approved in 2012 | 1595-2012-00 | -103,647.69 | | | | | -103,647.69 | | | | | -103,647.69 | | | | | -103,647.69 | | | | | -103,647.69 | |
| Disposition of PILS Acct Balances Approved in 2012 | 1595-2012-02 | 16.85 | | | | | 16.85 | | | | | 16.85 | | | | | 16.85 | | | | | 16.85 | |
| Disposition of GA Acct Balances Approved in 2012 | 1595-2012-03 | 110,000.63 | | | | | 110,000.63 | | | | | 110,000.63 | | | | | 110,000.63 | | | | | 110,000.63 | |
| | | 6,369.79 | | | | | 6,369.79 | | | | | 6,369.79 | | | | | 6,369.79 | | | | | 6,369.79 | |
| Carrying Charges for Dispositions Approved in 2012 | 1595-2012-01 | -18,445.27 | 5.95 | 5.38 | 5.95 | 17.28 | -18,427.99 | 5.76 | 5.95 | 5.76 | 17.47 | -18,410.52 | 5.95 | 5.95 | 5.76 | 17.66 | -18,392.86 | 8.11 | 7.85 | 8.11 | 24.07 | -18,368.79 | |
| | | -12,075.48 | 5.95 | 5.38 | 5.95 | 17.28 | -12,058.20 | 5.76 | 5.95 | 5.76 | 17.47 | -12,040.73 | 5.95 | 5.95 | 5.76 | 17.66 | -12,023.07 | 8.11 | 7.85 | 8.11 | 24.07 | -11,999.00 | Regulatory |
| **TOTAL DISPOSITIONS** | | 299,986.72 | 285.19 | 257.61 | 285.19 | 827.99 | 300,814.71 | 276.00 | 285.19 | 276.00 | 837.19 | 301,651.90 | 285.19 | 285.19 | 276.00 | 846.38 | 302,498.28 | 388.90 | 376.36 | 388.90 | 1,154.16 | 303,652.44 | |
| **Total Deferral Accounts** | | 1,303,665.32 | -27,009.29 | -3,490.40 | -6,240.40 | -36,740.09 | 1,266,925.23 | 2,418.60 | 9,384.60 | 8,269.60 | 20,072.80 | 1,286,998.03 | 4,575.29 | 56,467.12 | -4,520.58 | 56,521.83 | 1,343,519.86 | 5,645.87 | -2,959.83 | 69,729.47 | 72,415.51 | 1,415,935.37 | |
| **Total Carrying Charges on Deferral Accounts** | | 30,603.51 | 1,755.84 | 988.43 | 1,094.60 | 3,838.87 | 34,442.38 | 1,059.56 | 1,104.17 | 1,081.95 | 3,245.68 | 37,688.06 | 1,131.98 | 1,141.29 | 1,160.65 | 3,433.92 | 41,121.98 | 1,638.20 | 1,598.26 | 1,653.80 | 4,890.26 | 46,012.24 | |
| **TOTAL** | | 1,334,268.83 | -25,253.45 | -2,501.97 | -5,145.80 | -32,901.22 | 1,301,367.61 | 3,478.16 | 10,488.77 | 9,351.55 | 23,318.48 | 1,324,686.09 | 5,707.27 | 57,608.41 | -3,359.93 | 59,955.75 | 1,384,641.84 | 7,284.07 | -1,361.57 | 71,383.27 | 77,305.77 | 1,461,947.61 | |
| | | | | | | | | | | | | | | | | | | | | | | -93,610.70 | MIST Meter |
| | | | | | | | | | | | | | | | | | | | | | | 1,368,336.91 | |

deferral credit balance

rs (see note above)

**COLLUS PowerStream Corp**
**OEB QUARTERLY VARIANCE ACCOUNT REPORTING**
**For the Twelve Months Ending December 31, 2017**

| | | Opening | January | February | March | Quarter 1 | Balance | April | May | June | Quarter 2 | Balance | July | August | September | Quarter 3 | Balance | October | November | December | Quarter 4 | Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RETAIL SETTLEMENT VARIANCE ACCOUNTS** | | | | | | | | | | | | | | | | | | | | | | |
| LV Variance Account | 1550-0000-00 | $1,160,201.07 | $46,773.34 | $45,848.61 | $41,185.89 | $133,807.84 | $1,294,008.91 | $36,881.96 | $42,500.20 | $50,825.35 | $130,207.51 | $1,424,216.42 | $43,666.12 | $41,917.42 | $51,271.14 | $136,854.68 | $1,561,071.10 | $34,309.05 | $47,623.95 | $44,865.13 | $126,798.13 | $1,687,869.23 |
| LV VA - Carrrying Charges | 1550-0000-01 | 14,948.70 | 1,083.91 | 1,018.49 | 1,170.45 | 3,272.85 | 18,221.55 | 1,169.93 | 1,243.38 | 1,241.70 | 3,655.01 | 21,876.56 | 1,330.57 | 1,371.36 | 1,365.02 | 4,066.95 | 25,943.51 | 1,988.76 | 1,966.91 | 2,093.14 | 6,048.81 | 31,992.32 |
| | | *1,175,149.77* | *47,857.25* | *46,867.10* | *42,356.34* | *137,080.69* | *1,312,230.46* | *38,051.89* | *43,743.58* | *52,067.05* | *133,862.52* | *1,446,092.98* | *44,996.69* | *43,288.78* | *52,636.16* | *140,921.63* | *1,587,014.61* | *36,297.81* | *49,590.86* | *46,958.27* | *132,846.94* | *1,719,861.55* |
| RSVA - WMS | 1580-0000-01 | -1,455,958.51 | 35,409.64 | -21,600.68 | -66,047.53 | -52,238.57 | -1,508,197.08 | -12,959.77 | -161,769.52 | 32,800.19 | -141,929.10 | -1,650,126.18 | -35,142.82 | 40,994.33 | 2,118.20 | 7,969.71 | -1,642,156.47 | -1,304.90 | -152,807.72 | 29,442.40 | -124,670.22 | -1,766,826.69 |
| RSVA - WMS - Carrying Charge | 1580-0000-02 | -24,657.43 | -1,360.22 | -1,198.71 | -1,347.32 | -3,906.25 | -28,563.68 | -1,363.58 | -1,421.14 | -1,521.55 | -4,306.27 | -32,869.95 | -1,541.62 | -1,574.46 | -1,486.60 | -4,602.68 | -37,472.63 | -2,092.06 | -2,026.19 | -2,288.40 | -6,406.65 | -43,879.28 |
| | | -1,480,615.94 | 34,049.42 | -22,799.39 | -67,394.85 | -56,144.82 | -1,536,760.76 | -14,323.35 | -163,190.66 | 31,278.64 | -146,235.37 | -1,682,996.13 | -36,684.44 | 39,419.87 | 631.60 | 3,367.03 | -1,679,629.10 | -3,396.96 | -154,833.91 | 27,154.00 | -131,076.87 | -1,810,705.97 |
| RSVA - WMS CBDR Class B | 1580-0000-04 | 67,204.11 | -1,749.24 | -670.73 | -2,199.34 | -4,619.31 | 62,584.80 | 1,271.54 | -162.69 | 741.13 | 1,849.98 | 64,434.78 | 523.30 | 240.51 | 2,775.92 | 3,539.73 | 67,974.51 | 824.22 | 330.27 | -3,970.43 | -2,815.94 | 65,158.57 |
| RSVA - WMS CBDR Class B - Carrying Charge | 1580-0000-06 | 1,001.88 | 62.79 | 55.23 | 60.52 | 178.54 | 1,180.42 | 56.58 | 59.66 | 57.59 | 173.83 | 1,354.25 | 60.20 | 60.69 | 58.95 | 179.84 | 1,534.09 | 86.60 | 84.82 | 88.07 | 259.49 | 1,793.58 |
| | | 68,205.99 | -1,686.45 | -615.50 | -2,138.82 | -4,440.77 | 63,765.22 | 1,328.12 | -103.03 | 798.72 | 2,023.81 | 65,789.03 | 583.50 | 301.20 | 2,834.87 | 3,719.57 | 69,508.60 | 910.82 | 415.09 | -3,882.36 | -2,556.45 | 66,952.15 |
| RSVA - WMS CBDR Class A | 1580-0000-03 | 0.00 | -0.59 | -0.64 | 0.59 | -0.64 | -0.64 | -0.74 | -1.15 | 1.38 | -0.51 | -1.15 | 14.77 | 14.64 | -13.41 | 16.00 | 14.85 | -2.51 | 4.16 | -16.50 | -14.85 | 0.00 |
| RSVA - WMS CBDR Class A - Carrying Charge | 1580-0000-05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | | 0.00 | -0.59 | -0.64 | 0.59 | -0.64 | -0.64 | -0.74 | -1.15 | 1.38 | -0.51 | -1.15 | 14.77 | 14.64 | -13.41 | 16.00 | 14.85 | -2.51 | 4.16 | -16.50 | -14.85 | 0.00 |
| RSVA - Total WMS | | -1,388,754.40 | 33,659.81 | -22,272.05 | -68,246.28 | -56,858.52 | -1,445,612.92 | -11,688.97 | -161,933.36 | 33,542.70 | -140,079.63 | -1,585,692.55 | -34,604.75 | 41,249.48 | 4,880.71 | 11,525.44 | -1,574,167.11 | -483.19 | -152,473.29 | 25,455.47 | -127,501.01 | -1,701,668.12 |
| RSVA - Total WMSCarrying Charges | | -23,655.55 | -1,297.43 | -1,143.48 | -1,286.80 | -3,727.71 | -27,383.26 | -1,307.00 | -1,361.48 | -1,463.96 | -4,132.44 | -31,515.70 | -1,481.42 | -1,513.77 | -1,427.65 | -4,422.84 | -35,938.54 | -2,005.46 | -1,941.37 | -2,200.33 | -6,147.16 | -42,085.70 |
| | | *-1,412,409.95* | *32,362.38* | *-23,415.53* | *-69,533.08* | *-60,586.23* | *-1,472,996.18* | *-12,995.97* | *-163,294.84* | *32,078.74* | *-144,212.07* | *-1,617,208.25* | *-36,086.17* | *39,735.71* | *3,453.06* | *7,102.60* | *-1,610,105.65* | *-2,488.65* | *-154,414.66* | *23,255.14* | *-133,648.17* | *-1,743,753.82* |
| RSVA - NW | 1584-0000-01 | 64,934.21 | -4,005.40 | -2,390.87 | -29,375.36 | -35,771.63 | 29,162.58 | -13,548.40 | 10,338.25 | 30,951.25 | 27,741.10 | 56,903.68 | 5,342.72 | -656.22 | 26,946.28 | 31,632.78 | 88,536.46 | -18,011.36 | 20,353.59 | -21,864.49 | -19,522.26 | 69,014.20 |
| RSVA - NW - Carrying Charge | 1584-0000-02 | -1,228.50 | 60.66 | 51.41 | 54.69 | 166.76 | -1,061.74 | 26.37 | 14.59 | 23.46 | 64.42 | -997.32 | 53.16 | 58.15 | 55.68 | 166.99 | -830.33 | 112.79 | 86.95 | 115.78 | 315.52 | -514.81 |
| | | *63,705.71* | *-3,944.74* | *-2,339.46* | *-29,320.67* | *-35,604.87* | *28,100.84* | *-13,522.03* | *10,352.84* | *30,974.71* | *27,805.52* | *55,906.36* | *5,395.88* | *-598.07* | *27,001.96* | *31,799.77* | *87,706.13* | *-17,898.57* | *20,440.54* | *-21,748.71* | *-19,206.74* | *68,499.39* |
| RSVA - CN | 1586-0000-01 | 159,277.71 | -107.37 | 689.06 | -11,981.53 | -11,399.84 | 147,877.87 | -5,989.41 | 7,113.15 | 13,738.53 | 14,862.27 | 162,740.14 | 975.65 | -1,947.58 | 14,448.28 | 13,476.35 | 176,216.49 | -10,936.70 | 10,775.29 | -13,370.56 | -13,531.97 | 162,684.52 |
| RSVA - CN - Carrying Charge | 1586-0000-02 | 985.84 | 148.80 | 134.31 | 149.35 | 432.46 | 1,418.30 | 133.70 | 132.56 | 134.71 | 400.97 | 1,819.27 | 152.04 | 152.95 | 146.26 | 451.25 | 2,270.52 | 224.49 | 203.77 | 224.29 | 652.55 | 2,923.07 |
| | | *160,263.55* | *41.43* | *823.37* | *-11,832.18* | *-10,967.38* | *149,296.17* | *-5,855.71* | *7,245.71* | *13,873.24* | *15,263.24* | *164,559.41* | *1,127.69* | *-1,794.63* | *14,594.54* | *13,927.60* | *178,487.01* | *-10,712.21* | *10,979.06* | *-13,146.27* | *-12,879.42* | *165,607.59* |
| RSVA - Power | 1588-0000-01 | 1,003,647.92 | -88,239.51 | 57,908.72 | -51,068.87 | -81,399.66 | 922,248.26 | -419,459.96 | -66,762.20 | 522,258.69 | 36,036.53 | 958,284.79 | -251,504.47 | -22,397.59 | 47,087.45 | -226,814.61 | 731,470.18 | 570,656.26 | 275,681.80 | -1,049,722.79 | -203,384.73 | 528,085.45 |
| RSVA - Power - Carrying Charge | 1588-0000-02 | -71,826.28 | 937.65 | 772.45 | 909.32 | 2,619.42 | -69,206.86 | 833.81 | 469.73 | 394.22 | 1,697.76 | -67,509.10 | 895.27 | 660.31 | 618.76 | 2,174.34 | -65,334.76 | 931.87 | 1,605.36 | 2,010.08 | 4,547.31 | -60,787.45 |
| | | *931,821.64* | *-87,301.86* | *58,681.17* | *-50,159.55* | *-78,780.24* | *853,041.40* | *-418,626.15* | *-66,292.47* | *522,652.91* | *37,734.29* | *890,775.69* | *-250,609.20* | *-21,737.28* | *47,706.21* | *-224,640.27* | *666,135.42* | *571,588.13* | *277,287.16* | *-1,047,712.71* | *-198,837.42* | *467,298.00* |
| RSVA - Power - Global Adjmt | 1588-0000-03 | 375,566.66 | -146,020.64 | 497,067.33 | -656,726.41 | -305,679.72 | 69,886.94 | 443,506.24 | 709,944.36 | 19,116.51 | 1,172,567.11 | 1,242,454.05 | -548,950.08 | 297,518.57 | -209,408.57 | -460,840.08 | 781,613.97 | -91,378.23 | 150,442.79 | 110,498.45 | 169,563.01 | 951,176.98 |
| RSVA - Power - GA - Carrying Charges | 1588-0000-04 | 64,416.47 | 350.87 | 193.70 | 678.84 | 1,223.41 | 65,639.88 | 63.19 | 479.64 | 1,106.03 | 1,648.86 | 67,288.74 | 1,160.76 | 647.90 | 895.99 | 2,704.65 | 69,993.39 | 995.75 | 850.98 | 1,071.00 | 2,917.73 | 72,911.12 |
| | | *439,983.13* | *-145,669.77* | *497,261.03* | *-656,047.57* | *-304,456.31* | *135,526.82* | *443,569.43* | *710,424.00* | *20,222.54* | *1,174,215.97* | *1,309,742.79* | *-547,789.32* | *298,166.47* | *-208,512.58* | *-458,135.43* | *851,607.36* | *-90,382.48* | *151,293.77* | *111,569.45* | *172,480.74* | *1,024,088.10* |
| Smart Metering Entity Charge Variance Account | 1551-0000-00 | -17,523.52 | -211.36 | 524.76 | -609.66 | -296.26 | -17,819.78 | -334.65 | -768.42 | -254.69 | -1,357.76 | -19,177.54 | -848.50 | -836.34 | -220.00 | -1,904.84 | -21,082.38 | -974.44 | -496.30 | -1,432.43 | -2,903.17 | -23,985.55 |
| Smart Metering Entity Chrg - Carrying Charges | 1551-0000-01 | -298.79 | -16.37 | -14.97 | -16.08 | -47.42 | -346.21 | -16.11 | -16.96 | -17.11 | -50.18 | -396.39 | -17.92 | -18.71 | -18.86 | -55.49 | -451.88 | -26.86 | -27.19 | -28.73 | -82.78 | -534.66 |
| | | *-17,822.31* | *-227.73* | *509.79* | *-625.74* | *-343.68* | *-18,165.99* | *-350.76* | *-785.38* | *-271.80* | *-1,407.94* | *-19,573.93* | *-866.42* | *-855.05* | *-238.86* | *-1,960.33* | *-21,534.26* | *-1,001.30* | *-523.49* | *-1,461.16* | *-2,985.95* | *-24,520.21* |
| **TOTAL** | | **1,340,691.54** | **-156,883.04** | **578,387.47** | **-775,162.45** | **-353,658.02** | **987,033.52** | **30,270.70** | **541,393.44** | **671,597.39** | **1,243,261.53** | **2,230,295.05** | **-783,830.85** | **356,205.93** | **-63,359.51** | **-490,984.43** | **1,739,310.62** | **485,402.73** | **354,653.24** | **-902,285.99** | **-62,230.02** | **1,677,080.60** |
| **RSVA** | | **1,357,349.65** | **-158,151.13** | **577,375.56** | **-776,822.22** | **-357,597.79** | **999,751.86** | **29,366.81** | **540,431.98** | **670,178.34** | **1,239,977.13** | **2,239,728.99** | **-785,923.31** | **354,847.74** | **-64,994.71** | **-496,070.28** | **1,743,658.71** | **483,181.39** | **351,907.83** | **-905,571.22** | **-70,482.00** | **1,673,176.71** |
| **CARRYING CHARGES** | | **-16,658.11** | **1,268.09** | **1,011.91** | **1,659.77** | **3,939.77** | **-12,718.34** | **903.89** | **961.46** | **1,419.05** | **3,284.40** | **-9,433.94** | **2,092.46** | **1,358.19** | **1,635.20** | **5,085.85** | **-4,348.09** | **2,221.34** | **2,745.41** | **3,285.23** | **8,251.98** | **3,903.89** |
| **TOTAL** | | **1,340,691.54** | **-156,883.04** | **578,387.47** | **-775,162.45** | **-353,658.02** | **987,033.52** | **30,270.70** | **541,393.44** | **671,597.39** | **1,243,261.53** | **2,230,295.05** | **-783,830.85** | **356,205.93** | **-63,359.51** | **-490,984.43** | **1,739,310.62** | **485,402.73** | **354,653.24** | **-902,285.99** | **-62,230.02** | **1,677,080.60** |

**COLLUS POWER CORP.**
**REGULATORY LIABILITY**
**31-Dec-17**

| | REF | 2017 |
|---|---|---|
| Deferral Accounts | See detailed excel sch | $1,461,947.61 |
| Less: Meter Capital in PPE for IFRS purposes | | -$93,610.70 |
| RSVA | See detailed excel sch | $1,677,080.60 |
| | | $3,045,417.51 |

**MATCH TO FINANCIAL STATEMENTS**

| | |
|---|---|
| Note - Reg Debits | $ 3,008,511.00 |
| Note - Reg Credits | $ (11,999.00) |
| | $ 2,996,512.00 |
| Note - Deferred Chrgs | $ 48,905.00 |
| | $ 3,045,417.00 |

## 11. Regulatory Deferral Accounts

All amounts deferred as regulatory deferral account debit balances are subject t the OEB. As such, amounts subject to deferral could be altered by the regulator recovery periods are those expected and the actual recovery or settlement period based on OEB approval. Where no recovery period is noted, the deferral an applied for disposition at the time of the next Cost of Service Application to tl recovery period will be determined by the OEB at that time.

Due to previous, existing or expected future regulatory articles or decisions, th has the following amounts expected to be recovered from customers (returned to future periods and as such regulatory deferral account balances are comprised o

| | 2016 | Disposition May 2017 | Balances Arising in the Period | Recover |
|---|---|---|---|---|
| **Regulatory deferral debits:** | (Note 12) | | | |
| Stranded assets | $ 527,592 | $ - | $ 6,154 | $ |
| OEB Cost assessment variance | 27,817 | - | 39,321 | |
| Energy East consultation costs | 2,315 | - | 27 | |
| IFRS transition costs | 201,286 | - | 2,272 | |
| Late payment penalty settlement | (2,217) | - | - | |
| Green Energy Renewable Connection | 8,711 | - | 3,985 | |
| Stranded meters | 9,891 | - | 44 | |
| Smart Grid | 4,711 | - | 54 | |
| MIST Meters | - | - | 1,907 | |
| PILs tax variance - Ontario SBD | 35,572 | - | 420 | |
| LRAMVA | 103,540 | - | 42,377 | |
| RARA approved May 1, 2013, 2 yr | 99,818 | - | 1,290 | |
| RARA approved May 1, 2015, 1 yr | 161,767 | - | 1,714 | |
| RARA approved May 1, 2010, 4 yr | 50,477 | - | 585 | |
| Retail settlement variances | 1,340,692 | - | 336,389 | |
| | 2,571,972 | - | 436,539 | |
| Miscellaneous deferred debits | 115,064 | - | (66,159) | |
| | $ 2,687,036 | $ - | $ 370,380 | $ |
| **Regulatory deferral credits:** | | | | |
| RARA approved May 1, 2012, 2 yr | 12,075 | - | (76) | |
| | $ 12,075 | $ - | $ (76) | $ |
| **Net regulatory asset** | $ 2,674,961 | $ - | $ 370,456 | $ |

# Corp.
**d in CDN$)**
**' 31, 2017**

o approval by
s. Remaining
ls could differ
nount will be
he OEB. The

ie corporation
customers) in
f:

| ry | 2017 |
|---|---|
| - | $ 533,746 |
| - | 67,138 |
| - | 2,342 |
| - | 203,558 |
| - | (2,217) |
| - | 12,696 |
| - | 9,935 |
| - | 4,765 |
| - | 1,907 |
| - | 35,992 |
| - | 145,917 |
| - | 101,108 |
| - | 163,481 |
| - | 51,062 |
| - | 1,677,081 |
| - | 3,008,511 |
| - | 48,905 |
| - | $3,057,416 |
| - | 11,999 |
| - | $ 11,999 |
| - | $3,045,417 |

**APPENDIX B:**
**December 31, 2017 Audited Financial Statements of Collus PowerStream Corp.**

# Collus PowerStream Corp.

## Financial Statements

## For the year ended December 31, 2017
**(expressed in CDN$)**

# Collus PowerStream Corp.
## Financial Statements
### For the year ended December 31, 2017

Table of Contents

# COLLINS BARROW SGB LLP
## CHARTERED PROFESSIONAL ACCOUNTANTS

### INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Collus PowerStream Corp.:

**Report on the Financial Statements**

We have audited the accompanying financial statements of Collus PowerStream Corp., which comprise the balance sheet as at December 31, 2017 and the statements of comprehensive income, changes in equity and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

**Management's Responsibility for the Financial Statements**

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditor's Responsibility**

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the corporation's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the corporation's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the financial statements present fairly, in all material respects, the financial position of Collus PowerStream Corp. as at December 31, 2017 and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

*Collins Barrow SGB LLP*

Licensed Public Accountants
Collingwood, Ontario
March 23, 2018

# Collus PowerStream Corp.
## Balance Sheet
**(expressed in CDN$)**

| As at December 31 | | 2017 | 2016 |
|---|---|---|---|
| **Assets** | | | (Note 12) |
| **Current** | | | |
| Cash and bank | (Note 6) | **$ 2,255,077** | $ 940,680 |
| Accounts receivable | (Note 7) | **4,215,147** | 4,850,878 |
| Unbilled energy revenue | | **3,863,870** | 4,852,979 |
| Inventory | | **288,487** | 310,242 |
| Payments in lieu of taxes receivable | | **74,002** | 27,203 |
| Prepaid expenses | | **364,344** | 355,964 |
| | | **11,060,927** | 11,337,946 |
| Deferred taxes | (Note 8) | **442,488** | 560,930 |
| Property, plant and equipment | (Note 9) | **22,131,745** | 19,736,310 |
| Intangibles | (Note 10) | **910,164** | 936,002 |
| **Total Assets** | | **34,545,324** | 32,571,188 |
| Regulatory deferrals | (Note 11) | **3,057,416** | 2,687,036 |
| **Total Assets and Regulatory Deferrals** | | **$ 37,602,740** | $ 35,258,224 |
| **Liabilities and Shareholder's Equity** | | | |
| **Current** | | | |
| Accounts payable and accruals | (Note 13) | **$ 7,076,053** | $ 8,759,418 |
| Customer deposits and credits | (Note 14) | **634,824** | 599,416 |
| Current portion of long-term debt | (Note 16) | **573,858** | 503,495 |
| | | **8,284,735** | 9,862,329 |
| Long-term customer deposits | (Note 14) | **265,077** | 278,020 |
| Long-term debt | (Note 16) | **13,922,124** | 11,447,235 |
| Contributions in aid of construction | (Note 15) | **3,225,522** | 2,769,851 |
| Employee future benefits | (Note 17) | **844,331** | 838,844 |
| **Total Liabilities** | | **26,541,789** | 25,196,279 |
| **Shareholder's Equity** | | | |
| Share capital | (Note 18) | **5,101,340** | 5,101,340 |
| Miscellaneous paid in capital | (Note 19) | **2,966,014** | 2,966,014 |
| Retained earnings | | **3,109,274** | 2,110,192 |
| Accumulated other comprehensive deficit | | **(127,676)** | (127,676) |
| **Total Shareholder's Equity** | | **11,048,952** | 10,049,870 |
| **Total Liabilities and Shareholder's Equity** | | **37,590,741** | 35,246,149 |
| Regulatory deferrals | (Note 11) | **11,999** | 12,075 |
| **Total Liabilities, Equity and Regulatory Deferrals** | | **$ 37,602,740** | $ 35,258,224 |

On behalf of the Board:

Director Dan Horchik Director

# Collus PowerStream Corp.

## Statement of Comprehensive Income

**(expressed in CDN$)**

| For the year ended December 31 | | 2017 | 2016 |
|---|---|---|---|
| | | | (Note 12) |
| **Revenues** | | | |
| Sale of energy | | **$ 35,499,898** | $ 36,316,681 |
| Distribution revenue | | **6,811,090** | 6,741,148 |
| Other revenue | | **489,055** | 595,882 |
| | | **42,800,043** | 43,653,711 |
| **Cost of power purchased** | | **35,815,725** | 36,651,902 |
| | | **6,984,318** | 7,001,809 |
| **Expenses** | | | |
| Amortization | (Note 23) | **939,422** | 836,935 |
| Billing and collecting | (Note 30) | **1,204,657** | 1,054,295 |
| Operations and maintenance | (Note 30) | **2,189,894** | 2,482,131 |
| General and administrative | (Note 30) | **1,168,962** | 1,354,024 |
| Loss on disposal of property, plant and equipment | | **25,935** | 62,919 |
| Donations and Low-Income Energy Assistance Program | | **10,441** | 10,108 |
| | | **5,539,311** | 5,800,412 |
| **Income from operations** | | **1,445,007** | 1,201,397 |
| Finance income | (Note 25) | **40,051** | 32,790 |
| Finance cost | (Note 25) | **(599,757)** | (506,604) |
| **Income before income taxes and net regulatory movements** | | **885,301** | 727,583 |
| **Income taxes** (Note 8) | | | |
| Current | | **138,233** | 150,279 |
| Deferred | | **118,442** | 145,543 |
| | | **256,675** | 295,822 |
| **Income before net regulatory movements** | | **628,626** | 431,761 |
| Net movement on regulatory deferral accounts | (Note 11) | **370,456** | 380,988 |
| **Net income and regulatory movements** | | **999,082** | 812,749 |
| **Other comprehensive income: items that will not be reclassified to profit or loss, net of income tax** | | | |
| Remeasurement of defined benefit pension plan | | **-** | (93,928) |
| Deferred tax on re-measurements | | **-** | 24,891 |
| | | **-** | (69,037) |
| **Total income and other comprehensive income** | | **$ 999,082** | $ 743,712 |

# Collus PowerStream Corp.
## Statement of Changes in Equity
**(expressed in CDN$)**

## For the year ended December 31

(Note 12)

| | Share Capital | Miscellaneous Paid In Capital | Accumulated Other Comprehensive Deficit | Retained Earnings | Total |
|---|---|---|---|---|---|
| **Balance January 1, 2016** | **$ 5,101,340** | **$ 2,966,014** | **$ (58,639)** | **$ 1,420,441** | **$ 9,429,156** |
| Net income and regulatory movements | - | - | - | 812,749 | 812,749 |
| Other comprehensive income | - | - | (69,037) | - | (69,037) |
| Dividends | - | - | - | (122,998) | (122,998) |
| **Balance December 31, 2016** | **$ 5,101,340** | **$ 2,966,014** | **$ (127,676)** | **$ 2,110,192** | **$ 10,049,870** |
| Net income and regulatory movements | - | - | - | 999,082 | 999,082 |
| **Balance December 31, 2017** | **$ 5,101,340** | **$ 2,966,014** | **$ (127,676)** | **$ 3,109,274** | **$ 11,048,952** |

# Collus PowerStream Corp.
## Statement of Cash Flows
**(expressed in CDN$)**

| For the year ended December 31 | | 2017 | 2016 |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Total income and other comprehensive income | | **$ 999,082** | $ 743,712 |
| Adjustments for items not affecting cash: | | | |
| Amortization | (Note 23) | **939,422** | 836,935 |
| Vehicle amortization, allocated to other accts | (Note 23) | **227,795** | 224,957 |
| Loss on disposal of property, plant and equipment | | **25,935** | 62,919 |
| Gain on disposal of property, plant and equipment | | **(10,000)** | (23,506) |
| Contributions in aid of construction | (Note 15) | **(72,285)** | (45,635) |
| Income taxes | | **256,675** | 270,931 |
| Finance income | (Note 25) | **(40,051)** | (32,790) |
| Finance expense | (Note 25) | **599,757** | 506,604 |
| | | **2,926,330** | 2,544,127 |
| Changes in non-cash working capital: | | | |
| Accounts receivable | | **635,731** | (761,995) |
| Unbilled energy revenue | | **989,109** | (620,665) |
| Inventory | | **21,755** | (24,367) |
| Prepaid expenses | | **(8,380)** | 110,129 |
| Accounts payable and accruals | | **(1,681,094)** | 1,538,894 |
| Customer deposits and credit balances | | **35,408** | (234,892) |
| Employee future benefits | | **(26,273)** | 439,097 |
| Payments in lieu of corporate taxes paid | | **(185,032)** | (183,057) |
| | | **2,707,554** | 2,807,271 |
| **Cash flows from investing activities** | | | |
| Purchase of property, plant and equipment | (Note 9) | **(3,548,749)** | (3,696,344) |
| Proceeds of contributions in aid of construction | (Note 15) | **527,957** | 1,739,589 |
| Purchase of computer software | (Note 10) | **(13,999)** | (69,340) |
| Proceeds on disposal of property, plant and equipment | | **10,000** | 130,393 |
| Proceeds from disposal of investment | | **-** | 100 |
| Capital contributions in aid of construction paid | (Note 10) | **-** | (553,415) |
| Net decrease in regulatory accounts | | **(370,456)** | (1,282,593) |
| Interest received | | **40,051** | 32,790 |
| | | **(3,355,196)** | (3,698,820) |
| **Cash flows from financing activities** | | | |
| Decrease in long-term customer deposits | | **(12,943)** | (3,435) |
| Proceeds of long-term debt | | **3,100,000** | - |
| Repayments of long-term debt | | **(554,749)** | (491,505) |
| Interest paid | | **(570,269)** | (492,833) |
| Dividends paid | (Note 20) | **-** | (122,998) |
| | | **1,962,039** | (1,110,771) |
| **Increase (decrease) in cash during the year** | | **1,314,397** | (2,002,320) |
| **Cash and bank**, beginning of year | | **940,680** | 2,943,000 |
| **Cash and bank**, end of year | | **$ 2,255,077** | $ 940,680 |

## 1. Corporate Information

Collus PowerStream Corp. (the "corporation") (formerly known as Collus Power Corp.) was incorporated on April 13, 2000, under the Business Corporations Act (Ontario), and is wholly owned by its parent holding company Collingwood PowerStream Utility Services Corp. The holding company is owned 50% by the Town of Collingwood and 50% by Alectra Utilities Corporation (formerly known as PowerStream Inc.). The address of the corporation's office and principal place of business is 43 Stewart Road, Collingwood, Ontario, Canada.

The principal activity of the corporation is to distribute electricity to approximately 17,000 customers in the service area of Collingwood, Thornbury, Stayner, and Creemore in the Province of Ontario, under licences issued by the Ontario Energy Board ("OEB"). The corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval.

As a condition of its distribution licence, the corporation is required to meet specified Conservation and Demand Management ("CDM") targets for reductions in electricity consumption and peak electricity demand. As part of this initiative, the corporation is delivering Ontario Power Authority ("OPA") funded programs in order to meet its target.

Under the Green Energy and Green Economy Act, 2009, the corporation has new opportunities and responsibilities for enabling renewable generation.

## 2. Basis of Preparation

(a) Statement of compliance

The financial statements of the corporation 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.

The financial statements were authorized for issue by the Board of Directors on March 23, 2018.

(b) Basis of measurement

The financial statements have been prepared on a historical cost basis.

(c) Presentation currency

The financial statements are presented in Canadian dollars (CDN$), which is also the corporation's functional currency, and all values are rounded to the nearest dollar, unless otherwise indicated.

(d) Use of estimates and judgments

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It also requires management to exercise judgment in applying the corporation's accounting policies. The areas involving a higher degree of judgment, complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

## 2. Basis of Preparation Continued

(e) Explanation of activities subject to rate regulation

The corporation, as an electricity distributor, is both licensed and regulated by the Ontario Energy Board "OEB" which has a legislative mandate to oversee various aspects of the electricity industry. The OEB exercises statutory authority through setting or approving all rates charged by the corporation and establishing standards of service for the corporation's customers.

The OEB has broad powers relating to licensing, standards of conduct and service and the regulation of rates charged by the corporation and other electricity distributors in Ontario. The Ontario government enacted the Energy Competition Act, 1998, to introduce competition to the Ontario energy market. Rates are set by the OEB on an annual basis for May 1 to April 30.

Regulatory risk

Regulatory risk is the risk that the Province and its regulator, the OEB, 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.

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. The 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 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.

## 3. Significant Accounting Policies

The preparation and presentation of financial statements can be significantly affected by the accounting policies selected by the corporation. The financial statements reflect the following significant accounting policies, which are an integral part of understanding them.

(a) Regulatory Deferral Accounts

The corporation has adopted IFRS 14 Regulatory Deferral Accounts. In accordance with IFRS 14, the corporation has continued to apply the accounting policies it applied in accordance with 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.

**3. Significant Accounting Policies Continued**

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current period or in prior period(s), that 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), that 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 corporation 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 or expense in electricity distribution service charges.

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 deferral accounts. 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.

(b) Revenue

Revenue is recognized to the extent that it is probable that economic benefits will flow to the corporation and that the revenue can be reliably measured. Revenue is comprised of sales and distribution of energy, pole use rental, collection charges, and other miscellaneous revenues.

Sale and distribution of energy

The corporation is licensed by the OEB to distribute electricity. As a licensed distributor, the corporation 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 corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the corporation ultimately collects these amounts from customers. The corporation 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 the sale and distribution of electricity is recognized on an accrual basis, including unbilled revenues accrued in respect of electricity delivered but not yet billed. Sale and distribution of energy revenue is comprised of customer billings for distribution service charges. Customer billings for distribution service charges are recorded based on meter readings.

Other

Other revenues, which include revenues from pole use rental, collection charges and other miscellaneous revenues are recognized at the time services are provided. Where the corporation 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.

**3. Significant Accounting Policies Continued**

Contributions in aid of construction

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 will provide customers with ongoing access to the supply of electricity, these contributions are classified as contributions in aid of construction and are amortized as revenue on a straight-line basis over the useful life of the constructed or contributed asset. The amortization of contributed capital is included in Other revenue on the Statement of Comprehensive Income.

(c) Cash and Bank

Cash and bank includes cash on hand, deposits held on demand 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.

(d) Financial Assets

Financial assets - classified as loans and receivables

These include cash and bank, accounts receivable and unbilled energy revenue and are initially recognized at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest rate method less any impairment. The carrying amounts approximate fair value due to the short-term maturity of these instruments.

Collectability of accounts receivable is reviewed on an ongoing basis. 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 corporation 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.

Impairment of Financial assets

A financial asset not carried at fair value through income is assessed at each reporting date to determine whether there is objective evidence that it is impaired. A financial asset is impaired if objective evidence indicates that a loss event has occurred after the initial recognition of the asset, and that the loss event had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

**3. Significant Accounting Policies Continued**

(d) Financial Assets continued

The corporation considers evidence of impairment for receivables at both a specific asset and collective level. All individually significant receivables are assessed for specific impairment. All individually significant receivables found not to be specifically impaired are then collectively assessed for any impairment that has been incurred but not yet identified. Receivables that are not individually significant are collectively assessed for impairment by grouping together receivables with similar risk characteristics. In assessing collective impairment the corporation uses historical trends of the probability of default, timing of recoveries and the amount of loss incurred, adjusted for management's judgment as to whether current economic and credit conditions are such that the actual losses are likely to be greater or less than suggested by historical trends.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate. Losses are recognized in income and reflected in an allowance account against receivables. Interest on the impaired asset continues to be recognized through the unwinding of the discount. When a subsequent event causes the amount of impairment loss to decrease, the decrease in impairment loss is reversed through income.

(e) Financial Liabilities

Accounts payable and accruals, customer deposits and credits and long-term debt are classified as other financial liabilities and are initially measured at fair value. Subsequently, they are measured at amortized cost using the effective interest rate method less any impairment.

Customer Deposits

Customers may be required to post security to obtain electricity or other services, which are refundable. Where the security posted is in the form of cash and bank, these amounts are recorded in the accounts as deposits. Deposits to be refunded to customers within the next fiscal year are classified as a current liability. Interest rates paid on customer deposits are based on the Bank of Canada's prime business rate less 2%.

(f) Finance Income and Finance Costs

Finance income is comprised of interest income on funds invested such as cash and short-term investments. 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, impairment losses recognized on financial assets and net interest on employee future benefits.

(g) Inventory

Cost of inventory is comprised 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.

**Notes to Financial Statements (expressed in CDN$)**

## 3. Significant Accounting Policies Continued

(h) 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 corporation, including eligible borrowing costs.

Amortization of PP&E is recorded in the statement of comprehensive income on a straight-line basis over the estimated useful life of the related asset. Half of a year's amortization is taken for the first year, regardless of when the property was actually put into service during the year. The estimated useful lives, residual values and amortization 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 are as follows:

| | |
|---|---|
| Buildings | 50 years |
| Distribution stations | 20 - 45 years |
| Distribution lines | 40 - 60 years |
| Distribution transformers | 40 years |
| Distribution services | 40 years |
| Meters | 15 years |
| Vehicles | 5 - 8 years |
| Office equipment | 10 years |
| Tools and equipment | 10 years |
| Communication equipment | 10 years |
| System supervisory equipment | 15 years |

Work-in-Progress assets are not amortized until the project is complete and ready for use.

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 corporation's distribution system reliability. These are included in work-in-progress (Note 9) and not amortized.

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 recognized as contributions in aid of construction. The contribution represents the corporation's obligation to continue to provide customers access to the supply of electricity and is amortized to income over the economic useful life of the contributed asset ranging between 40 and 45 years.

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. When an item of property, plant and equipment with related contributions in aid of construction is disposed, the remaining contributions are recognized in full in the statement of comprehensive income.

**3. Significant Accounting Policies Continued**

(i) Borrowing Costs

The corporation 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 will be suspended during periods in which active development is interrupted. Capitalization should cease when substantially all of the activities necessary to prepare the asset for its intended use or sale are complete.

(j) Intangible Assets

Paid Capital Contributions include amounts paid by the corporation for capital expenditures under a Capital Cost Recovery Agreement. The contribution is measured at cost less accumulated amortization and accumulated impairment losses. They are not amortized until put into use.

Computer software that is acquired or developed by the corporation, 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.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Half of a year's amortization is taken for the first year in service. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date. The estimated useful lives for the current and comparative years are:

| | |
|---|---|
| Paid Capital Contributions | 40 years |
| Computer software | 5 years |

Goodwill represents the cost of acquired local distribution companies in Stayner, Creemore and Thornbury in excess of fair value of the net identifiable assets purchased. Goodwill is measured at cost and is not amortized.

(k) Impairment of Non-Financial Assets

At the end of each reporting period, the corporation 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 of disposal, 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 corporation has one cash-generating unit for which impairment testing is performed. An impairment loss is charged to the statement of comprehensive income, except to the extent it reverses gains previously recognized in other comprehensive income.

At the end of each reporting period or when an indicator for impairment exists, the corporation conducts an internal assessment of goodwill. An impairment loss in respect of goodwill is not reversed.

## 3. Significant Accounting Policies Continued

(l) Employee Future Benefits

Pension plan

The employees of the corporation participate in the Ontario Municipal Employees Retirement System ("OMERS"). The corporation also makes contributions to the OMERS plan on behalf of its employees. The plan has a defined benefit option at retirement available to 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. However, the plan is accounted for as a defined contribution plan as insufficient information is available to account for the plan as a defined benefit plan. The corporation is only one of a number of employers that participates in the plan and the financial information provided to the corporation on the basis of the contractual agreements is usually insufficient to measure the corporation's proportionate share in the plan assets and liabilities on defined benefit accounting requirements. The contribution payable in exchange for services rendered during a period is recognized as an expense during that period.

Post employment medical and life insurance plan

A defined benefit plan is a post-employment benefit plan other than a defined contribution plan. The corporation's net obligation on behalf of its retired employees unfunded 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 corporation, 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 corporation 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 the terms of the liabilities.

Remeasurements of the defined benefit obligation are recognized in other comprehensive income. The remeasurements include actuarial gains and losses.

Service costs are recognized in operating expenses and include current and past service costs as well as gains and losses on curtailments.

Net interest expense is recognized in finance costs 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.

**3. Significant Accounting Policies Continued**

(m) Employee Future Benefits Continued

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.

(n) Payments in Lieu of Taxes Payable

Tax status

The corporation is a Municipal Electricity Utility (“MEU”) for purposes of the payments in lieu of taxes (“PILs”) regime contained in the Electricity Act, 1998. As a MEU, the corporation is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the corporation is required to make, for each taxation year, PILs to 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

Provision in lieu of taxes ("PILs") is comprised of current and deferred tax. Current tax and deferred tax are recognized in net income except to the extent that it relates to items recognized directly in Other Comprehensive Income.

Current PILs are recognized on the taxable income or loss for the current year plus any adjustment in respect of previous years. Current PILs are determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date.

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).

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 corporation reassesses both recognized and unrecognized deferred tax assets. The corporation 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. Significant Accounting Policies Continued**

(o) Change in Accounting Policy

The amendments to IAS 7 "Statement of Cash Flows" were issued to improve information provided to users of financial statements about the entity's changes in liabilities arising from financing activities. These amendments were implemented with prospective application and had no impact on the corporation's financial statements. (Note 31)

(p) Future Changes in Accounting Policy and Disclosures

The corporation is evaluating the adoption of the following new and revised standards along with any subsequent amendments. Management anticipates that all of the relevant pronouncements will be adopted in the corporation's accounting policies for the first period beginning after the effective date of the pronouncement. Certain other new standards and interpretations have been issued but are not expected to have a material impact on the corporation's financial statements and therefore have not been described here.

*IFRS 9 Financial Instruments*

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 corporation 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 IFRS. The effective date for IFRS 15 is January 1, 2018. The corporation is in the process of evaluating the impact of the new standard.

*IFRS 16 Leases*

IFRS 16 is effective for periods beginning on or after January 1, 2019. The new requirements eliminate nearly all off balance sheet accounting for leases and redefine many commonly used financial ratios and performance metrics. This will increase comparability, but may also affect covenants, credit ratings, borrowing costs and stakeholder perceptions. IFRS 16 does not require a company to capitalize leases of low-value assets that, at the time of issuing IFRS 16 would have a capital value of $5,000 US or less. Management has yet to fully assess the impact of the Standard. However, management has identified that the corporation currently has the following two leases:

- Three separate photocopier leases for an aggregate annual lease cost of $8,616, with a term of 36 months, beginning February 1, 2017
- Building lease with the Town of Collingwood for $216,000 annually, currently on a month-to month basis with one year notice required

In order to determine the impact management is in the process of deciding which transitional provision to adopt, assessing current disclosures for leases as these are likely to form the basis of the amounts to be capitalized and become right-of-use assets, and assessing the additional disclosures that will be required.

## 4. Use of Estimates and Judgments

The corporation makes certain estimates and assumptions regarding the future. Estimates and judgments 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 medical and insurance 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. See Note 17 Employee Future Benefits.

Payments in Lieu of Taxes Payable and Deferred Taxes

The corporation is required to make payments in lieu of tax calculated on the same basis as income taxes on taxable income earned and capital taxes. Significant judgment is required in determining the provision for income taxes and deferred taxes. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The corporation recognizes liabilities for anticipated tax audit issues based on the corporation'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.

Accounts Receivable Impairment

In determining the allowance for doubtful accounts, the corporation considers historical loss experience of account balances based on the aging and arrears status of accounts receivable balances.

Estimate of Useful Life of Assets

The estimates and assumptions made to determine the useful life of property, plant and equipment and certain intangibles are determined by management at the time the asset is acquired and reviewed annually for appropriateness based on industry standards, historical experience, and technological obsolescence.

Regulatory Estimates

Certain estimates are necessary given that the regulatory environment in which the corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, pursuant to subsequent OEB regulatory proceedings or decisions.

Notes to Financial Statements (expressed in CDN$)

## 5. Seasonality

The corporation's operations are seasonal. The corporation's revenues tend to be higher in the first and third quarters of a year as a result of higher energy consumption for winter heating in the first quarter and air conditioning and cooling in the third quarter. The volume of electricity consumed by customers during any period is governed by events largely outside of the corporation's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

## 6. Cash and Bank

The corporation's bank account is held at one chartered bank and earns interest based upon its average monthly credit balance. Interest is paid monthly at the bank's monthly average prime rate less 1.70%. As at December 31, 2017 the rate was 1.50% (December 31, 2016 - 1.00%).

## 7. Accounts Receivable

| | **2017** | 2016 |
|---|---|---|
| Accounts receivable | **$ 3,400,410** | $ 3,978,432 |
| Other accrued and miscellaneous receivable | **162,471** | 172,390 |
| Construction and trade receivable | **524,133** | 414,573 |
| HST receivable | **118,878** | 160,477 |
| Collus PowerStream Solutions Corp. | **105,870** | 200,022 |
| | **4,311,762** | 4,925,894 |
| Less: Allowance for bad debts (See Note 24) | **96,615** | 75,016 |
| | **$ 4,215,147** | $ 4,850,878 |

Accounts receivable include $823,557 (December 31, 2016 - $752,890) for water and sewer billings.

**Notes to Financial Statements (expressed in CDN$)**

## 8. Payments in Lieu of Corporate Taxes

(a) The significant components of the provision for payments in lieu of taxes recognized in net income are as follows:

| | 2017 | 2016 |
|---|---|---|
| **Current tax** | | |
| Based on current year taxable income | **$ 138,233** | $ 150,279 |
| **Deferred tax** | | |
| Origination and reversal of temporary differences | **118,442** | 145,543 |
| | **$ 256,675** | $ 295,822 |

The significant components of the tax effect of the amount recognized in other comprehensive income are composed of:

| | 2017 | 2016 |
|---|---|---|
| **Deferred tax** | | |
| Remeasurement of defined benefit plan | **$ -** | $ (24,891) |

Statutory Canadian federal and provincial tax rates for the current year comprise 15% (2016 - 15%) for federal corporate tax and 11.5% (2016 - 11.5%) for corporate tax in Ontario. The PILs expense varies from amounts which would be computed by applying the corporation's combined statutory income tax rate as follows:

| | 2017 | 2016 |
|---|---|---|
| Total income and other comprehensive income | **$ 999,082** | $ 743,712 |
| Plus current and deferred income taxes | **256,675** | 270,931 |
| Net income before income taxes | **1,255,757** | 1,014,643 |
| Statutory Canadian federal and provincial tax rate | **26.50%** | 26.50% |
| Provision for PILs at statutory rate | **$ 332,776** | $ 268,880 |
| Increase (decrease) in income tax resulting from: | | |
| Reassessment 2012 | **-** | 5,041 |
| Interest and penalties on taxes | **-** | 333 |
| Temporary differences | **(67,083)** | 10,516 |
| Meals and entertainment | **1,272** | 1,271 |
| Co-operative education and apprenticeship credits | **(10,290)** | (16,174) |
| Taxable gain and net capital losses | **-** | 1,453 |
| Miscellaneous other | **-** | 708 |
| Investment income | **-** | 585 |
| Dividend tax credit | **-** | (1,682) |
| Total provision | **$ 256,675** | $ 270,931 |
| Effective tax rate | **20.44%** | 26.70% |

Notes to Financial Statements (expressed in CDN$)

**8. Payments in Lieu of Corporate Taxes Continued**

(b) The movement in the deferred tax asset is as follows:

| | | 2017 | | 2016 |
|---|---|---|---|---|
| Opening balance, January 1 | $ | **560,930** | $ | 681,582 |
| Recognized in net income | | **(118,442)** | | (145,543) |
| Recognized in other comprehensive income | | **-** | | 24,891 |
| Closing balance, December 31 | **$** | **442,488** | $ | 560,930 |

Deferred tax assets are attributable to the following:

| | | | | |
|---|---|---|---|---|
| Employee future benefits | **$** | **223,748** | $ | 222,294 |
| Property, plant and equipment | | **199,160** | | 312,063 |
| Goodwill | | **19,580** | | 26,573 |
| | **$** | **442,488** | $ | 560,930 |

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 corporation believes that this asset should be recognized as it will be recovered through future services.

Notes to Financial Statements (expressed in CDN$)

## 9. Property, Plant and Equipment

| | Land and Buildings | Distribution Equipment | Vehicles | Other Equipment | Work-in Progress | Total |
|---|---|---|---|---|---|---|
| **COST** | | | | | | |
| **January 1, 2016** | **$ 862,083** | **$ 15,773,145** | **$ 1,139,725** | **$ 577,338** | **$ 829,856** | **$ 19,182,147** |
| Additions | - | 3,737,887 | 354,140 | 86,911 | (482,594) | 3,696,344 |
| Disposals | (106,886) | (69,254) | - | (1,503) | - | (177,643) |
| **December 31, 2016** | **755,197** | **19,441,778** | **1,493,865** | **662,746** | **347,262** | **22,700,848** |
| Additions | - | 2,965,810 | 388,938 | 92,481 | 101,520 | 3,548,749 |
| Disposals | - | (29,078) | (49,172) | - | (7,149) | (85,399) |
| **December 31, 2017** | **$ 755,197** | **$ 22,378,510** | **$ 1,833,631** | **$ 755,227** | **$ 441,633** | **$ 26,164,198** |
| **ACCUMULATED AMORTIZATION** | | | | | | |
| **January 1, 2016** | **$ 18,631** | **$ 1,328,587** | **$ 451,515** | **$ 142,482** | **$ -** | **$ 1,941,215** |
| Amortization | 9,399 | 706,284 | 224,957 | 94,549 | - | 1,035,189 |
| Disposals | - | (11,080) | - | (786) | - | (11,866) |
| Impairment Loss | - | - | - | - | - | - |
| **December 31, 2016** | **28,030** | **2,023,791** | **676,472** | **236,245** | **-** | **2,964,538** |
| Amortization | 9,373 | 782,588 | 227,795 | 107,623 | - | 1,127,379 |
| Disposals | - | (10,292) | (49,172) | - | - | (59,464) |
| **December 31, 2017** | **$ 37,403** | **$ 2,796,087** | **$ 855,095** | **$ 343,868** | **$ -** | **$ 4,032,453** |
| **CARRYING AMOUNTS** | | | | | | |
| **December 31, 2016** | **$ 727,167** | **$ 17,417,987** | **$ 817,393** | **$ 426,501** | **$ 347,262** | **$ 19,736,310** |
| **December 31, 2017** | **$ 717,794** | **$ 19,582,423** | **$ 978,536** | **$ 411,359** | **$ 441,633** | **$ 22,131,745** |

During the year, the corporation capitalized borrowing costs, related to the duration of capital construction projects greater than four months, amounting to $NIL (2016 - $NIL).

**Notes to Financial Statements (expressed in CDN$)**

## 10. Intangibles

| | Paid Capital Contributions | Software | Goodwill | Total |
|---|---|---|---|---|
| **COST** | | | | |
| **January 1, 2016** | **$ -** | **$ 108,496** | **$ 276,704** | **$ 385,200** |
| Additions | 553,415 | 69,340 | - | 622,755 |
| Disposals | - | (5,035) | - | (5,035) |
| **December 31, 2016** | **553,415** | **172,801** | **276,704** | **1,002,920** |
| Additions | - | 13,999 | - | 13,999 |
| Disposals | - | (11,360) | - | (11,360) |
| **December 31, 2017** | **$ 553,415** | **$ 175,440** | **$ 276,704** | **$ 1,005,559** |
| **ACCUMULATED AMORTIZATION** | | | | |
| **January 1, 2016** | **$ -** | **$ 41,220** | **$ -** | **$ 41,220** |
| Additions | - | 26,705 | - | 26,705 |
| Disposals | - | (1,007) | - | (1,007) |
| **December 31, 2016** | **-** | **66,918** | **-** | **66,918** |
| Additions | 6,149 | 33,688 | - | 39,837 |
| Disposals | - | (11,360) | - | (11,360) |
| **December 31, 2017** | **$ 6,149** | **$ 89,246** | **$ -** | **$ 95,395** |
| **CARRYING AMOUNTS** | | | | |
| **December 31, 2016** | **$ 553,415** | **$ 105,883** | **$ 276,704** | **$ 936,002** |
| **December 31, 2017** | **$ 547,266** | **$ 86,194** | **$ 276,704** | **$ 910,164** |

**Notes to Financial Statements (expressed in CDN$)**

## 11. Regulatory Deferral Accounts

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. Where no recovery period is noted, the deferral amount will be applied for disposition at the time of the next Cost of Service Application to the OEB. The recovery period will be determined by the OEB at that time.

Due to previous, existing or expected future regulatory articles or decisions, the corporation has the following amounts expected to be recovered from customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

| | 2016 | Disposition May 2017 | Balances Arising in the Period | Recovery | 2017 |
|---|---|---|---|---|---|
| **Regulatory deferral debits:** | (Note 12) | | | | |
| Stranded assets | $ 527,592 | $ - | $ 6,154 | $ - | **$ 533,746** |
| OEB Cost assessment variance | 27,817 | - | 39,321 | - | **67,138** |
| Energy East consultation costs | 2,315 | - | 27 | - | **2,342** |
| IFRS transition costs | 201,286 | - | 2,272 | - | **203,558** |
| Late payment penalty settlement | (2,217) | - | - | - | **(2,217)** |
| Green Energy Renewable Connection | 8,711 | - | 3,985 | - | **12,696** |
| Stranded meters | 9,891 | - | 44 | - | **9,935** |
| Smart Grid | 4,711 | - | 54 | - | **4,765** |
| MIST Meters | - | - | 1,907 | - | **1,907** |
| PILs tax variance - Ontario SBD | 35,572 | - | 420 | - | **35,992** |
| LRAMVA | 103,540 | - | 42,377 | - | **145,917** |
| RARA approved May 1, 2013, 2 yr | 99,818 | - | 1,290 | - | **101,108** |
| RARA approved May 1, 2015, 1 yr | 161,767 | - | 1,714 | - | **163,481** |
| RARA approved May 1, 2010, 4 yr | 50,477 | - | 585 | - | **51,062** |
| Retail settlement variances | 1,340,692 | - | 336,389 | - | **1,677,081** |
| | 2,571,972 | - | 436,539 | - | **3,008,511** |
| Miscellaneous deferred debits | 115,064 | - | (66,159) | - | **48,905** |
| | $ 2,687,036 | $ - | $ 370,380 | $ - | **$3,057,416** |
| **Regulatory deferral credits:** | | | | | |
| RARA approved May 1, 2012, 2 yr | 12,075 | - | (76) | - | **11,999** |
| | $ 12,075 | $ - | $ (76) | $ - | **$ 11,999** |
| **Net regulatory asset** | $ 2,674,961 | $ - | $ 370,456 | $ - | **$3,045,417** |

Notes to Financial Statements (expressed in CDN$)

**11. Regulatory Deferral Accounts Continued**

Carrying charges are calculated monthly on the opening balance of the applicable variance account using the prescribed interest rate set by the OEB. During the year the corporation recorded a net debit balance of $36,692 (2016 - $5,829) to the above regulatory accounts for carrying charges and the related net credit balance is included in net movement on regulatory deferral accounts. The prescribed interest rate history is as follows:

| | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| 2017 OEB quarterly prescribed interest rates | 1.10 % | 1.10 % | 1.10 % | 1.50 % |
| 2016 OEB quarterly prescribed interest rates | 1.10 % | 1.10 % | 1.10 % | 1.10 % |

**Stranded Assets**

The purpose of this other regulatory deferral account is to record the cost of Sensus ICON model F and model G smart meters net of their accumulated amortization that must be removed from service prematurely before the end of their expected service life and replaced with new meters. These meters are exhibiting communication issues that are causing severe operational issues and are unable to meet new requirements such as data encryption. No amortization expense is recorded on these meters after they have been removed from service. Carrying charges are recorded monthly on the opening principal balance. A total of 4,631 units were replaced between June 2013 and December 31, 2015 at an actual removed net book value of $512,493.

**OEB Cost Assessment Variance**

On February 9, 2016, the Board established this deferral account to record material differences between the quarterly OEB cost assessments currently built into rates and the cost assessments that will result from the application of the new Cost Assessment Model.

**Energy East Consultation Costs**

On June 13, 2014, the Board established this deferral account to record the Energy East Pipeline Project consultation costs.

**IFRS Transition Costs**

The corporation uses this deferral account to record one-time administrative incremental IFRS transition costs, which are not already approved and included for recovery in distribution rates and the associated carrying charges.

**Late Payment Penalty ("LPP") Settlement**

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action. As its share of this settlement, the corporation was required to pay $46,486 on June 30, 2011 to charity to assist low income electricity users. The corporation received approval from the OEB to recover this amount from ratepayers over a one-year period, starting May 1, 2011.

**Green Energy Renewable Connection**

Under the Green Energy and Green Economy Act, electricity distributors are required to facilitate the connection of renewable energy sources to their systems and to undertake activities that will lead to a smart grid. The OEB has authorized deferral accounts to record the associated costs and related carrying charges.

**Notes to Financial Statements (expressed in CDN$)**

**11. Regulatory Deferral Accounts Continued**

**Stranded Meters**

This account includes the NBV of stranded mechanical meters, which have been replaced by smart meters, plus carrying charges and less rate rider recoveries beginning October 1, 2013 and ending April 30, 2015.

**Smart Grid**

Investments related to smart grid demonstration projects and investments undertaken as part of a project to accommodate renewable generation are recorded in the capital deferral account. Operating expenses directly related to smart grid development activities are recorded in the operating deferral account. Both of these deferral accounts attract applicable carrying charges.

**MIST (Metering Inside the Settlement Timeframe) Meters**

This meter cost deferral account has been established for the tracking of incremental capital, operating costs, and carrying charges related to the Distribution System Code amendment requiring distributors to install interval meters (i.e. MIST meters) on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50kW.

**Payments in Lieu of Taxes ("PILs") Variances - Other**

The PILs variance relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model. The OEB approved the disposition of a credit balance of $250,601 representing principal and interest to April 30, 2012, over a two year period from May 1, 2012 to April 30, 2014.

**Payments in Lieu of Taxes ("PILs") Variances - Ontario Small Business Deduction (SBD)**

Effective for taxation years ending after May 1, 2014, Canadian Controlled Private Corporations with taxable capital of $15 million or more are no longer eligible for the Ontario Small Business Deduction, which is a preferential corporate income tax rate of 4.5% instead of 11.5% on the first $500,000 of active business income. The Board requires any tax changes to be shared equally between ratepayers and the shareholder. The tax change was incorporated into the Incentive Regulation Mechanism ("IRM") with effective rates May 1, 2016.

| | | |
|---|---|---|
| 2014 Impact on Corporate Tax Return | $500,000 x (11.5% - 4.5%) = | $35,000 |
| 2015 Impact on Corporate Tax Return | $500,000 x (11.5% - 4.5%) = | $35,000 |
| | | $70,000 |
| | 50% sharing of tax change | x 50% |
| | | $35,000 |
| | Carrying charges | 992 |
| | | $35,992 |

**Notes to Financial Statements (expressed in CDN$)**

## 11. Regulatory Deferral Accounts Continued

### Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")

This variance account captures the difference between results of actual, verified impacts of authorized CDM activities undertaken and the level of CDM program activities included in the distributor's load forecast and therefore embedded into rates.

### Regulatory Asset Recovery Accounts ("RARA")

The RARA is comprised of the cumulative balances of regulatory assets and regulatory liabilities approved for disposition by the OEB, reduced by amounts settled with customers through billing of approved disposition rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and rates. The number of years over which the recovery has been approved has been noted in the preceding schedule.

### Retail Settlement Variance Accounts ("RSVA")

RSVAs are comprised of the variances between amounts charged by the corporation to its customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the corporation. The settlement variances relate primarily to service charges, non-competitive electricity charges and the global adjustment. Accordingly, the corporation has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB's direction.

### Low Voltage Variance

This account is included in Retail Settlement Variances and is used to record the variances arising from low voltage transactions that are not part of the electricity wholesale market.

### Other Regulatory Assets - Miscellaneous Deferred Debits

The following regulatory group of accounts tracks deferred costs for items that will be included in the expenses of other fiscal periods for purposes of developing the rates that the utility is authorized to charge:

| | **2017** | | | 2016 | | |
|---|---|---|---|---|---|---|
| | **Cost** | **Expensed** | **Net Book Value** | Cost | Expensed | Net Book Value |
| Regulatory expenses | **$ 346,356** | **$ 346,356** | **$ -** | $ 346,356 | $ 318,936 | $ 27,420 |
| Distribution system plan | **53,856** | **53,856** | **-** | 30,579 | - | 30,579 |
| Expansion charges | **204,914** | **156,009** | **48,905** | 204,914 | 147,849 | 57,065 |
| | **$ 605,126** | **$ 502,365** | **$ 48,905** | $ 581,849 | $ 466,785 | $ 115,064 |

Regulatory expenses included 2013 cost of service application expenses, which were charged to expense over the four year term of the application ending April 30, 2017. The distribution system plan is currently complete and has been fully expensed in 2017. Expansion charges includes expenses incurred in the expansion of the service area for Stayner, Creemore, and Thornbury, which will benefit future periods and are carried forward and charged to amortization expense over a twenty-five year period ending December 31, 2024.

**Notes to Financial Statements (expressed in CDN$)**

## 11. Regulatory Deferral Accounts Continued

The entry required to translate the accounting records from regulatory reporting to IFRS was as follows:

| | **2017** | 2016 |
|---|---|---|
| Statement of Comprehensive Income: | | |
| Decrease in the gross margin on sale of energy | **$ 315,826** | $ 335,221 |
| Decrease in distribution revenue | **40,831** | 50,238 |
| Decrease in operating expenses | **(14,012)** | (2,140) |
| Increase in interest expense | **35,971** | 5,829 |
| Decrease in amortization | **(5,040)** | (8,160) |
| Balance Sheet: | | |
| Increase in property, plant and equipment | **90,491** | - |
| Decrease to regulatory deferral accounts | **(93,611)** | - |
| Net movement on regulatory deferral accounts | **370,456** | 380,988 |
| RSVA regulatory balance adjustment (Note 12 a) | **-** | 901,605 |
| Increase in retained earnings | **2,674,961** | 1,392,368 |
| | **$ 3,045,417** | $ 2,674,961 |

## 12. Restatement

Certain comparative figures have been restated for 2016 as follows:

(a) The OEB ordered the corporation to engage a special purpose audit of its regulatory deferral balances for RSVA Power and Global Adjustment for the years 2014 to 2016 and an adjustment was required.

(b) The corporation discovered an error within the metering and billing set up at a plant owned by The Town of Collingwood and repaid two years of overbilling.

(c) The corporation corrected its understanding of IFRS 14 Regulatory Deferral Accounts in relation to the presentation of deferred taxes.

| <u>Balance Sheet:</u> | **Original** | **(a)** | **(b)** | **(c)** | **Restated** |
|---|---|---|---|---|---|
| Regulatory deferral net | $ 1,043,525 | $ 901,605 | $ 168,901 | $ 560,930 | $ 2,674,961 |
| Accounts payable | (7,688,912) | (901,605) | (168,901) | - | (8,759,418) |
| OCI | 152,567 | - | - | (24,891) | 127,676 |
| Retained earnings | (1,574,153) | - | - | (536,039) | (2,110,192) |
| <u>Income Statement:</u> | | | | | |
| Sale of energy | 36,500,735) | - | 184,054 | - | 36,316,681) |
| Cost of Power | 36,667,055 | - | (15,153) | - | 36,651,902 |
| Regulatory movement | (357,630) | - | (168,901) | 145,543 | (380,988) |
| Regulatory movement OCI | 24,891 | - | - | (24,891) | - |

## Notes to Financial Statements (expressed in CDN$)

### 13. Accounts Payable and Accruals

| | 2017 | 2016 |
|---|---|---|
| Independent Electricity System Operator | **$ 3,180,964** | $ 4,880,061 |
| Hydro One | **762,568** | 795,110 |
| Trade payables | **725,534** | 929,027 |
| Town of Collingwood - Sewer | **1,300,413** | 1,137,903 |
| Town of Collingwood - Water | **730,452** | 638,157 |
| Economic evaluations | **66,989** | 66,989 |
| Debt retirement charge payable | **78,121** | 87,801 |
| Other accounts payable and accruals | **103,367** | 66,282 |
| Accrued interest on long-term debt | **28,502** | 30,775 |
| Deferred conservation program funding | **99,143** | 127,313 |
| | **$ 7,076,053** | $ 8,759,418 |

### 14. Customer Deposits and Credits

| | 2017 | 2016 |
|---|---|---|
| Customer deposits | **$ 453,000** | $ 480,169 |
| Construction work deposits | **104,651** | 96,146 |
| Customer credit balances in trade receivables | **342,250** | 301,121 |
| | **899,901** | 877,436 |
| Less long-term portion of customer deposits | **265,077** | 278,020 |
| | **$ 634,824** | $ 599,416 |

### 15. Contributions in Aid of Construction

| | 2017 | 2016 |
|---|---|---|
| Deferred contributions, net, beginning of year | **$ 2,769,851** | $ 1,075,897 |
| Contributions in aid of construction received | **527,957** | 1,739,589 |
| Contributions in aid of construction recognized as other revenue | **(72,285)** | (45,635) |
| Deferred contributions, net, end of year | **$ 3,225,522** | $ 2,769,851 |

**Notes to Financial Statements (expressed in CDN$)**

## 16. Long-term Debt

| | **2017** | 2016 |
|---|---|---|
| Infrastructure Ontario Debentures - secured by a general security agreement on all assets and real property under a second charge equal priority ranking arrangement with TD | | |
| • 4.67% fixed rate, $100,000 principal repayable semi-annually plus interest in October and April, due April 2025 | **$ 1,500,000** | $ 1,700,000 |
| • 3.84% fixed rate, $32,700 principal and interest repayable monthly, due September 2037 | **5,426,279** | 5,606,535 |
| • 4.58% fixed rate, $3,563 principal and interest repayable monthly, due December 2043 | **651,933** | 664,778 |
| • 2.76% fixed rate, $25,000 principal repayable semi-annually plus interest in October and April, due April 2035 | **875,000** | 925,000 |
| TD Bank Debentures - secured by a general security agreement on all assets and real property under a second charge equal priority ranking arrangement with Infrastructure Ontario | | |
| • 3.65% fixed rate, $14,239 combined principal and interest repayable monthly, due December 31, 2025 | **2,994,024** | 3,054,417 |
| • 3.59% fixed rate, $14,077 combined principal and interest repayable monthly, due March 31, 2027 | **3,048,746** | - |
| | **14,495,982** | 11,950,730 |
| Current portion of long-term debt | **573,858** | 503,495 |
| | **$ 13,922,124** | $ 11,447,235 |

The agreement governing these facilities contains certain covenants as described in Note 28.

Principal repayments for each of the five subsequent years and thereafter are as follows:

| | |
|---|---|
| 2018 | $ 573,858 |
| 2019 | 586,334 |
| 2020 | 598,699 |
| 2021 | 612,727 |
| 2022 | 626,703 |
| Thereafter | 11,497,661 |
| | $ 14,495,982 |

Subsequent to year-end, in March 2018 the corporation received a $2,000,000 loan advance from TD bank.

## 17. Employee Future Benefits

(a) Pension plan

The employees of the corporation 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 plan specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund. The employer portion of amounts paid to OMERS during the year was $293,887 (2016 - $185,757). The contributions were made for current service and these have been recognized in net income.

Each year, an independent actuary determines the funding status of OMERS Primary Pension Plan by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2016. The results of this valuation disclosed total actuarial liabilities of $87.6 (2015 - $82.4) billion in respect of benefits accrued for service with actuarial assets at that date of $81.8 (2015 - $75.4) billion, indicating an actuarial deficit of $5.7 (2015 - $7.0) billion. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the corporation does not recognize any share of the OMERS pension surplus or deficit.

The contribution rates for normal retirement age 65 members were 9.0% (2016 - 9.0%) for employees earning up to $55,300 (2016 - $54,900) and 14.6% (2016 - 14.6%) thereafter.

(b) Post employment medical and life insurance plan

The corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. All employees who retire from the corporation are eligible for post-retirement life insurance benefits. In addition, employees age 55 or older with a minimum of 25 years of active service are eligible for extended health, dental, and vision benefits until they turn 65.

These benefits are provided through a group defined benefit plan. The corporation 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, 2017 and 2016 were based on results and assumptions determined by actuarial valuation as at December 31, 2016.

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.

Notes to Financial Statements (expressed in CDN$)

**17. Employee Future Benefits Continued**

Information about the group unfunded defined benefit plan as a whole and changes in the present value of the unfunded defined benefit obligation and the accrued benefit liability are as follows:

| | **2017** | 2016 |
|---|---|---|
| Defined benefit obligation, beginning of the year | **$ 838,844** | $ 381,933 |
| Amounts recognized in net income: | | |
| Current service cost | **22,708** | 6,793 |
| Interest cost on obligation | **31,760** | 17,814 |
| | **54,468** | 24,607 |
| Amounts recognized in other comprehensive income: | | |
| Actuarial loss from financial assumption | **-** | 93,928 |
| Benefit payments | **(48,981)** | (21,646) |
| Assumption of related company employee future benefits | **-** | 360,022 |
| Defined benefit obligation, end of the year | **$ 844,331** | $ 838,844 |

Actuarial assumptions are as follows:

| | **2017** | 2016 |
|---|---|---|
| Discount rate | **3.90 %** | 3.90 % |
| Consumer price index | **2.00 %** | 2.00 % |
| Rate of compensation increase | **3.50 %** | 3.50 % |
| Health benefits costs escalation | **4.50 % to 5.78 %** | 4.50 % to 5.99 % |
| Dental benefits costs escalation | **4.50 %** | 4.50 % |
| Retirement age | **59 yrs** | 59 yrs |

Sensitivity analysis for each significant actuarial assumption to which the corporation is exposed is as follows:

| | Discount Rate | | Retirement Age | | Health Benefits | |
|---|---|---|---|---|---|---|
| | 1%+ | 1%- | 2 yrs+ | 2 yrs- | 1%+ | 1%- |
| Obligation | $ (101,000) | $ 130,000 | $ (64,000) | $ 62,000 | $ 32,000 | $ (29,000) |
| Service Cost | (5,000) | 7,000 | (4,000) | 4,000 | 4,000 | (3,000) |
| Interest Cost | 3,000 | (5,000) | (3,000) | 2,000 | 1,000 | (2,000) |

The weighted average duration of the defined benefit obligation at December 31, 2017 was 14 years (December 31, 2016 - 14 years).

Notes to Financial Statements (expressed in CDN$)

## 18. Share Capital

(a) Ordinary shares: The authorized share capital of the corporation is an unlimited number of common shares. The shares have no par value. All shares are ranked equally with regard to the corporation's residual assets. There are no preference shares. The issued and fully paid share capital is as follows:

| | | 2017 | 2016 |
|---|---|---|---|
| 5,101,340 | Common shares | **$ 5,101,340** | $ 5,101,340 |

(b) Movement in ordinary share capital: No movement in ordinary share capital has occurred during 2017 or 2016.

## 19. Miscellaneous Paid In Capital

Collingwood Public Utilities Commission was restructured November 1, 2000. The Ontario Government enacted the Energy Competition Act, 1998 which introduced competition to the Ontario electricity market. Net electricity distribution assets and liabilities of the original Collingwood Public Utilities Commission were transferred to the newly created corporations on November 1, 2000.

| | |
|---|---|
| Net assets & liabilities | $ 9,777,524 |
| Promissory note - Town of Collingwood | (1,710,170) |
| Common shares | (5,101,340) |
| Miscellaneous Paid In Capital | $ 2,966,014 |

## 20. Dividends

Dividends in the amount of $NIL (2016 - $122,998) were declared and paid to Collingwood PowerStream Utility Services Corp. (See Note 26).

The amount of dividends declared in any given year is at the discretion of the Board of Directors of the corporation. The dividend policy states that the corporation shall normally pay a minimum of 50% of the prior year annual net income, as dividends, with consideration given to the cash position, working capital, net capital expenditures, and other cash requirements.

## 21. Liability Insurance

The corporation belongs to the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2017, the corporation has not been made aware of any assessments for losses. Insurance premiums charged to each member consist of a levy per thousand of dollars of service revenue subject to a credit or surcharge based on each member's claims experience.

**Notes to Financial Statements (expressed in CDN$)**

## 22. Credit Facilities

The credit facility agreement contains certain covenants as described in Note 28.

Line of Credit

The corporation has a line of credit, secured by a general security agreement, with an authorized limit of $500,000 available under a credit facility agreement with a Canadian chartered bank. Interest on advances is calculated using the bank's prime rate less 0.30% per annum, calculated and payable monthly. As at December 31, 2017 the balance was $NIL (2016 - $NIL) on this credit facility and the rate was 3.20% (2016 - 2.70%).

Letter of Credit ("LOC")

As at December 31, 2017, the corporation had utilized $2,326,160 (2016 - $2,326,160) of the $2,417,179 uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. The IESO could draw on the LOC if the corporation defaults on its payment. The standby LOC fee is charged annually at a rate of 0.50% (2016 - 0.50%). For the year ended December 31, 2017 the fee incurred was $11,631 (2016 - $11,631).

Credit Card

The corporation has a VISA account, secured by a general security agreement, with an authorized limit of $25,000 available under a credit facility agreement with a Canadian chartered bank.

## 23. Amortization

| | **2017** | 2016 |
|---|---|---|
| Property, plant and equipment | **$ 1,127,379** | $ 1,035,187 |
| Less vehicle amortization, burdened to other accounts | **(227,795)** | (224,957) |
| | **899,584** | 810,230 |
| Capital contributions paid | **6,149** | - |
| Software | **33,688** | 26,705 |
| Deferred charges | **8,160** | 8,160 |
| | **947,581** | 845,095 |
| Less net regulatory movement related to deferred charges | **(8,160)** | (8,160) |
| | **939,422** | 836,935 |

Notes to Financial Statements (expressed in CDN$)

## 24. Bad Debt Expense (Included in Billing and Collecting)

| | **2017** | 2016 |
|---|---|---|
| Write-offs during the year | **$ 82,725** | $ 74,862 |
| Recoveries during the year | **(26,895)** | (13,580) |
| Opening allowance | **(75,016)** | (77,916) |
| Closing allowance | **96,615** | 75,016 |
| | **$ 77,429** | $ 58,382 |

## 25. Finance Income and Finance Cost

| | **2017** | 2016 |
|---|---|---|
| **Finance Income:** | | |
| Interest earned on bank account | **$ 40,051** | $ 32,790 |
| **Finance Cost:** | | |
| Net interest on employee future benefits | **$ 31,760** | $ 17,814 |
| Interest on customer deposits | **14,360** | 3,354 |
| Interest on Letter of Credit | **11,631** | 11,695 |
| Interest on long-term debt | **542,006** | 472,483 |
| Interest other | **-** | 1,258 |
| | **$ 599,757** | $ 506,604 |

## 26. Related Party Transactions

(a) The ultimate parent

Collingwood PowerStream Utility Services Corp. (owned 50% by the Town of Collingwood and 50% by Alectra Utilities Corporation) is the holding company for the following three wholly-owned subsidiaries:

(i) Collus PowerStream Corp. - Electricity distributor
(ii) Collus PowerStream Solutions Corp. - Inactive as of January 1, 2017
(iii) Collus PowerStream Energy Corp. - Inactive

Since the ultimate parent constitutes local government, the corporation 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.

Notes to Financial Statements (expressed in CDN$)

## 26. Related Party Transactions Continued

(b) Transactions with related parties

The following summarizes the corporation's related party transactions for the year. These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product or provision of service.

| | 2017 | | | | |
|---|---|---|---|---|---|
| | 50% Share-holder of Parent | 50% Share-holder of Parent | Parent | Wholly owned subsidiary of Parent | Wholly owned subsidiary of Parent |
| | Town of Collingwood | Alectra | Collingwood PowerStream Utility Services Corp. | Collus PowerStream Solutions Corp. | Collus PowerStream Energy Corp. |
| **Receipts:** | | | | | |
| Shared employees - billing & collecting | $ 260,000 | $ | $ | $ | $ |
| Shared invoices - billing & collecting | 245,572 | | | | |
| Subcontract recoverable work | 57,146 | | | | |
| Information technology services | 49,240 | | | | |
| Streetlight maintenance | 27,077 | | | | |
| | $ 639,035 | $ | $ | $ | $ |
| **Disbursements:** | | | | | |
| Property taxes | $ 16,051 | $ | $ | $ | $ |
| Property maintenance | 5,000 | | | | |
| Board payments | 3,000 | 1,200 | | | |
| Services | | 45,126 | | | |
| Shared employee charge | 30,733 | 121,509 | | | |
| Building lease | 216,000 | | | | |
| Conservation program | | 13,001 | | | |
| Misc and shared invoices | 3,664 | | | | |
| Inventory and capital materials | | 362 | | | |
| | $ 274,448 | $ 181,198 | $ | $ | $ |
| **Dividends paid** | $ | $ | $ | $ | $ |

Notes to Financial Statements (expressed in CDN$)

## 26. Related Party Transactions Continued

| | 2016 | | | | |
|---|---|---|---|---|---|
| | 50% Share-holder of Parent | 50% Share-holder of Parent | Parent | Wholly owned subsidiary of Parent | Wholly owned subsidiary of Parent |
| | Town of Collingwood | PowerStream Inc. | Collingwood PowerStream Utility Services Corp. | Collus PowerStream Solutions Corp. | Collus PowerStream Energy Corp. |
| **Receipts:** | | | | | |
| Shared employee services | $ | $ | $ | $ 181,183 | $ |
| Streetlight maintenance | 41,638 | | | | |
| Conservation funding from IESO | | 40,000 | | | |
| Emergency assistance | | 12,999 | | | |
| | $ 41,638 | $ 52,999 | $ | $ 181,183 | $ |
| **Disbursements:** | | | | | |
| Property taxes | $ 18,662 | $ | $ | $ | $ |
| Property maintenance | 5,000 | | | | |
| Board payments | 2,100 | | | | |
| Services | | 20,973 | | | |
| Shared employee charge | 43,331 | 143,291 | | 694,586 | |
| Computer lease | 21,792 | | | | |
| Building lease | 216,000 | | | | |
| Conservation program | | 12,750 | | | |
| Misc and shared invoices | 13,812 | 1,960 | | | |
| Emergency assistance | | 5,796 | | | |
| Inventory and capital materials | | 36,394 | | | |
| | $ 320,697 | $ 221,164 | $ | $ 694,586 | $ |
| **Dividends paid** | $ | $ | $ 122,998 | $ | $ |

## Notes to Financial Statements (expressed in CDN$)

### 26. Related Party Transactions Continued

At the end of the year, the amounts due from and due (to) related parties are as follows:

| | 2017 | | | | |
|---|---|---|---|---|---|
| | 50% Share-holder of Parent | 50% Share-holder of Parent | Parent | Wholly owned subsidiary of Parent | Wholly owned subsidiary of Parent |
| | Town of Collingwood | Alectra | Collingwood PowerStream Utility Services Corp. | Collus PowerStream Solutions Corp. | Collus PowerStream Energy Corp. |
| Trade receivable | $ 65,550 | $ 14,689 | $ | $ 105,870 | $ |
| Trade payable | | (1,766) | | | |
| Utility payable | (410,748) | | | | |
| Waste water collections payable | (1,300,413) | | | | |
| Water collections payable | (730,452) | | | | |
| | $ (2,376,063) | $ 12,923 | $ | $ 105,870 | $ |

| | 2016 | | | | |
|---|---|---|---|---|---|
| Trade receivable | $ 85,426 | $ 14,689 | $ | $ 200,022 | $ |
| Trade payable | (24,883) | (18,049) | | | |
| Interest payable | | | | | |
| Waste water collections payable | (1,137,903) | | | | |
| Water collections payable | (638,157) | | | | |
| | $ (1,715,517) | $ (3,360) | $ | $ 200,022 | $ |

(c) The key management personnel compensation is comprised of the corporation's board of directors and management team.

| | **2017** | 2016 |
|---|---|---|
| Board of directors' fees | **$ 48,369** | $ 49,992 |
| Short-term employment benefits and salaries | **967,927** | 899,824 |
| | **$ 1,016,296** | $ 949,816 |

**Notes to Financial Statements (expressed in CDN$)**

## 27. Financial Instruments

The corporation's carrying value and fair value of financial instruments consist of the following:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| | **Carrying Amount** | **Fair Value** | Carrying Amount | Fair Value |
| **Assets** | | | | |
| Cash and bank | **$ 2,255,077** | **$ 2,255,077** | $ 940,680 | $ 940,680 |
| Accounts receivable | **4,215,147** | **4,215,147** | 4,850,878 | 4,850,878 |
| Unbilled energy revenue | **3,863,870** | **3,863,870** | 4,852,979 | 4,852,979 |
| **Liabilities** | | | | |
| Accounts payable & accruals | **$ 7,076,053** | **$ 7,076,053** | $ 8,759,418 | $ 8,759,418 |
| Customer deposits | **899,901** | **899,901** | 877,436 | 877,436 |
| Long-term debt | **14,495,982** | **14,495,982** | 11,950,730 | 11,950,730 |

The estimated fair values of financial instruments as at December 31, 2017 and December 31, 2016 are based on relevant market prices and information available at the time. The fair value estimates are not necessarily indicative of the amounts that the corporation may receive or incur in actual market transactions. These estimates are subjective in nature and involve uncertainties and matters of significant judgment and therefore cannot be determined with precision. Changes in assumptions could significantly affect the estimates.

**Determination of fair values**

(a) The fair values of cash and bank, accounts receivable, unbilled energy revenue, current customer deposits and credit balances, and accounts payable and accruals approximate their carrying values because of the short-term nature of these instruments.

(b) The fair value of each of the corporation's long-term debt instruments is based on the amount of future cash flows associated with each instrument discounted using an estimate of what the corporation's current borrowing rate for similar debt instruments of comparable maturity would be.

It is management's intention not to renew the long-term debt until its maturity.

Financial Instruments which are disclosed at fair value are to be classified using a three-level hierarchy. Each level reflects the inputs used to measure the fair values disclosed of the financial liabilities and are as follows:

- Level 1: Inputs are unadjusted quoted prices of identical instruments in active markets;

**Notes to Financial Statements (expressed in CDN$)**

## 27. Financial Instruments Continued

- Level 2: Inputs other than quoted prices included in Level 1 that are observable for the asset or liability either directly or indirectly; and
- Level 3: Inputs for the liabilities that are not based on observable market data (unobservable inputs)

The corporation's fair value hierarchy is classified as Level 2 for long-term debt. The classification has been calculated using the discounted cash flow model based on the contractual terms of the instrument discounted using an appropriate market rate of interest.

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## 28. Capital Disclosures

The corporation considers its capital to be its share capital, miscellaneous paid in capital, retained earnings and accumulated other comprehensive income. The corporation's main objectives when managing capital are to: i) ensure sufficient liquidity to maintain and improve its electricity distribution system, support its financial obligations and execute its operating and strategic plans, ii) minimize the cost of capital while taking into consideration current and future industry, market and economic risks and conditions, iii) maintain an optimal capital structure that provides necessary financial flexibility and considers recoveries of financing charges permitted by the OEB, while also ensuring compliance with any financial covenants, and iv) provide an adequate return to its shareholders.

The corporation relies on its cash flow from operations to fund its dividend distributions to its shareholders.

As part of existing debt agreements, financial covenants are monitored and communicated, as required by the terms of credit agreements, on an annual basis by management to ensure compliance with the agreements.

The covenants require the corporation to provide notification prior to any new debt issuance. All covenants are to be tested and calculated as of the end of each fiscal year. The corporation was in compliance with these covenants during the year and as at December 31, 2017.

Management monitors the following key ratios to effectively manage capital:

| | | **2017** | 2016 |
|---|---|---|---|
| a) Debt Service Coverage Ratio IO: | (must be at least 1.30) | **1.38**:**1** | 1.52:1 |
| b) Debt Service Coverage Ratio TD: | (must be at least 1.20) | **1.22**:**1** | 1.21:1 |
| d) Debt to Total Assets IO: | (must not exceed 0.60) | **0.39**:**1** | 0.34:1 |
| c) Debt to Capital TD: | (must not exceed 0.60) | **0.51**:**1** | 0.50:1 |
| e) Current ratio IO: | (must be at least 1.10) | **1.34:1** | 1.15:1 |

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Notes to Financial Statements (expressed in CDN$)

## 29. Financial Risk Management

As part of its operations, the corporation 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 corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.

(a) Credit risk

Credit risk is the risk that one party to a financial instrument will cause a loss for the other party by failing to pay for its obligation. The maximum credit exposure is limited to the carrying amount of cash and bank, accounts receivable, and unbilled energy revenue presented on the balance sheet.

The corporation limits its exposure to credit loss by placing its cash with a high credit quality financial institution. The corporation maintains cash with only one major financial institution. Eligible deposits per financial institution are insured to a maximum basic insurance level of $100,000, including principal and interest by the Canada Deposit Insurance Corporation.

The corporation is exposed to credit risk related to accounts receivable and unbilled energy revenue arising from its day-to-day electricity and service revenue. Exposure to credit risk is limited due to the corporation's large and diverse customer base. The corporation has approximately 17,000 customers, the majority of which are residential. No single customer accounts for revenue in excess of 10% of total revenue. The corporation limits its credit risk by collecting deposits (See Note 14), purchasing commercial account credit insurance, following collection policies, monitoring accounts receivable aging, and utilizing collection agencies. The Ontario Energy Board has prescribed certain rules for the payment of deposits by customers. Although these rules limit the risk of the corporation, no deposits are required by customers who have shown good payment history for the previous 24 month period. The corporation does not have any material accounts receivable balances greater than 90 days outstanding. The corporation believes that its accounts receivable represent a low credit risk.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in net income. The provision is based on account age and customer standing. Subsequent recoveries of receivables previously provisioned are credited to net income. (See Note 24)

The value of accounts receivable, by age, and the related bad debt provision are presented in the following table. Unbilled energy revenue which is not included in the table below is considered all current. Receivables greater than 30 days are considered past due.

| | **2017** | 2016 |
|---|---|---|
| Under 30 days | **$ 3,785,379** | $ 4,608,460 |
| 30 to 60 days | **91,144** | 171,114 |
| 61 to 90 days | **22,632** | 50,589 |
| Over 90 days | **412,607** | 95,731 |
| | **4,311,762** | 4,925,894 |
| Provision | **96,615** | 75,016 |
| Total accounts receivable | **$ 4,215,147** | $ 4,850,878 |

## Notes to Financial Statements (expressed in CDN$)

### 29. Financial Risk Management Continued

(b) Liquidity risk

Liquidity risk is the risk that the corporation will encounter difficulty in meeting obligations associated with financial liabilities. The corporation's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the corporation's reputation. The corporation's exposure is reduced by cash generated from operations and undrawn credit facilities. The corporation engages in borrowing to meet financing needs that exceed cash from operations. Exposure to such risks is significantly reduced through close monitoring of cash flows and budgeting. Liquidity risks associated with financial commitments are as follows:

| | 0 - 3 mo | 3 mo - 1 yr | 1 - 5 yr | Thereafter | Total |
|---|---|---|---|---|---|
| Accounts payable | $ 7,009,064 | $ 66,989 | $ - | $ - | $ 7,076,053 |
| Customer deposits/credits | - | 634,824 | 265,077 | - | 899,901 |
| Long-term debt | 80,564 | 493,294 | 2,424,463 | 11,497,660 | 14,495,981 |
| Total | $ 7,089,628 | $ 1,195,107 | $ 2,689,540 | $ 11,497,660 | $ 22,471,935 |

(c) Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the corporation's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits.

The corporation does not have any direct exposure to foreign currency exchange rate risk or commodity price risk. The corporation had no forward exchange rate contracts or commodity price contracts in place as at or during the year ended December 31, 2017.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Note 17 describes the interest rate risk associated with Employee Future Benefits. The corporation is also exposed to interest rate fluctuations on its cash and bank and undrawn bank credit facilities. The corporation is protected from interest rate fluctuations on long-term debt for Infrastructure Ontario and TD Bank loans, which bear fixed rates of interest. As at December 31, 2017, if interest rates had been 1% lower or higher with all other variables held constant, net income for the year would not have been impacted materially.

**Notes to Financial Statements (expressed in CDN$)**

## 30. Expenses by Nature

| | | **2017** | 2016 |
|---|---|---|---|
| **Billing and collecting:** | | | |
| After hours call centre | | **$ 15,865** | $ 15,521 |
| Bad debts | (Note 24) | **77,429** | 58,382 |
| Bank charges | | **17,660** | 16,027 |
| Billing supplies and services provided | | **154,566** | 150,401 |
| Collection agency costs | | **4,261** | 2,233 |
| Contingency | | **30,000** | - |
| Disconnection and collection service subcontractor | | **25,066** | 36,046 |
| Information technology | | **68,727** | 16,403 |
| Insurance - Business credit collections | | **22,138** | 21,760 |
| Meter reading - manual | | **11,431** | 10,120 |
| Office and general | | **16,835** | 8,167 |
| Postage | | **86,000** | 67,693 |
| Retail and settlement expenses | | **84,160** | 85,048 |
| Survey | | **8,859** | 9,700 |
| Salaries and benefits | | **347,196** | 320,937 |
| Smart meter reading and operations | | **213,081** | 227,790 |
| Telephone | | **1,977** | 2,246 |
| Training and travel | | **12,552** | 1,706 |
| Vehicle burden allocation | | **1,589** | 932 |
| | | **$ 1,199,392** | $ 1,051,112 |
| Add regulatory movement, smart meter reading | | **5,265** | 3,183 |
| | | **$ 1,204,657** | $ 1,054,295 |
| **Operations and maintenance:** | | | |
| Information technology | | **59,895** | - |
| Materials, supplies, small tools | | **$ 82,814** | $ 72,128 |
| Office and general | | **5,848** | 3,356 |
| Property taxes | | **19,817** | 22,082 |
| Rent - operations facility and yard | | **172,800** | 172,800 |
| Rent - joint pole use | | **26,256** | 20,790 |
| Salaries, benefits and burdens | | **1,394,358** | 1,677,799 |
| Subcontractor and service providers | | **199,198** | 195,531 |
| Telephone | | **11,700** | 13,850 |
| Training and travel | | **58,933** | 21,069 |
| Utilities | | **8,174** | 8,821 |
| Vehicle burden allocation | | **150,101** | 273,905 |
| | | **$ 2,189,894** | $ 2,482,131 |

**Notes to Financial Statements (expressed in CDN$)**

## 30. Expenses by Nature Continued

**General and administrative:**

| | **2017** | 2016 |
|---|---|---|
| Advertising and sponsorships | **$ 11,569** | $ 14,203 |
| Actuary | **-** | 7,757 |
| Audit | **41,115** | 33,000 |
| Bank charge - loan arrangement fee | **7,000** | - |
| Building maintenance | **2,466** | 393 |
| Computer lease | **-** | 21,792 |
| Conferences, events, training, meetings and travel | **45,069** | 31,626 |
| Consulting | **30,750** | 26,703 |
| Information technology | **64,971** | 30,201 |
| Insurance | **69,029** | 72,984 |
| Legal | **94,661** | 59,143 |
| Memberships, fees and dues | **99,974** | 102,203 |
| Office supplies and materials | **8,042** | 9,044 |
| Regulatory | **150,823** | 125,798 |
| Rent - administration building | **43,200** | 43,200 |
| Salaries and benefits | **516,235** | 774,442 |
| Telephone | **3,335** | 6,859 |
| | **$ 1,188,239** | $ 1,359,348 |
| Less regulatory movement, regulatory expenses | **(19,277)** | (24,113) |
| Less regulatory movement, audit | **-** | 18,789 |
| | **$ 1,168,962** | $ 1,354,024 |

## 31. Summary of Changes in Liabilities Arising from Financing Activities

| | **2016** | Proceeds | Repayment | Other | **2017** |
|---|---|---|---|---|---|
| Long-term customer deposits | $ 278,020 | $ | $ | $ (12,943) | $ 265,077 |
| Current and long-term debt | 11,950,730 | 3,100,000 | (554,749) | | 14,495,982 |
| Accrued interest* | 30,775 | | | (2,272) | 28,502 |
| | $ 12,259,525 | $ 3,100,000 | $ (554,749) | $ (15,215) | $ 14,789,561 |

* Accrued interest is included within accounts payable and accruals

**APPENDIX C:**
**December 31, 2017 Audited Financial Statements of EPCOR Utilities Inc.**

Consolidated Financial Statements of

# EPCOR UTILITIES INC.

Years ended December 31, 2017 and 2016

# Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of EPCOR Utilities Inc. are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to February 15, 2018. Financial information presented elsewhere is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that relevant financial information is reliable, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been audited by KPMG LLP, the Company's external auditors. The external auditors are responsible for auditing the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with International Financial Reporting Standards. The auditors' report outlines the scope of their audit and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee, which is composed of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and management's discussion and analysis and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Stuart Lee
President and Chief Executive Officer

Guy Bridgeman
Senior Vice President and Chief Financial Officer

February 15, 2018

# EPCOR UTILITIES INC.
Consolidated Financial Statements

Years ended December 31, 2017 and 2016

KPMG LLP
2200, 10175 101 St NW
Edmonton AB T5J 0H3
Telephone (780) 429-7300
Fax (780) 429-7379
www.kpmg.ca

# INDEPENDENT AUDITORS' REPORT

To the Shareholder of EPCOR Utilities Inc.

We have audited the accompanying consolidated financial statements of EPCOR Utilities Inc., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Consolidated Financial Statements*

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

*Auditors' Responsibility*

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

*Opinion*

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of EPCOR Utilities Inc. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants
February 15, 2018
Edmonton, Canada

# EPCOR UTILITIES INC.

Consolidated Statements of Comprehensive Income
(In millions of Canadian dollars)

Years ended December 31, 2017 and 2016

| | 2017 | 2016 |
|---|---|---|
| Revenues and other income: | | |
| Revenues (note 6) | $ 2,035 | $ 1,932 |
| Other income (note 6) | 12 | 14 |
| | 2,047 | 1,946 |
| Operating expenses: | | |
| Energy purchases and system access fees | 804 | 722 |
| Other raw materials and operating charges | 170 | 191 |
| Staff costs and employee benefits expenses (note 7) | 281 | 275 |
| Depreciation and amortization (note 7) | 236 | 189 |
| Franchise fees and property taxes | 112 | 99 |
| Other administrative expenses (note 7) | 88 | 91 |
| | 1,691 | 1,567 |
| Operating income | 356 | 379 |
| Finance expenses (note 8) | (115) | (112) |
| Fair value gain on available-for-sale investment in Capital Power reclassified from other comprehensive income (note 12) | 1 | 42 |
| Dividend income from available-for-sale investment in Capital Power | - | 9 |
| Income before income taxes | 242 | 318 |
| Income tax recovery (expense) (note 9) | 14 | (9) |
| Net income for the year – all attributable to the Owner of the Company | 256 | 309 |
| Other comprehensive income (loss): | | |
| Item that will not be reclassified to net income: | | |
| Re-measurements of net defined benefit plans | (5) | (1) |
| Items that have been or may subsequently be reclassified to net income: | | |
| Fair value gain on available-for-sale investment in Capital Power | - | 43 |
| Fair value loss on available-for-sale beneficial interest in sinking fund | (1) | - |
| Fair value gain on available-for-sale investment in Capital Power reclassified to net income | (1) | (42) |
| Unrealized loss on foreign currency translation | (30) | (11) |
| | (32) | (10) |
| | (37) | (11) |
| Comprehensive income for the year - all attributable to the Owner of the Company | $ 219 | $ 298 |

The accompanying notes are an integral part of these consolidated financial statements

# EPCOR UTILITIES INC.

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

December 31, 2017 and 2016

| | 2017 | 2016 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents (note 10) | $ 338 | $ 191 |
| Trade and other receivables (note 11) | 551 | 325 |
| Available-for-sale investment in Capital Power (note 12) | - | 6 |
| Derivatives (note 13) | 1 | - |
| Inventories (note 14) | 17 | 14 |
| | 907 | 536 |
| Non-current assets: | | |
| Other financial assets (note 15) | 91 | 265 |
| Deferred tax assets (note 16) | 90 | 84 |
| Property, plant and equipment (note 17) | 8,977 | 4,983 |
| Intangible assets and goodwill (note 18) | 293 | 293 |
| | 9,451 | 5,625 |
| TOTAL ASSETS | $ 10,358 | $ 6,161 |
| | | |
| LIABILITIES AND EQUITY | | |
| Current liabilities: | | |
| Trade and other payables (note 19) | $ 384 | $ 299 |
| Loans and borrowings (note 20) | 442 | 15 |
| Deferred revenue (note 21) | 60 | 25 |
| Provisions (note 22) | 25 | 25 |
| Other liabilities (note 23) | 50 | 26 |
| | 961 | 390 |
| Non-current liabilities: | | |
| Loans and borrowings (note 20) | 2,424 | 1,905 |
| Deferred revenue (note 21) | 3,221 | 1,016 |
| Deferred tax liabilities (note 16) | 39 | 46 |
| Provisions (note 22) | 91 | 86 |
| Other liabilities (note 23) | 96 | 46 |
| | 5,871 | 3,099 |
| Total liabilities | 6,832 | 3,489 |
| Equity attributable to the Owner of the Company: | | |
| Share capital (note 24) | 812 | 24 |
| Accumulated other comprehensive income (note 25) | 49 | 86 |
| Retained earnings | 2,665 | 2,562 |
| Total equity | 3,526 | 2,672 |
| TOTAL LIABILITIES AND EQUITY | $ 10,358 | $ 6,161 |

Approved on behalf of the Board,

Hugh J. Bolton
Director and Chairman of the Board

Vito Culmone
Director and Chairman of the Audit Committee



The accompanying notes are an integral part of these consolidated financial statements

# EPCOR UTILITIES INC.

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

December 31, 2017 and 2016

| | Share capital (note 24) | Accumulated other comprehensive income (loss): Available-for-sale financial assets (note 25) | Cumulative translation account (note 25) | Employee benefits account (note 25) | Retained earnings | Equity attributable to the Owner of the Company |
|---|---|---|---|---|---|---|
| Equity at December 31, 2015 | $ 24 | $ 1 | $ 105 | $ (9) | $ 2,394 | $ 2,515 |
| Net income for the year | - | - | - | - | 309 | 309 |
| Other comprehensive income (loss): | | | | | | |
| Re-measurements of net defined benefit plans | - | - | - | (1) | - | (1) |
| Fair value gain on available-for-sale investment in Capital Power | - | 43 | - | - | - | 43 |
| Fair value gain on available-for-sale investment in Capital Power reclassified to net income | - | (42) | - | - | - | (42) |
| Unrealized loss on foreign currency translation | - | - | (11) | - | - | (11) |
| Total comprehensive income (loss) | - | 1 | (11) | (1) | 309 | 298 |
| Dividends | - | - | - | - | (141) | (141) |
| Equity at December 31, 2016 | $ 24 | $ 2 | $ 94 | $ (10) | $ 2,562 | $ 2,672 |
| Net income for the year | - | - | - | - | 256 | 256 |
| Other comprehensive loss: | | | | | | |
| Re-measurements of net defined benefit plans | - | - | - | (5) | - | (5) |
| Fair value gain on available-for-sale investment in Capital Power reclassified to net income | - | (1) | - | - | - | (1) |
| Fair value loss on available-for-sale beneficial interest in sinking fund | - | (1) | - | - | - | (1) |
| Unrealized loss on foreign currency translation | - | - | (30) | - | - | (30) |
| Total comprehensive income (loss) | - | (2) | (30) | (5) | 256 | 219 |
| Capital contribution from the Owner | 788 | - | - | - | - | 788 |
| Dividends | - | - | - | - | (153) | (153) |
| Equity at December 31, 2017 | $ 812 | $ - | $ 64 | $ (15) | $ 2,665 | $ 3,526 |

The accompanying notes are an integral part of these consolidated financial statements

# EPCOR UTILITIES INC.

Consolidated Statements of Cash Flows
(In millions of Canadian dollars)

Years ended December 31, 2017 and 2016

| | 2017 | 2016 |
|---|---|---|
| Cash flows from (used in) operating activities: | | |
| Net income for the year | $ 256 | $ 309 |
| Reconciliation of net income for the year to cash from (used in) operating activities: | | |
| Interest paid | (116) | (128) |
| Finance expenses (note 8) | 115 | 112 |
| Income taxes recovered (paid) | (4) | 1 |
| Income tax expense (recovery) (note 9) | (14) | 9 |
| Depreciation and amortization (note 7) | 236 | 189 |
| Change in employee benefits provisions | 2 | (8) |
| Contributions received (note 21) | 48 | 21 |
| Deferred revenue recognized (note 21) | (38) | (37) |
| Fair value change on derivative instruments (note 13) | (1) | (2) |
| Fair value gain on available-for-sale investment in Capital Power reclassified from other comprehensive income (note 12) | (1) | (42) |
| Dividend income from available-for-sale investment in Capital Power | - | (9) |
| Other | (5) | (3) |
| Funds from operations | 478 | 412 |
| Change in non-cash operating working capital (note 26) | 48 | 63 |
| Net cash flows from operating activities | 526 | 475 |
| Cash flows from (used in) investing activities: | | |
| Acquisition or construction of property, plant and equipment and intangible assets[1] | (566) | (502) |
| Business acquisitions (note 5) | (68) | (51) |
| Proceeds on disposal of property, plant and equipment | 6 | 19 |
| Change in non-cash investing working capital (note 26) | 31 | 5 |
| Net payments received on other financial assets (note 15) | 14 | 314 |
| Payment of Drainage transition cost compensation to the City (note 23) | (8) | - |
| Net proceeds on sale of available-for-sale investment in Capital Power (note 12) | 6 | 204 |
| Distributions received from Capital Power | - | 12 |
| Net cash flows from (used in) investing activities | (585) | 1 |
| Cash flows from (used in) financing activities: | | |
| Net repayment of short-term loans and borrowings (note 27) | - | (98) |
| Proceeds from issuance of long-term loans and borrowings (note 27) | 400 | 52 |
| Repayment of long-term loans and borrowings (note 27) | (37) | (141) |
| Deferred debt issue costs (note 27) | (2) | - |
| Net contributions from (refunds to) customers and developers (note 27) | (2) | 7 |
| Dividends paid | (153) | (141) |
| Net cash flows from (used in) financing activities | 206 | (321) |
| Increase in cash and cash equivalents | 147 | 155 |
| Cash and cash equivalents, beginning of year | 191 | 36 |
| Cash and cash equivalents, end of year | $ 338 | $ 191 |

1 Interest payment of $6 million (2016 – $5 million) is included in acquisition or construction of property, plant and equipment and intangible assets.

The accompanying notes are an integral part of these consolidated financial statements

**1. Nature of operations**

EPCOR Utilities Inc. (the Company or EPCOR) builds, owns and operates electrical, natural gas and water transmission and distribution networks, water and wastewater treatment facilities and sanitary and stormwater systems. The Company also provides electricity, natural gas and water products and services to residential and commercial customers.

The Company operates in Canada and the United States (U.S.) with its registered head office located at 2000, 10423 - 101 Street NW, Edmonton, Alberta, Canada, T5H 0E8.

The common shares of EPCOR are owned by The City of Edmonton (the City). The Company was established by Edmonton City Council under City Bylaw 11071.

**2. Basis of presentation**

(a) Statement of compliance

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). These consolidated financial statements were approved and authorized for issue by the Board of Directors on February 15, 2018.

(b) Basis of measurement

The Company's consolidated financial statements are prepared on the historical cost basis, except for its beneficial interest in the sinking fund held with the City, available-for-sale investment in Capital Power, derivative financial instruments and contingent consideration which are measured at fair value.

**3. Significant accounting policies**

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements unless otherwise indicated.

(a) Basis of consolidation

These consolidated financial statements include the accounts of EPCOR and its wholly owned subsidiaries at December 31, 2017. Subsidiaries are entities controlled by the Company. The Company controls an entity when it is exposed to, or has rights to, variable returns from the performance of the entity and has the ability to affect those returns through its control over the entity. Subsidiaries are fully consolidated from the date on which EPCOR obtains control, and continue to be consolidated until the date that such control ceases to exist. All intercompany balances and transactions have been eliminated on consolidation. Unrealized gains arising from transactions with equity-accounted associates are eliminated against the investment to the extent of the Company’s interest in the investee. Unrealized losses are eliminated in the same way as unrealized gains, but only to the extent that there is no evidence of impairment. The financial statements of the subsidiaries are prepared for the same reporting period as EPCOR, using consistent accounting policies.

These consolidated financial statements are presented in Canadian dollars. The functional currency of EPCOR and its Canadian subsidiaries is the Canadian dollar; the functional currency of U.S. subsidiaries is the U.S. dollar. All the values in these consolidated financial statements have been rounded to nearest million except where otherwise stated.

(b) Changes in significant accounting policies

The Company adopted amendments to various accounting standards effective January 1, 2017 and the amendments did not have a significant impact on these consolidated financial statements.

(c) Business combinations and goodwill

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The determination of whether or not an acquisition meets the definition of business combination under IFRS requires judgment and is assessed on a case by case basis. The consideration for an acquisition is measured at the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. The consideration transferred does not include amounts related to the settlement of pre-existing relationships. Such amounts are recognized in net income. Transaction costs that the Company incurs in connection with a business combination, other than those associated with the issue of debt or equity securities, are expensed as incurred.

Identifiable assets acquired and liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Any contingent consideration payable is measured at fair value at the acquisition date. If the contingent consideration is classified as equity then it is not re-measured and settlement is accounted for within equity. Subsequent changes in the fair value of contingent consideration that is not classified as equity are recognized in net income.

Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Subsequently, goodwill is measured at cost less accumulated impairment losses, if any. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the carrying amount may be impaired. Impairment is determined by assessing the recoverable amount of the cash generating unit to which goodwill relates. Where the recoverable amount of the cash generating unit is less than the carrying amount, an impairment loss is recognized.

(d) Business combinations under common control

A 'business combination involving entities or businesses under common control' is a business combination in which all of the combining entities or businesses are ultimately controlled by the same party or parties both before and after the business combination, and that control is not transitory. Business combinations involving entities or businesses under common control are outside the scope of IFRS 3 - *Business Combinations* and currently there is no IFRS guidance on accounting for business combinations involving entities or businesses under common control. In accordance with IAS 8 - *Accounting Policies, Changes in Accounting Estimates and Errors*, if no applicable standard or interpretation exists then management must develop a policy that is reliable and relevant to the decision making needs of the users. As per the Company's business combinations under common control policy, common control transactions are accounted for using book value accounting; this requires the Company to recognize the transferred assets and liabilities at their respective carrying amounts. The difference between the fair value of consideration due and the net carrying amount of the assets and liabilities acquired is recorded as an adjustment to equity.

(e) Revenue recognition

Revenue is recognized to the extent that it is probable that economic benefits will flow to the Company for the provision of goods or services and where the revenue can be reliably measured. Revenues are measured at the fair value of the consideration received or to be received, excluding discounts, rebates and sales taxes or duty.

Certain water services contracts contain multiple-deliverables arrangements. Each deliverable that is considered to be a separate unit of account is accounted for individually. Significant judgment is required to determine an appropriate allocation of the total contract value to each unit of account based on the relative fair values of each unit. If the fair value of the delivered item is not reliably measurable, then revenue is allocated based on the difference between the total arrangement consideration and the fair value of the undelivered units of account. The primary identifiable deliverables under such contracts are for construction of plant and other infrastructure, project upgrades and expansions, financing or leasing of upgrades, and facilities operations and maintenance.

The Company's principal sources of revenue and recognition of these revenues for financial statement purposes are as follows:

*Sale of goods*

Revenues from sales of electricity, natural gas and water are recognized upon delivery. These revenues include an estimate of the value of electricity, natural gas and water consumed by customers and billed subsequent to the reporting period.

Revenues from the sale of other goods are recognized when the products have been delivered and collectability is probable.

*Provision of services*

Revenues from the provision of electricity and natural gas distribution and transmission services, sanitary and stormwater collection and wastewater treatment services are recognized over the period in which the service is performed and collectability is probable. Revenues from the provision of other services are recognized when the services have been rendered and collectability is probable.

*Construction contracts*

Contract revenue from the construction of water and wastewater treatment plants and other project upgrades and expansions provided to customers is recognized in profit or loss on the percentage of completion basis when the projected final cost of a construction contract can be reliably estimated. Contract revenue includes the initial amount agreed in the contract plus any variations in contract work, claims and incentive payments, to the extent that it is probable that they will result in revenue and can be reliably measured. Percentage of completion is estimated based on an assessment of progress towards the completion of contract tasks. These estimates may result in the recognition of unbilled receivables when the revenues are earned prior to billing customers. If progress billings exceed costs incurred plus recognized profits, then the difference is presented as deferred revenue in the statement of financial position. Contract expenses are recognized as incurred unless they create an asset related to future contract activity.

When the outcome of a construction contract cannot be estimated reliably, contract revenue is recognized only to the extent of contract costs incurred that are probable to be recoverable.

Provisions for estimated losses on uncompleted contracts are made for the full amount of the projected loss in the period in which the losses are identified. Revenues and costs related to variations are included in the total estimated contract revenue and expenses when it is probable that the customer will approve the variation and the amount of revenue arising from the variation can be reliably measured.

*Revenues earned under finance leases*

Finance income earned from arrangements where the Company leases water and wastewater assets to customers are accounted for as finance leases, as described in note 3(i).

*Interest income*

Revenue from the financing of project upgrades and expansions is recognized over the term of each contract using the effective interest method based on the fair value of the loan calculated at inception for each contract.

Interest income related to the loans receivable from Capital Power is recognized over the terms of the loans based on the interest rate applicable to each loan.

Interest income relating to short-term investments and cash deposits is recognized on time proportion basis taking into account the applicable interest rates.

(f) Income taxes

Under the Income Tax Act (Canada) (ITA), a municipally owned corporation is subject to income tax on its taxable income if the income from activities for any relevant period that was earned outside the geographical boundaries of the municipality exceeds 10% of the corporation's total income for that period. As a result of these and other provisions, certain Canadian subsidiaries of the Company are taxable under the ITA and provincial income tax acts. The U.S. subsidiaries are subject to income taxes pursuant to U.S. federal and state income tax laws.

Current income taxes for the current or prior periods are measured at the amount expected to be recovered from or payable to the taxation authorities based on the tax rates that are enacted or substantively enacted by the end of the reporting period.

Deferred tax assets and liabilities are recognized for the deferred tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the date of enactment or substantive enactment. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries except where the Company is able to control the timing of the reversal of the temporary differences, and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with investments in subsidiaries are only recognized to the extent that the temporary difference will reverse in the foreseeable future and the Company judges that it is probable that there will be sufficient taxable income against which to utilize the benefits of the temporary differences. Deferred tax assets and liabilities are not recognized if the temporary difference arises from the initial recognition of goodwill arising from a business combination or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither taxable income nor accounting income.

Current and deferred taxes are recognized in profit or loss except to the extent that they relate to items recognized directly in equity or in other comprehensive income.

(g) Cash and cash equivalents

Cash and cash equivalents include cash and short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

(h) Inventories

Small parts and other consumables, the majority of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. 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. Previous write downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances. The Company estimates the value of inventory that is expected to be used in the construction of property, plant and equipment (PP&E) and reports this value as construction work in progress under PP&E.

(i) Lease arrangements

At the inception of an arrangement entered into for the use of an asset, the Company determines whether such an arrangement is, or contains, a lease. A specific asset is the subject of a lease if fulfillment of the arrangement is dependent on the use of the specific asset and the arrangement conveys a right to use the asset. An arrangement conveys the right to use the asset if the right to control the use of the underlying asset is transferred. Where it is determined that the arrangement contains a lease, the Company classifies the lease as either a finance or operating lease dependent on whether substantially all the risks or rewards of ownership of the asset have been transferred.

Where the Company is the lessor, finance income related to leases or arrangements accounted for as finance leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment in the lease is the aggregate of net minimum lease payments and unearned finance income discounted at the interest rate implicit in the lease. Unearned finance income is deferred and recognized in net income over the lease term.

Where the Company is the lessee, leases or other arrangements that transfer substantially all of the benefits and risks of ownership of property to the Company are classified as finance leases. All other arrangements that are determined to contain a lease are classified as operating leases. Rental payments under arrangements classified as operating leases are expensed on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(j) Property, plant and equipment

PP&E are recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any.

Cost includes contracted services, materials, direct labor, directly attributable overhead costs, borrowing costs on qualifying assets and decommissioning costs. Where parts of an item of PP&E have different estimated economic useful lives, they are accounted for as separate items (major components) of PP&E.

The cost of major inspections and maintenance is recognized in the carrying amount of the item if the asset recognition criteria are satisfied. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing are expensed as incurred.

Depreciation of cost less residual value is charged on a straight-line basis over the estimated economic useful lives of items of each depreciable component of PP&E, from the date they are available for use, as this most closely reflects the expected usage of the assets. Land and construction work in progress are not depreciated. Estimating the appropriate economic useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of similar assets. The estimated economic useful lives, methods of depreciation and residual values are reviewed annually with any changes adopted on a prospective basis.

The ranges of estimated economic useful lives for PP&E assets used are as follows:

| | |
|---|---|
| Water treatment and distribution, and wastewater collection and treatment | 3 – 95 years |
| Energy transmission and distribution | 3 – 65 years |
| Retail systems and equipment | 4 – 10 years |
| Corporate information systems and equipment | 2 – 15 years |
| Leasehold improvements | 5 – 25 years |

Gains and losses on the disposal of PP&E are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(k) Capitalized borrowing costs

The Company capitalizes interest during construction of a qualifying asset using the weighted average cost of debt incurred on the Company's external borrowings or specific borrowings used to finance qualifying assets. Qualifying assets are considered to be those that take a substantial period of time to construct.

(l) Intangible assets

Intangible assets with finite lives are stated at cost, net of accumulated amortization and impairment losses, if any. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination that meet the specified criteria for recognition apart from goodwill, is allocated to the individual assets acquired based on their relative fair value.

Customer rights represent the costs to acquire the rights to provide electricity services to particular customer groups for a finite period of time. Other rights represent the costs to acquire the rights, for finite periods of time, to access electricity delivery corridors, to the supply of water, to provide sewage treatment and transportation services, to withdraw groundwater and to the supply of potable water for emergency and peak purposes. Customer and other rights are recorded at cost at the date of acquisition. A subsequent expenditure is capitalized only when it increases the future economic benefit in the specific asset to which it relates.

The cost of intangible software includes the cost of license acquisitions, contracted services, materials, direct labor, along with directly attributable overhead costs and borrowing costs on qualifying assets.

Amortization of the cost of finite life intangible assets is recognized on a straight-line basis over the estimated economic useful lives of the assets, from the date they are available for use, as this most closely reflects the expected usage of the asset. Work in progress is not amortized. The estimated economic useful lives and methods of amortization are reviewed annually with any changes adopted on a prospective basis.

The estimated economic useful lives for intangible assets with finite lives are as follows:

| | |
|---|---|
| Customer rights | 20 years |
| Software | 2 – 20 years |
| Other rights | 12 – 50 years |
| Water rights | 100 years |

Certificates of convenience and necessity (CCN) represent the costs to acquire the exclusive rights for the Company to serve within its specified geographic areas in the U.S. for an indefinite period of time. CCN are not amortized but are subject to review for impairment at the end of each reporting period.

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(m) Service concession arrangements

Service concession arrangements are contracts between the Company and government entities and can involve the design, build, finance, operation and maintenance of public infrastructure in which the government entity controls (i) the services provided by the Company and (ii) significant residual interest in the infrastructure. Service concession arrangements are classified in one of the following categories:

(i) financial asset
The Company recognizes a financial asset arising from service concession arrangement when it has an unconditional right to receive a specified amount of cash or other financial asset over the life of the arrangement. The financial asset is measured at the fair value of consideration received or receivable. When the Company delivers more than one category of activities in a service concession arrangement, the consideration received or receivable is allocated by reference to the relative fair value of the activity, when amounts are separately identifiable.

(ii) intangible asset
The Company recognizes an intangible asset arising from service concession arrangement when it has a right to charge for usage of the public infrastructure. The intangible asset, recognized as consideration for providing construction or upgrade services under a service concession arrangement, is measured at fair value upon initial recognition. Subsequent to initial recognition, the intangible asset is measured at cost less accumulated amortization and impairment losses, if any.

Revenue under the service concession arrangements is recognized as per the revenue recognition policy of the Company described in note 3(e) by reference to each activity when the amount of revenue is separately identifiable.

The accounting for investment in contracts with government entities requires the application of judgment in determining if they fall within the scope of IFRIC 12 – Service Concession Arrangements (IFRIC 12). Additional judgment also needs to be exercised when determining, among other things, the classification to be applied to the service concession asset (i.e. financial asset or intangible asset), allocation of consideration between revenue generating activities, classification of cost incurred on such concessions and the effective interest rate to be applied to the service concession asset. Contracts falling under IFRIC 12 require use of estimates over the term of the arrangement, and therefore any change in the long term estimates could result in significant variation in the amounts recognized under service concession arrangements.

(n) Deferred revenue

Certain assets may be acquired or constructed using non-repayable government grants or contributions from developers or customers. Non-refundable contributions received towards construction or acquisition of an item of PP&E which are used to provide ongoing service to a customer are recorded as deferred revenue and are amortized on a straight line basis over the estimated economic useful lives of the assets to which they relate.

(o) 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. The increase in the provision due to the passage of time is recognized as a financing expense over the estimated time period until settlement of the obligation. Significant judgment is required to determine whether a past event results in a liability that is recognized in the statement of financial position. In addition, quantifying such provision also involves a certain amount of estimation in respect of the amount and timing of outflows of economic benefits and therefore it is possible that the assumptions used in measuring the provision may differ from future outcomes and the impact of such variations could be material.

The Company recognizes a decommissioning provision in the period in which a legal or constructive obligation is incurred. A corresponding asset for the decommissioning cost is added to the carrying amount of the associated PP&E, and is depreciated over the estimated useful life of the asset.

The Company may receive contributions from customers, homebuilders, real estate developers, and others to fund construction necessary to extend service to new areas. Certain of these contributions may be refunded over a limited period of time as new customers begin to receive service or other contractual obligations are fulfilled. The portion of contributions which are estimated to be refunded in the future are recorded as provisions. The remaining contributions are classified as deferred revenue.

(p) Employee benefits

The employees of the Company are either members of the Local Authorities Pension Plan (LAPP) or other defined benefit or defined contribution pension plans.

The LAPP is a multi-employer defined benefit pension plan. The trustee of the plan is the Alberta President of Treasury Board and Minister of Finance and the plan is administered by a Board of Trustees. The Company and its employees make contributions to the plan at rates prescribed by the Board of Trustees to cover costs and an unfunded liability under the plan. The rates are based on a percentage of the pensionable salary. The most recent actuarial report of the plan discloses an unfunded liability. It is accounted for as a defined contribution plan as the LAPP is not able to provide information which reflects EPCOR's specific share of the defined benefit obligation or plan assets that would enable the Company to account for the plan as a defined benefit plan. Accordingly, the Company does not recognize its share of any plan surplus or deficit.

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to certain management employees and employees who are not otherwise served by the LAPP, including employees of new or acquired operations. Employees not otherwise served by LAPP comprise less than 14% of total employees (2016 – 17%).

Short-term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided. A liability for short-term employee benefits is recognized for the amount expected to be paid if the Company has a legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

The Company recognizes the contribution payable to a defined contribution plan as an expense and a liability in the period during which the service is rendered.

(q) Derivative financial instruments

The Company uses various risk management techniques to reduce its exposure to movements in electricity prices, interest rates and foreign currency exchange rates. These include the use of derivative financial instruments such as forward contracts or contracts-for-differences and interest rate swaps. Such instruments may be used to establish a fixed price for electricity, fixed interest rates for borrowings or fixed foreign currency rates for anticipated transactions denominated in a foreign currency. Embedded derivatives are separated from the host contract and accounted for as a derivative if certain criteria are met.

The Company sells electricity to customers under a Regulated Rate Tariff (RRT). As part of the RRT, the amount of electricity to be economically hedged, the hedging method and the electricity selling prices to be charged to these customers is determined by a regulatory approved Energy Price Setting Plan (EPSP). Under the EPSP, the Company manages its exposure to fluctuating wholesale electricity spot prices and consumption volume by entering into financial electricity purchase contracts in advance of the month of consumption in order to economically hedge the price of electricity under a well-defined risk management process set out in the EPSP. Under these instruments, the Company agrees to exchange, with a single creditworthy and adequately secured counterparty, the difference between the Alberta Electric System Operator (AESO) market price and the fixed contract price for a specified volume of electricity for the forward months, all in accordance with the EPSP. The Company may enter into additional financial electricity purchase contracts outside the EPSP to further economically hedge the price of electricity.

Interest rates swaps are used by the Company to manage interest rate risks associated with long-term loans and borrowings and result in securing fixed interest rates over the term of the loans and borrowings against the floating interest rate.

Foreign exchange forward contracts may be used by the Company to manage foreign exchange exposures, consisting mainly of U.S. dollar exposures, resulting from anticipated transactions denominated in foreign currencies.

All derivative financial instruments are recorded at fair value as derivative assets or derivative liabilities on the statement of financial position, to the extent they have not been settled, with all changes in the fair value of derivatives recorded in net income. At initial recognition, transaction costs attributable to the derivative financial instruments are recognized in net income.

The fair value of derivative financial instruments reflects changes in the electricity prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price, as appropriate, in active markets. Fair value amounts reflect management's best estimates using external readily observable market data, such as forward prices, interest rates, foreign exchange rates and discount rates for time value. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(r) Non-derivative financial instruments

Financial assets are identified and classified as one of the following: measured at fair value through profit or loss, loans and receivables, or available-for-sale financial assets. Financial assets are measured at fair value through profit or loss if classified as held for trading or designated as such upon initial recognition. Financial liabilities are classified as measured at fair value through profit or loss or as other financial liabilities.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

*Financial instruments at fair value through profit or loss*

The Company may designate financial instruments as measured at fair value through profit or loss when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis.

Upon initial recognition, directly attributable transaction costs are recognized in net income as incurred. Changes in fair value of financial instruments measured at fair value through profit or loss are recognized in net income.

*Loans and receivables*

Cash and cash equivalents, trade and other receivables, and other financial assets are classified as loans and receivables.

The Company's loans and receivables are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost using the effective interest method less any impairment as described in note 3(s). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the finance income or expense over the term of the financial asset or liability using an effective interest rate. The effective interest rate is the rate that exactly discounts estimated future cash payments or receipts through the expected life of the financial instrument, or a shorter period when appropriate, to the net carrying amount of the financial asset or financial liability.

*Available-for-sale financial assets*

Available-for-sale financial assets are non-derivative financial assets that are designated as available-for-sale and that are not classified in other categories. These assets are initially recognized at fair value plus directly attributable transaction costs. Subsequent to initial recognition, they are measured at fair value with unrealized gains and losses, other than impairment losses, recognized in other comprehensive income and presented within equity in the fair value reserve. On derecognition of an available-for-sale financial asset, the cumulative gain or loss that was previously held in equity is transferred to net income.

The Company's beneficial interest in the sinking fund with the City and available-for-sale investment in Capital Power do not meet the criteria for classification in any of the previous categories and are classified as available-for-sale financial assets and measured at fair value with changes in fair value reported in other comprehensive income until they are disposed of or becomes impaired, as described in note 3(s).

*Other financial liabilities*

The Company’s trade and other payables, debentures and borrowings, contributions from customers and developers and other liabilities are classified as other financial liabilities and recognized on the date at which the Company becomes a party to the contractual arrangement. Other financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire.

Other financial liabilities are initially recognized at fair value including debenture discounts and premiums, plus directly attributable transaction costs, such as issue expenses, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

(s) Impairment of financial assets

The Company's financial assets held as loans and receivables or available-for-sale assets are assessed for indicators of impairment at each reporting date. An impairment loss for financial assets is recorded when it is identified that there is objective evidence that one or more events has occurred, after the initial recognition of the asset, that has had a negative impact on the estimated future cash flows of the asset and that can be reliably estimated. The objective evidence for these types of assets is as follows:

(i) For listed and unlisted investments in equity securities classified as available-for-sale, a significant or prolonged decline in the fair value of the investment below its cost is considered to be objective evidence of impairment. Impairment losses recognized are not reversed in subsequent periods.

(ii) For all other financial assets, including finance lease receivables, objective evidence of impairment includes significant financial difficulty of the counterparty or default or delinquency in interest or principal payments.

(iii) Trade receivables and other assets that are not assessed for impairment individually are assessed for impairment on a collective basis. Objective evidence of impairment includes the Company's past experience of collecting payments as well as observable changes in national or local economic conditions.

For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the asset's original effective interest rate. If, in a subsequent period, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed or adjusted within net income. An impairment loss is reversed only to the extent that the financial asset's carrying amount does not exceed the carrying amount that would have been determined, if no impairment loss had been recognized.

(t) Impairment of non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E, intangible assets and goodwill. For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated at least once each year.

The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the cash-generating unit, or CGU). For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation is subject to an operating segment ceiling test and reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

The Company's corporate assets do not generate separate cash inflows. If there is an indication that a corporate asset may be impaired, then the recoverable amount is determined for the CGU to which the corporate asset belongs.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units, and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other non-financial assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(u) Foreign currency transactions and translation

*Foreign currency transactions*

Transactions denominated in currencies other than the Canadian dollar are translated at exchange rates in effect at the transaction date. At each reporting date, monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the end of the reporting period. Other non-monetary assets and liabilities are not retranslated unless they are carried at fair value. The resulting foreign exchange gains and losses are included in net income.

*Foreign operations translation*

On consolidation, the assets and liabilities of foreign operations that have a functional currency other than Canadian dollars are translated into Canadian dollars at the exchange rates in effect at the end of the reporting period. Revenues and expenses are translated at the average monthly exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in the cumulative translation account in accumulated other comprehensive income.

(v) Segment reporting

An operating segment is a component of the Company that engages in business activities from which it may earn revenues and incur expenses, including revenues and expenses that relate to transactions with any of the Company's other components. Transactions between segments are made under terms that approximate market value. The accounting policies of the segments are the same as those described in note 3 and other relevant notes and are measured in a manner consistent with that of the consolidated financial statements. The results for all operating segments, for which discrete financial information is available, are reviewed regularly by the Company's management to assess its performance and make decisions about resources to be allocated to the segment.

Segment results that are reported to management include items directly attributable to the segment as well as those that can be allocated on a reasonable and consistent basis. Unallocated items comprise mainly corporate assets, head office expenses and income tax assets and liabilities.

Segment capital expenditure is the total cost incurred during the period to acquire or construct PP&E and intangible assets other than goodwill.

During the year, the Company reassessed its business segments due to the addition of Drainage Utility Services (Drainage). Drainage has been aggregated with the existing Canadian water operations under the Water Services segment while U.S. operations are now being reported as a separate business segment. As a result of reassessment, the comparative information presented in these consolidated financial statements has also been revised to correspond with the new business segments.

The Company uses significant judgment in identification and aggregation of business segments. The Company aggregates business segments when they offer similar products and services, have similar business processes, use similar methods to distribute the goods and services, have similar customer bases and operate under similar regulatory environments.

(w) Standards and interpretations not yet applied

A number of new standards, amendments to standards and interpretations have been issued by the IASB and the International Financial Reporting Interpretations Committee the application of which is effective for periods beginning on or after January 1, 2018. Those which may be relevant to the Company and may impact the accounting policies of the Company are set out below. The Company does not plan to adopt these standards early.

IFRS 9 - *Financial Instruments* (IFRS 9), which replaces IAS 39 - *Financial Instruments: Recognition and Measurement*, includes a new classification and measurement approach for financial assets that reflects the business model in which they are held and the characteristics of their contractual cash flows. IFRS 9 contains three principal classification categories for financial assets including (i) measured at amortized cost, (ii) fair value through other comprehensive income and (iii) fair value through profit or loss. IFRS 9 also replaces the "incurred loss" model under IAS 39 with a forward looking "expected credit loss" (ECL) model for recognition of impairment on financial instruments. The effective date for implementation of IFRS 9 has been set for annual periods beginning on or after January 1, 2018.

Based on the assessment of the Company's existing financial instruments, the Company does not expect any material impact on the accounting for its financial instruments as a result of the adoption of IFRS 9. The Company expects to record an adjustment to the provision of allowance of doubtful accounts on its trade receivables resulting from the application of the methodology of the calculation prescribed by the new standard. As per the Company's existing policy, the allowance for doubtful accounts is calculated on the overdue balances of trade receivables only, whereas the new impairment model requires the Company to calculate the lifetime ECL on the initial recognition of trade receivables, instead of on the overdue balances only. Accordingly, the Company will be required to recognize the lifetime ECL on all outstanding trade receivables. As the Company has very short credit periods for trade receivables, the Company does not expect any material impact due to implementation of the new requirements in IFRS 9.

The Company will also change the classification of its beneficial interest in the sinking fund with the City, which is currently classified as available-for-sale investment. Since the available-for-sale classification is no longer available under IFRS 9 the Company will re-designate its beneficial interest in sinking fund at fair value through profit or loss. This change is not expected to have a material impact.

IFRS 15 - *Revenue from Contracts with Customers* (IFRS 15), which replaces IAS 11 - *Construction Contracts* and IAS 18 - *Revenue* and related interpretations, is effective for annual periods commencing on or after January 1, 2018. IFRS 15 introduces a new single revenue recognition model for contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized.

There are two methods by which the new standard can be adopted: (1) a full retrospective approach with a restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment recognized in retained earnings as of the date of adoption. The Company will adopt IFRS 15 using the modified retrospective approach with the cumulative effect of the adjustment, if any, recognized as of January 1, 2018, subject to allowable and elected practical expedients.

The Company has performed detailed analysis on each revenue stream that is within the scope of the new standard through review of the underlying contracts with customers to determine the impact of IFRS 15 on the consolidated financial statements. A significant portion of the Company’s revenue is generated from providing utility goods and services. The Company will continue to recognize utility revenue over time as the Company’s customers simultaneously receive and consume the utility goods and services as they are provided.

The Company is finalizing its review and quantification of IFRS 15 application to contributions from customers and developers. Contributions, which may be in the form of physical assets or financial contributions, help fund infrastructure that will be used by the utility to provide ongoing services to customers. Such contributions are currently recorded as deferred revenue when received and are amortized and recognized as revenue on a straight-line basis over the estimated economic useful lives of the assets to which they relate. The Company is finalizing its review of all contributions recognized as deferred revenue to identify the contributions which will fall under the scope of IFRS 15, which includes the quantification of the impact of any change in the accounting treatment to contributions that fall within the scope of the new standard. Preliminary analysis suggests that contributions received where the utility will have an ongoing performance obligation with the contributor will fall under the scope of IFRS 15, with the fair value of contributed assets to be recognized as revenue over the period which related services will be provided. However, contributions where the utility has no ongoing performance obligation with the contributor will likely fall outside the scope of IFRS 15, and as a result, the Company is assessing whether a change in accounting treatment is required for these contributions.

The Company is also finalizing its review and quantification of the impact of IFRS 15 on the recognition and presentation of energy sales and energy purchases and system access fees. Any potential adjustments would relate only to the classification of these amounts under IFRS 15 and would not have a material impact on the adjustment recorded under the modified retrospective approach.

For the Energy Services segment, the Company currently recognizes gross revenue from sales of energy, which include collection of third party distribution and transmission charges. All related distribution and transmission costs are recognized as operating expenses under energy purchases and system access fees. The Company is finalizing its position regarding whether the third party distribution and transmission charges to customers will constitute consideration received for fulfillment of a performance obligation or are a flow-through charge.

In the Distribution and Transmission segment, the Company currently recognizes gross revenues which include collection of provincial transmission system access service charges. All provincial transmission system access service costs are recognized as operating expenses under energy purchases and system access fees. The Company is finalizing its position as to whether the provincial transmission system access service costs charged to customers will constitute consideration received for fulfillment of a performance obligation or are a flow-through charge.

For all other contracts with customers, the Company does not expect the implementation of IFRS 15 to have material changes in the timing or amounts of revenues recognized.

As a result of the adoption of the new standard, the Company will be required to include significant disclosures in the financial statements based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating how and when revenues are recognized and information related to contract assets and deferred revenues. In addition, IFRS 15 requires that the Company's revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing, and estimates of revenues and cash flows generated from contracts with customers. The Company is in the process of preparing its draft disclosures, which will be required in the first quarter of 2018.

IFRS 16 - *Leases* (IFRS 16), which replaces IAS 17 – *Leases* (IAS 17), is effective for annual periods commencing on or after January 1, 2019. IFRS 16 combines the existing dual model of operating and finance leases under IAS 17 into a single lessee model. Under the new single lessee model, a lessee will recognize lease assets and lease liabilities on the statement of financial position initially measured at the present value of unavoidable lease payments. IFRS 16 will also cause expenses to be higher at the beginning and lower towards the end of a lease, even when payments are consistent throughout the term. Leases for duration of twelve months or less and leases of low value assets are exempted from recognition on the statement of financial position. Lessors will continue with a dual lease classification model and the classification will determine how and when a lessor will recognize lease revenue and what assets will be recorded.

The Company is currently reviewing the contracts that are identified as leases, or that could be classified as leases under IFRS 16, in order to evaluate the impact of adoption of IFRS 16 on the consolidated financial statements. Based on preliminary assessment, the Company expects that there will be a material impact on its statements of consolidated financial position requiring the recognition of lease assets and lease obligations with respect to its leases for office space, which are currently classified as operating leases.

IFRIC 23 – *Uncertainty over Income Tax Treatments* is effective for annual periods commencing on or after January 1, 2019. The interpretation provides guidance on the recognition and measurement of current and deferred tax assets and liabilities under IAS 12 – *Income Taxes* when there is uncertainty over income tax treatments. The Company does not expect a material impact on initial application of the interpretation however, the interpretation may impact the Company's recognition, measurement and disclosure of uncertain tax treatments in the future.

## 4. Use of judgments and estimates

The preparation of the Company's consolidated financial statements in accordance with IFRS requires management to make judgments in the application of accounting policies, and estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the consolidated financial statements.

(a) Judgments

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements are included in notes:

Note 3(c) – Business acquisitions
Note 3(d) – Business combinations under common control
Note 3(e) – Revenue recognition
Note 3(m) – Service concession arrangements
Note 3(o) – Provisions
Note 3(v) – Segment reporting

(b) Estimates

The Company reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates.

Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

**Revenues**

By regulation, electricity wire service providers in Alberta have four months to submit the final electricity load settlement data after the month in which such electricity was consumed. The data and associated processes and systems used by the Company to estimate electricity revenues and costs, including unbilled consumption, are complex. The Company's estimation procedures will not necessarily detect errors in underlying data provided by industry participants including wire service providers and load settlement agents.

**Fair value measurement**

For accounting measures such as determining asset impairments, purchase price allocations for business combinations, recording financial assets and liabilities, and the recording and disclosure of certain non-financial assets, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value may be based on readily determinable market values or on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. Financial instruments, other than those classified as loans and receivables and other financial liabilities, are recorded at fair value which may require the use of estimated future prices.

**Deferred taxes**

Significant estimation and judgment is required in determining the provision for income taxes. Recognition of deferred tax assets in respect of deductible temporary differences and unused tax losses and credits is based on management's estimation of future taxable profit against which the deductible temporary differences and unused tax losses and credits can be utilized. The actual utilization of these deductible temporary differences and unused tax losses and credits may vary materially from the amounts estimated.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 5. Business transfer and acquisitions

Transfer of Drainage Utility Services from the City of Edmonton

The City transferred its Drainage business to EPCOR on September 1, 2017 pursuant to an Asset and Liability Transfer Agreement. The Drainage business is comprised of the sanitary drainage utility and the stormwater drainage utility which provide sanitary and stormwater collection and conveyance, as well as bio solids management and disposal.

The transfer of Drainage was a business combination involving a business under common control as it did not result in a change in the ultimate control of the Drainage business. Consistent with the Company's policy for business combinations under common control, book value accounting has been applied to the transaction and therefore all assets and liabilities have been initially recognized at their carrying amounts as recorded by the City, on the date of transfer, adjusted to align with IFRS. As of September 1, the adjusted carrying amounts of the transferred assets and liabilities are summarized as follows:

| | | |
|---|---|---|
| Book value of net assets transferred: | | |
| Trade and other receivables | $ | 90 |
| Inventories | | 1 |
| Property, plant and equipment | | 3,566 |
| Intangible assets | | 1 |
| Total assets | | 3,658 |
| Trade and other payables | | (39) |
| Deferred revenue | | (2,152) |
| Other liabilities | | (3) |
| Total liabilities | | (2,194) |
| Net assets | $ | 1,464 |

| | | |
|---|---|---|
| Consideration: | | |
| Promissory note | $ | 604 |
| Transition cost compensation | | 72 |
| Total consideration | $ | 676 |

The difference of $788 million between the adjusted carrying amount of the net assets transferred of $1,464 million less the fair value of consideration due of $676 million was recognized in equity as a capital contribution received from the City.

The trade and other receivables included trade receivables of $14 million due from customers and $10 million from related parties of Drainage. Trade and other receivables also include a balance of $66 million due from the City, being the Drainage utility's cash on hand on the date of transfer.

Property, plant and equipment primarily consist of sanitary and stormwater collection and treatment facilities. Property, plant and equipment include construction work in progress of $108 million and land of $238 million.

Trade and other payables include trade payables, accrued liabilities, accrued interest and amounts due to employees.

Deferred revenue represents cash contributions and contributed assets received from customers and developers as well as grants received from government authorities. Deferred revenue will be recognized as revenue over the corresponding life of the respective assets to which the contributions or grants relate.

Other liabilities primarily consist of deposits from customers and contractors.

The promissory note of $604 million represents the fair value of an obligation to the City which mirrors the principal and interest payment obligations of debentures issued by the City in respect of the Drainage business. This long-term debt bears interest at a weighted average rate of approximately 3.41% and will be fully settled by June, 2042. During the term of the obligation, blended payments of principal and interest are due at various times throughout each year.

As per the terms of the Asset and Liability Transfer, the Company will pay transition cost compensation of $75 million to the City over time to compensate the City for stranded costs, including liabilities retained by the City, related to the transfer. On the date of the transfer, the Company paid $8 million to the City and recognized the present value of the remaining transition cost compensation liability of $64 million within other liabilities on the consolidated statements of financial position.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

On the transfer of Drainage, the Company has also assumed commitments for capital and construction projects of $119 million which are expected to be complete by the end of 2020.

Since the date of transfer to December 31, 2017, the financial performance of Drainage services is as follows:

| | | 2017 |
|---|---|---|
| Revenue and other income | $ | 75 |
| Operating expenses | | (62) |
| Operating income | | 13 |
| Financing expenses | | (7) |
| Net income for the period | $ | 6 |

The financial results and assets and liabilities of Drainage have been incorporated in these consolidated financial statements from the date of transfer of Drainage to the Company. Accordingly, the comparative information does not include any financial information relating to Drainage prior to the transfer date.

Hughes Gas Resources, Inc.

On June 1, 2017 the Company acquired 100% of the common shares of Hughes Gas Resources, Inc. (Hughes), a natural gas distribution, transmission and services holding company with four wholly owned subsidiaries operating northwest of Houston, Texas, for total consideration of $54 million (US$40 million) and the assumption of $14 million (US$10 million) in third party debt.

Hughes is primarily involved in the distribution of natural gas to approximately 4,300 customer connections through its rate regulated subsidiary Hughes Natural Gas, Inc. which owns and operates a 354 kilometer natural gas distribution network. Other subsidiaries include Alamo Pipeline, LLC, the owner and operator of a rate regulated natural gas transmission pipeline which transports natural gas from suppliers to Hughes Natural Gas, Inc. through its 51 kilometer pipeline. These operations are regulated by the Railroad Commission of Texas. The acquisition also includes two unregulated subsidiaries, Pinehurst Utility Construction, LLC (infrastructure contractor) and Goliad Midstream Energy, LLC (intermediary company for negotiation of natural gas supply contracts).

The purchase price was allocated to the assets acquired and liabilities assumed based on their fair values on the date of acquisition, in Canadian dollars as follows:

| | | |
|---|---|---|
| Fair value of net assets acquired: | | |
| Trade and other receivables | $ | 2 |
| Property, plant and equipment | | 66 |
| Intangible assets | | 1 |
| Trade and other payables | | (1) |
| Loans and borrowings | | (14) |
| Net assets acquired at fair value | $ | 54 |

| | | |
|---|---|---|
| Consideration: | | |
| Cash | $ | 46 |
| Contingent consideration | | 8 |
| Total consideration | $ | 54 |

The intangible assets of $1 million represent the fair value of a franchise agreement with the City of Magnolia for the distribution of natural gas.

Loans and borrowings of $14 million represent the fair value of existing third party debt assumed by the Company as part of the transaction. Subsequent to the acquisition date, the Company repaid all of the assumed third party debt.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

Contingent consideration with a fair value of $8 million was recognized at the date of acquisition. The contingent consideration consists of the Company's commitment to pay a fee, with a cap of US$8 million, to the previous owners of Hughes on the addition of new customer connections above a minimum of 600 incremental customer connections over a period of up to six years from the date of closing.

The transaction has been accounted for using the acquisition method in conformance with IFRS 3 – *Business Combinations* with the results of operations included in the consolidated financial statements from the date of acquisition. Total revenue and net income included in the consolidated statements of comprehensive income since the date of acquisition to December 31, 2017 was $6 million and nil, respectively. The consolidated statements of comprehensive income up to December 31, 2017 would have included estimated revenue and net income of $9 million and $1 million, respectively, had the acquisition of assets occurred on January 1, 2017.

Management used assumptions and estimates about future events in the determination of fair values. The assumptions and estimates with respect to the determination of the fair value of property, plant and equipment, intangible assets and contingent consideration required the most judgment. The key assumptions in determination of fair value included future regulatory rates, discount rate, future growth rates and expected additional customer connections for supply of natural gas. Based on those assumptions and estimates, the purchase price was allocated to the identified assets and liabilities, including contingent consideration. The fair values were estimated by applying standard valuation techniques. For property, plant and equipment, a replacement cost estimate was prepared by an external consultant and the fair value was then determined internally by making adjustments for functional and economic obsolescence. The fair value of contingent consideration was based on management's expectations for the addition of new customer connections over the period of six years from the date of acquisition, discounted to present value.

Natural Resources Gas Limited:

On November 1, 2017, the Company assumed operations and acquired substantially all of the natural gas distribution assets of Natural Resource Gas Limited for cash consideration of $22 million and now distributes and sells natural gas to over 8,700 residential, commercial and industrial customers in the counties of Elgin, Middlesex, Oxford and Norfolk in southwestern Ontario. The distribution system consists of approximately 640 kilometers of distribution mains. The operations are regulated by the Ontario Energy Board under a price cap incentive cost-of-service rate setting framework.

Blue Water 130 Pipeline

On August 19, 2016, the Company completed the acquisition of the assets of Blue Water Project 130 L.P. (Blue Water) and Cross County Water Supply Corporation (CCWSC) through its wholly owned U.S. subsidiaries EPCOR 130 Project Inc. and 130 Regional Water Supply Corporation respectively for total consideration of $82 million (US$64 million).

The assets acquired from Blue Water and CCWSC include an 85 kilometer water supply pipeline, near Austin, Texas, U.S., with designed capacity of nearly 18 million gallons per day along with groundwater well production systems and long term wholesale water supply agreements.

The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values on the date of acquisition, in Canadian dollars as follows:

| | | |
|---|---|---|
| Fair value of net assets acquired: | | |
| Intangible assets | $ | 13 |
| Goodwill | | 2 |
| Property, plant and equipment | | 68 |
| Deferred revenue | | (1) |
| Net assets acquired at fair value | $ | 82 |
| Consideration: | | |
| Cash | $ | 48 |
| Contingent consideration | | 34 |
| Total consideration | $ | 82 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

The intangible assets of $13 million consist of the right to receive groundwater up to the maximum capacity of the pipeline for a period of at least 99 years.

The goodwill recognized at fair value of $2 million includes the value of the expected benefits to the Company by providing a commercial platform to develop other similar projects and future cost synergies which may result from the Company's expanded operations in the State of Texas, U.S. The goodwill is deductible for income tax purposes over time.

Contingent consideration with a fair value of $34 million was recognized at the date of acquisition. The contingent consideration consists of the Company's commitment to pay Blue Water (i) a fee of up to US$32 million based on securing newly executed long term contracts for the supply of water and (ii) US$2 million upon execution of certain pending agreements with third parties, being facilitated by Blue Water. There is no time limit related to the contingent consideration. These amounts are included within other liabilities on the consolidated statements of financial position.

The transaction has been accounted for using the acquisition method in conformity with IFRS 3 Business Combinations with the results of operations included in the consolidated financial statements from the date of acquisition.

Management used assumptions and estimates about future events in the determination of fair values. The assumptions and estimates with respect to the determination of the fair value of PPE, intangible assets and contingent consideration required the most judgment. Based on those assumptions and estimates the purchase price was allocated to the identified assets and liabilities including goodwill and contingent consideration. The fair value was estimated by applying standard valuation techniques. The fair value measurement is based on significant inputs which are not observable in the market. The key assumptions in determination of fair value included the discount rate, future growth rates and expected execution of new contracts for the supply of water. The allocation of the purchase price was internally determined based on the relative fair values of the assets and liabilities. Goodwill was estimated based on the applicable incremental benefits of the acquisition. The fair value of contingent consideration was based on management's expectation of execution of new long-term water supply contracts with customers and the execution of pending agreements, discounted to their present value.

Willow Valley Water Company

On May 9, 2016, the Company completed the acquisition of the regulated water utility assets of Willow Valley Water Company, providing water services in the Bullhead City area of Arizona, U.S., for cash consideration of $3 million (US$2 million).

## 6. Revenues and other income

| | 2017 | 2016 |
|---|---|---|
| **Revenue** | | |
| Energy and water sales | $ 1,195 | $ 1,163 |
| Provision of services | 823 | 705 |
| Construction revenues | 11 | 50 |
| Other commercial revenue | 6 | 14 |
| | 2,035 | 1,932 |
| **Other income** | | |
| Interest income on long-term receivable from Capital Power | 10 | 14 |
| Other | 2 | - |
| | 12 | 14 |
| | $ 2,047 | $ 1,946 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 7. Expense analysis

| | 2017 | 2016 |
|---|---|---|
| **Included in staff costs and employee benefits expenses** | | |
| Post-employment defined contribution plan expense | $ 39 | $ 36 |
| Post-employment defined benefit plan expense | 6 | 6 |
| | | |
| **Included in depreciation and amortization** | | |
| Depreciation of property, plant and equipment | 205 | 168 |
| Amortization of intangible assets | 19 | 19 |
| Loss on disposal of assets | 12 | 2 |
| | 236 | 189 |
| | | |
| **Included in other administrative expenses** | | |
| Operating lease expenses | 15 | 16 |
| Lease recoveries through sub-lease | (5) | (6) |

## 8. Finance expenses

| | 2017 | 2016 |
|---|---|---|
| Interest on loans and borrowings | $ (121) | $ (117) |
| Capitalized interest (note 17) | 6 | 5 |
| | $ (115) | $ (112) |

## 9. Income tax recovery (expense)

| | 2017 | 2016 |
|---|---|---|
| Current income tax recovery (expense) | $ 5 | $ (4) |
| Deferred income tax recovery (expense) | | |
| Relating to origination and reversal of temporary differences | (18) | (11) |
| Change in tax rates | 20 | - |
| Recognition of previously unrecognized deferred tax assets | 7 | 6 |
| | 9 | (5) |
| Total income tax recovery (expense) | $ 14 | $ (9) |

Income taxes differ from the amounts that would be computed by applying the federal and provincial income tax rates as follows:

| | 2017 | 2016 |
|---|---|---|
| Income before taxation | $ 242 | $ 318 |
| Income tax at the statutory rate of 27% (2016 – 27%) | (65) | (86) |
| (Increase) decrease resulting from: | | |
| Income exempt from income taxes at statutory rates | 60 | 59 |
| Non-taxable amounts | - | 2 |
| Change in recognition of deferred tax assets | 7 | 18 |
| Change in tax rates on deferred taxes | 20 | - |
| Effect of higher tax rate in the U.S. | (4) | (3) |
| Other | (4) | 1 |
| Total income tax recovery (expense) | $ 14 | $ (9) |

On December 22, 2017, the U.S. Tax Cuts and Jobs Act was enacted in the U.S. Consequently, effective January 1, 2018 the U.S. federal corporate tax rate has been reduced from 35% to 21%. The change has resulted in a deferred tax recovery of $20 million related to the re-measurement of deferred tax assets and liabilities of the Company's U.S. Operations.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

### 10. Cash and cash equivalents

| | 2017 | 2016 |
|---|---|---|
| Cash on deposit | $ 181 | $ 137 |
| Cash equivalents | 157 | 54 |
| | $ 338 | $ 191 |

**Restricted balances**

Under certain agreements between the Company and the Natural Gas Exchange (NGX) for the purchase of electricity derivative financial instruments, the Company established separate bank accounts through which the settlement of the electricity derivative financial contracts are processed in conjunction with letters of credit and cash as collateral. As security for the payment and performance of its obligations, the Company assigned a first ranking security interest on the balance of these accounts to the NGX. The Company's use of this cash is restricted to these purposes. At December 31, 2017, $4 million (2016 – $2 million) was held in these bank accounts.

### 11. Trade and other receivables

| | 2017 | 2016 |
|---|---|---|
| Trade receivables | $ 224 | $ 179 |
| Accrued revenues | 141 | 125 |
| Gross accounts receivable | 365 | 304 |
| Allowance for doubtful accounts | (5) | (5) |
| Net accounts receivable | 360 | 299 |
| Income tax recoverable | 6 | 2 |
| Prepaid expenses | 7 | 6 |
| | 373 | 307 |
| Current portion of long-term receivables (note 15) | 178 | 18 |
| | $ 551 | $ 325 |

Details of the aging of accounts receivable and analysis of the changes in the allowance for doubtful accounts are provided in note 30.

### 12. Investment in Capital Power

In these consolidated financial statements, Capital Power refers to Capital Power Corporation and its subsidiaries, including Capital Power L.P., except where otherwise noted or the context indicates otherwise. Capital Power builds, owns and operates power plants in North America and manages its related electricity and natural gas portfolios by undertaking trading and marketing activity.

At December 31, 2015 the Company owned 9,391,000 common shares of Capital Power Corporation representing approximately 9% of the issued and outstanding common shares of Capital Power Corporation, which were classified as available-for-sale investment. During the year ended December 31, 2016, the Company sold 9,141,636 common shares of Capital Power Corporation for net proceeds of $204 million. The Company also reclassified fair value gains of $42 million to net income, representing the realized portion of fair value gains on available-for-sale investment in Capital Power Corporation previously recognized in other comprehensive income. The remaining 249,364 shares of Capital Power Corporation were sold during the first quarter of 2017 for net proceeds of $6 million.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

The change in available-for-sale investment in Capital Power is detailed as follows:

| | 2017 | 2016 |
|---|---|---|
| Balance, beginning of the year | $ 6 | $ 167 |
| Fair value gain recorded in other comprehensive income | - | 43 |
| Sale of investment | (6) | (204) |
| Balance, end of year | $ - | $ 6 |

## 13. Derivatives

Derivative financial instruments consist of electricity price forward contracts which are held for the purpose of electricity price risk management. The derivative financial instruments used for risk management purposes as described in note 30 consist of the following:

| | 2017 | 2016 |
|---|---|---|
| **Electricity price forward contracts** | | |
| Fair value | $ - | $ (1) |
| Cash paid to counterparty | 1 | 1 |
| Net fair value | $ 1 | $ - |
| **Net notional buys** | | |
| Terawatt hours of electricity | 1.1 | 1.1 |
| Range of contract terms (in years) | 0.1 to 0.3 | 0.1 to 0.3 |

The fair value of electricity derivative financial instruments reflects changes in the forward electricity prices, net of cash payments to or from the counterparty. During the course of the contract, daily payments are made to or received from the counterparty to settle the fair value of the contracts.

Fair value is determined based on quoted exchange index prices by reference to bid or asking price, as appropriate, in active markets. Fair value amounts reflect management's best estimates using external readily observable market data such as forward electricity prices. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Changes in fair value on electricity derivative financial instruments are recorded in energy purchases and system access fees.

## 14. Inventories

During the year ended December 31, 2017, $25 million (2016 – $25 million) was expensed to other raw materials and operating charges.

No significant inventory write-downs were recognized in the years ended December 31, 2017 or 2016. No significant reversals of previous write-downs were recorded in the years ended December 31, 2017 or 2016.

At December 31, 2017 or 2016, no inventories were pledged as security for liabilities.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 15. Other financial assets

| | 2017 | 2016 |
|---|---|---|
| Long-term loans receivable from Capital Power | $ 174 | $ 184 |
| Long-term receivables from service concession arrangements | 83 | 82 |
| Finance lease receivables | 1 | 1 |
| Loans and other long-term receivables | 10 | 15 |
| Other | 1 | 1 |
| | 269 | 283 |
| Less: current portion (included in trade and other receivables) (note 11) | 178 | 18 |
| | $ 91 | $ 265 |

**Long-term loans receivable from Capital Power**

On July 9, 2009, EPCOR received $896 million in long-term loans receivable from Capital Power as part of the consideration on the sale of the power generation business. These loans effectively mirror certain long-term debt obligations of EPCOR. The interest rates on the long-term loans receivable range from 5.8% to 9.0%. The entire long-term loans receivable balance from Capital Power is due in 2018 and has been included in trade and other receivables.

**Service concession arrangements**

The Company has executed service concession arrangements to design, build, upgrade, finance, operate and maintain, under public private partnerships, wastewater treatment facilities with the City of Regina and water and wastewater treatment facilities with Her Majesty the Queen in Right of Alberta for Kananaskis Village. The consideration under the service concession arrangements constitute rights to financial assets and have been classified as financial assets and recorded as a long-term receivable under other financial assets. The significant terms of the arrangement are summarized below:

(a) **City of Regina**

EPCOR entered into an agreement with the City of Regina to operate and maintain an existing facility and design, build, finance, operate and maintain a new wastewater treatment facility under a public private partnership, for which the contract was signed in July 2014. In August 2014, EPCOR took over the operations of the existing wastewater treatment plant in Regina. Construction of the new plant reached final completion in December, 2017. The contract includes operation of both facilities for a term of 30 years. As of December 31, 2017, an amount of $78 million (2016 – $76 million) has been recorded as a financial asset which will be recovered along with financing cost at the interest rate established in the arrangement over the life of the arrangement.

(b) **Kananaskis Village**

The Company won a bid to design, build, finance, upgrade, operate and maintain the water and wastewater treatment facilities in Kananaskis Village in October 2012. The arrangement includes operation of the facilities for a term of 10 years after completion of construction. The construction of the new facility was completed in August 2014 following which the Company started operating and maintaining the facility. At December 31, 2017, an amount of $5 million (2016 – $5 million) recognized as a financial asset pertaining to Kananaskis Village will be recovered along with financing cost at the interest rate established in the arrangement over the life of the arrangement.

The aggregate amount of revenues and operating income relating to construction services for financial assets under service concession arrangements for the year ended December 31, 2017, is $2 million (2016 – $31 million) and nil in both years, respectively.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 16. Deferred tax assets / liabilities

Deferred tax assets are attributable to the following:

| | 2017 | 2016 |
|---|---|---|
| Losses carried forward | $ 71 | $ 83 |
| Investment in partnerships | 8 | 6 |
| Canadian resource expenditures | 8 | 8 |
| Provisions | 17 | 8 |
| Deferred revenue | 67 | 108 |
| Other items | 12 | 16 |
| Tax assets | 183 | 229 |
| Set off by tax liabilities | (93) | (145) |
| Net tax assets | $ 90 | $ 84 |

Deferred tax liabilities are attributable to the following:

| | 2017 | 2016 |
|---|---|---|
| Other financial assets | $ 1 | $ 1 |
| Intangible assets and goodwill | 14 | 18 |
| Property, plant and equipment | 117 | 172 |
| Tax liabilities | 132 | 191 |
| Set off by tax assets | (93) | (145) |
| Net tax liabilities | $ 39 | $ 46 |

The changes in temporary differences during the years ended December 31, 2017 and 2016 were as follows:

| | Balance, beginning of 2017 | Recognized in net income | Recognized in OCI | Foreign currency valuation adjustment and other | Balance, end of 2017 |
|---|---|---|---|---|---|
| Losses carried forward | $ 83 | $ (10) | $ - | $ (2) | $ 71 |
| Investment in partnerships | 6 | 2 | - | - | 8 |
| Canadian resource expenditures | 8 | - | - | - | 8 |
| Provisions | 8 | 8 | - | 1 | 17 |
| Deferred revenue | 108 | (33) | - | (8) | 67 |
| Other financial assets | (1) | - | - | - | (1) |
| Intangible assets and goodwill | (18) | 2 | - | 2 | (14) |
| Property, plant and equipment | (172) | 42 | - | 13 | (117) |
| Other items | 16 | (2) | 1 | (3) | 12 |
| | $ 38 | $ 9 | $ 1 | $ 3 | $ 51 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| | Balance, beginning of 2016 | Recognized in net income | Recognized on business acquisitions | Foreign currency valuation adjustment and other | Balance, end of 2016 |
|---|---|---|---|---|---|
| Losses carried forward | $ 78 | $ 5 | $ - | $ - | $ 83 |
| Investment in partnerships | 5 | 1 | - | - | 6 |
| Canadian resource expenditures | 8 | - | - | - | 8 |
| Provisions | 8 | - | - | - | 8 |
| Deferred revenue | 106 | 4 | 1 | (3) | 108 |
| Other financial assets | (3) | 2 | - | - | (1) |
| Intangible assets and goodwill | (17) | (4) | 3 | - | (18) |
| Property, plant and equipment | (142) | (11) | (22) | 3 | (172) |
| Other items | (1) | (2) | 18 | 1 | 16 |
| | $ 42 | $ (5) | $ - | $ 1 | $ 38 |

The Company has the following deductible temporary differences for which no deferred tax assets have been recognized:

| | 2017 | 2016 |
|---|---|---|
| Non-capital losses | $ 129 | $ 106 |
| Capital losses | 279 | 280 |
| Other deductible temporary differences | - | 46 |

The Company also has taxable temporary differences of $198 million (2016 - $174 million), associated with investments in subsidiaries, for which no deferred tax liability has been recognized. In addition, no deferred tax liability has been recognized in respect of unremitted earnings of subsidiaries as the Company is in a position to control the timing of the reversal of temporary difference and it is probable that such differences will not be reversed in the foreseeable future.

The non-capital losses expire between the years 2028 and 2037.

Deferred tax assets have been recognized to the extent that it is probable that taxable income will be available against which the deductible temporary difference can be utilized. The Company has recognized deferred tax assets in the amount of $90 million (2016 – $84 million), the utilization of which is dependent on future taxable profits in excess of the profits arising from the reversal of existing taxable temporary differences. The recognition of these deferred tax assets is based on taxable income forecasts that incorporate existing circumstances that will result in positive taxable income against which non-capital loss carry-forwards can be utilized as well as management’s intention to implement specific income tax planning strategies that will allow for the offset of remaining deductible temporary differences against future earnings of taxable entities within the consolidated group.

Deferred tax assets have not been recognized in respect of $279 million (2016 - $280 million) of capital losses as it is not probable that future taxable capital gains will be available against which the Company can utilize the benefits of these losses. These losses do not expire.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

### 17. Property, plant and equipment

| | Construction work in progress | Land | Water treatment & distribution, wastewater collection & treatment | Energy transmission & distribution | Retail systems & equipment | Corporate information systems & other | Total |
|---|---|---|---|---|---|---|---|
| **Cost** | | | | | | | |
| Balance, beginning of 2017 | $ 157 | $ 48 | $ 3,764 | $ 2,466 | $ 2 | $ 58 | $6,495 |
| Additions[1] | 534 | 5 | 91 | 3 | - | 4 | 637 |
| Additions through business acquisitions | - | - | - | 83 | - | - | 83 |
| Transfers under common control transaction | 108 | 238 | 4,074 | - | - | - | 4,420 |
| Disposals and retirements | - | (8) | (28) | (23) | (1) | (6) | (66) |
| Transfers into service | (578) | - | 305 | 266 | 3 | 4 | - |
| Transfers | (5) | - | - | - | - | - | (5) |
| Foreign currency valuation adjustments | (3) | - | (73) | (5) | - | - | (81) |
| Others | - | - | 4 | - | - | - | 4 |
| Balance, end of 2017 | 213 | 283 | 8,137 | 2,790 | 4 | 60 | 11,487 |
| **Accumulated depreciation** | | | | | | | |
| Balance, beginning of 2017 | - | - | 848 | 637 | 1 | 26 | 1,512 |
| Transfers under common control transaction | - | - | 854 | - | - | - | 854 |
| Depreciation | - | - | 120 | 78 | 1 | 6 | 205 |
| Disposals and retirements | - | - | (20) | (21) | (1) | (6) | (48) |
| Foreign currency valuation adjustments | - | - | (13) | - | - | - | (13) |
| Balance, end of 2017 | - | - | 1,789 | 694 | 1 | 26 | 2,510 |
| **Net book value**, end of 2017 | $ 213 | $ 283 | $ 6,348 | $ 2,096 | $ 3 | $ 34 | $8,977 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| | Construction work in progress | Land | Water treatment & distribution, wastewater collection & treatment | Energy transmission & distribution | Retail systems & equipment | Corporate information systems & other | Total |
|---|---|---|---|---|---|---|---|
| **Cost** | | | | | | | |
| Balance, beginning of 2016 | $ 139 | $ 55 | $ 3,455 | $ 2,235 | $ 3 | $ 56 | $5,943 |
| Additions[1] | 472 | 1 | 74 | 3 | - | 4 | 554 |
| Additions through business acquisitions | - | - | 71 | - | - | - | 71 |
| Disposals and retirements | - | (8) | (14) | (22) | (1) | (4) | (49) |
| Transfers into service | (453) | - | 202 | 249 | - | 2 | - |
| Transfers | - | - | - | 1 | - | - | 1 |
| Foreign currency valuation adjustments | (1) | - | (24) | - | - | - | (25) |
| Balance, end of 2016 | 157 | 48 | 3,764 | 2,466 | 2 | 58 | 6,495 |
| **Accumulated depreciation** | | | | | | | |
| Balance, beginning of 2016 | - | - | 769 | 580 | 2 | 24 | 1,375 |
| Depreciation | - | - | 92 | 70 | - | 6 | 168 |
| Disposals and retirements | - | - | (10) | (13) | (1) | (4) | (28) |
| Foreign currency valuation adjustments | - | - | (3) | - | - | - | (3) |
| Balance, end of 2016 | - | - | 848 | 637 | 1 | 26 | 1,512 |
| **Net book value**, end of 2016 | $ 157 | $ 48 | $ 2,916 | $ 1,829 | $ 1 | $ 32 | $4,983 |

1 Additions include non-cash contributed assets of $97 million (2016 – $65 million).

Borrowing costs capitalized during the year ended December 31, 2017, were $6 million (2016 – $5 million) (note 8). The weighted average rates used to determine the borrowing costs eligible for capitalization ranged from 3.38% to 5.85% (2016 - 4.21% to 5.84%).

There are no security charges over the Company's property, plant and equipment.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 18. Intangible assets and goodwill

| | Goodwill | Customer rights | Other rights | CCN | Software | Total |
|---|---|---|---|---|---|---|
| **Cost** | | | | | | |
| Balance, beginning of 2017 | $ 52 | $ 51 | $ 78 | $ 89 | $ 174 | $ 444 |
| Additions through acquisition | - | - | - | - | 18 | 18 |
| Additions through business acquisitions | 2 | - | 2 | - | - | 4 |
| Transfers under common control transaction | - | - | - | - | 6 | 6 |
| Internally generated additions | - | - | - | - | 2 | 2 |
| Disposals and retirements | - | - | - | - | (40) | (40) |
| Change in construction work in progress | - | - | 4 | - | (2) | 2 |
| Transfers | - | - | - | - | 5 | 5 |
| Foreign currency translation adjustments | (4) | - | (4) | (5) | - | (13) |
| Balance, end of 2017 | 50 | 51 | 80 | 84 | 163 | 428 |
| **Accumulated amortization** | | | | | | |
| Balance, beginning of 2017 | - | 41 | 8 | - | 102 | 151 |
| Transfers under common control transaction | - | - | - | - | 5 | 5 |
| Amortization | - | 2 | 2 | - | 15 | 19 |
| Disposals and retirements | - | - | - | - | (40) | (40) |
| Balance, end of 2017 | - | 43 | 10 | - | 82 | 135 |
| **Net book value**, end of 2017 | $ 50 | $ 8 | $ 70 | $ 84 | $ 81 | $ 293 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| | Goodwill | Customer rights | Other rights | CCN | Software | Total |
|---|---|---|---|---|---|---|
| **Cost** | | | | | | |
| Balance, beginning of 2016 | $ 50 | $ 51 | $ 66 | $ 92 | $ 167 | $ 426 |
| Additions through acquisition | - | - | - | - | 6 | 6 |
| Additions through business acquisitions | 3 | - | 13 | - | - | 16 |
| Internally generated additions | - | - | - | - | 1 | 1 |
| Disposals and retirements | - | - | - | - | (6) | (6) |
| Change in construction work in progress | - | - | - | - | 7 | 7 |
| Transfers | - | - | - | - | (1) | (1) |
| Foreign currency translation adjustments | (1) | - | (1) | (3) | - | (5) |
| Balance, end of 2016 | 52 | 51 | 78 | 89 | 174 | 444 |
| **Accumulated amortization** | | | | | | |
| Balance, beginning of 2016 | - | 38 | 6 | - | 94 | 138 |
| Amortization | - | 3 | 2 | - | 14 | 19 |
| Disposals and retirements | - | - | - | - | (6) | (6) |
| Balance, end of 2016 | - | 41 | 8 | - | 102 | 151 |
| **Net book value**, end of 2016 | $ 52 | $ 10 | $ 70 | $ 89 | $ 72 | $ 293 |

There are no security charges over the Company's intangible assets. Included in customer rights are the Company's customer rights to operate in the FortisAlberta service territory which expire on December 31, 2020.

For purposes of impairment testing, CCN has been allocated to cash-generating units as follows:

| | 2017 | 2016 |
|---|---|---|
| **Cash generating unit:** | | |
| U.S. operations segment – Water Arizona | $ 82 | $ 86 |
| U.S. operations segment – Others | 2 | 3 |
| | $ 84 | $ 89 |

For purposes of impairment testing, goodwill acquired through business combinations has been allocated to cash-generating units as follows:

| | 2017 | 2016 |
|---|---|---|
| **Cash generating unit:** | | |
| U.S. operations segment – Water Arizona | 39 | 43 |
| Others | 11 | 9 |
| | $ 50 | $ 52 |

The most recent review of goodwill was performed in the fourth quarter for each cash generating unit. Management reviewed conditions since the last review was performed and determined that no circumstances occurred since then to require a revision to the assumptions used in the value in use calculations.

The recoverable amount of the regulated cash generating units was determined based on a value in use calculation using cash flow projections from financial budgets prepared by senior management covering a twenty year period. The recoverable amount for the non-regulated cash generating unit was calculated using the projected cash flows for the life of the project. The projections were based on cash flow projections for the most recent long-term plan, which covered periods up to ten years, with the projections for the balance of the period extrapolated using growth rates between 2.14% and 3.81% (2016 – between 1.90% and 4.43%) that are in line with the long-term average growth rate for the industry. The pre-tax discount rates applied to cash flow projections are as follows:

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| | 2017 | 2016 |
|---|---|---|
| **Cash generating unit:** | | |
| U.S. operations segment – Water Arizona | 6.52% | 7.10% |
| Others | 6.55% | 7.06% |

**Key assumptions used in value-in-use calculations**

The future cash flows of the underlying businesses are relatively stable since they relate primarily to ongoing water supply in a rate-regulated environment. In the case of cash generating units operating under a rate-regulated environment, revenues are set by the regulators to cover operating costs and to earn a return on the rate base, which is set at the regulator's approved weighted average cost of capital for the underlying utility. For non-regulated cash generating units, revenues are estimated based on long-term water supply contracts executed with the customers, which include escalation in rates and volumes over the term of the contracts.

The calculation of value in use for the cash generating units is most sensitive to the following assumptions:

**Discount rates**

The discount rates used were estimated based on the weighted average cost of capital for the cash generating unit, which, in the case of rate-regulated businesses, are the approved rate of return on capital allowed by the regulators. These rates were further adjusted to reflect the market assessment of any risk specific to the cash generating unit for which future estimates of cash flows have not been adjusted.

**Timing of future rate increases**

Revenue growth is forecast to continue at the same rate as operating costs. In the case of rate-regulated businesses, if future rate filings are delayed then rate increases and increased cash flows from revenues would be affected.

**Sensitivity to changes in assumptions**

Assumptions have been tested using reasonably possible alternative scenarios. For all scenarios considered, the recoverable value remained above the carrying amount of the cash generating unit.

## 19. Trade and other payables

| | | 2017 | | 2016 |
|---|---|---|---|---|
| Trade payables | $ | 243 | $ | 192 |
| Accrued liabilities | | 93 | | 65 |
| Accrued interest | | 30 | | 24 |
| Due to employees | | 18 | | 13 |
| Income tax payable | | - | | 5 |
| | $ | 384 | $ | 299 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 20. Loans and borrowings

### Long-term loans and borrowings

| | Effective interest rate | Principal payment terms | 2017 | 2016 |
|---|---|---|---|---|
| **Obligation to the City, net of sinking fund** | | | | |
| At 8.50%, due in 2018[1] | 11.04% | Annual installments | $ 6 | $ 13 |
| At 7.01%, due between 2018 and 2023[1] | 7.01% | Annual installments | 12 | 14 |
| At 5.20%, due between 2018 and 2034[2] | 5.36% | Bi-annual installments | 58 | 64 |
| At 3.41%, due between 2018 and 2042[3] | 3.41% | Periodic installments | 588 | - |
| | | | 664 | 91 |
| **Public debentures** | | | | |
| At 5.80%, due in 2018 | 6.02% | Due at maturity | 400 | 400 |
| At 6.80%, due in 2029 | 7.05% | Due at maturity | 150 | 150 |
| At 5.65%, due in 2035 | 5.88% | Due at maturity | 200 | 200 |
| At 6.65%, due in 2038 | 6.83% | Due at maturity | 200 | 200 |
| At 5.75%, due in 2039 | 5.88% | Due at maturity | 200 | 200 |
| At 4.55%, due in 2042 | 4.65% | Due at maturity | 300 | 300 |
| At 3.55%, due in 2047 | 3.62% | Due at maturity | 400 | - |
| | | | 1,850 | 1,450 |
| **Private debt notes** | | | | |
| Bonds at 3.74%, due in 2021 | 3.80% | Due at maturity | 173 | 185 |
| Bonds at 3.94%, due between 2018 and 2029 | 4.01% | Monthly installments | 1 | 1 |
| Bonds at 5.00%, due in 2041 | 5.08% | Due at maturity | 141 | 150 |
| Bonds at 3.63% due in 2041 | 3.71% | Due at maturity | 50 | 54 |
| | | | 365 | 390 |
| | | | 2,879 | 1,931 |
| **Other borrowings** | | | | |
| Deferred debt issue costs | | | (13) | (11) |
| Total long-term loans and borrowings | | | 2,866 | 1,920 |
| Less: current portion | | | 442 | 15 |
| | | | $ 2,424 | $ 1,905 |

### Obligation to the City

1. Debentures were initially issued by the City, on behalf of the Company, pursuant to the City Bylaw authorization. The outstanding debentures are a direct, unconditional obligation of the City. The Company's obligation to the City matches the City's obligation pursuant to those debentures and at December 31, 2017 debt obligations (net of sinking fund) totaling $18 million (2016 - $27 million) are due to the City. Out of these, debentures totaling $6 million (2016 - $13 million) rank as subordinated debt and are due to mature in year 2018.

   The Company makes annual contributions into the sinking fund of the City pertaining to certain debenture issues. These payments constitute effective settlement of the respective debt as the sinking fund accumulates to satisfy the underlying debenture maturity. For any specific City debenture sinking fund requirements, the payment obligation ceases on maturity of the debenture. The sinking fund is measured at fair value and presented net of its related debenture.

2. In 2009, the City transferred the Gold Bar wastewater treatment plant (Gold Bar) to EPCOR. Pursuant to the Gold Bar asset transfer agreement, EPCOR issued $112 million of long-term debt to the City representing EPCOR's proportionate share of the City's debt obligations in respect of Gold Bar assets.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

3. During the year, the City transferred the Drainage business to the Company. Pursuant to the transfer of Drainage business, the Company issued a promissory note to the City having fair value of $604 million on the date of transfer (note 5).

Except for the subordinated debt, the obligation to the City will rank at least equal to all current and future senior unsecured debt that may be issued by the Company.

**Public debentures**

During the year, the Company issued public debentures totaling $400 million maturing in 2047 at an interest rate of 3.55%. The public debentures are unsecured direct obligations of the Company and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Company. The debentures are redeemable by the Company prior to maturity at the greater of par and a price specified under the terms of the debenture.

**Private debt notes**

The private debt notes issued in U.S. dollars, are unsecured direct obligations of the Company and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Company. The private debt notes are redeemable by the Company prior to maturity at the greater of par and a price specified under the terms of the private debt notes.

**21. Deferred revenue**

| | | 2017 | | 2016 |
|---|---|---|---|---|
| Balance, beginning of year | $ | 1,041 | $ | 991 |
| Contributions received | | 133 | | 83 |
| Revenue recognized | | (38) | | (37) |
| Transfers from provisions | | 10 | | 10 |
| Recognized on business acquisition | | - | | 1 |
| Recognized on transfer of business | | 2,152 | | - |
| Foreign currency valuation adjustments | | (17) | | (7) |
| | | 3,281 | | 1,041 |
| Less: current portion | | 60 | | 25 |
| Balance, end of year | $ | 3,221 | $ | 1,016 |

Contributions received include non-cash contributions of $85 million (2016 – $62 million).

**22. Provisions**

| | | 2017 | | 2016 |
|---|---|---|---|---|
| Contributions from customers and developers | $ | 19 | $ | 21 |
| Employee benefits | | 95 | | 89 |
| Other | | 2 | | 1 |
| | | 116 | | 111 |
| Less: current portion | | 25 | | 25 |
| | $ | 91 | $ | 86 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

**Contributions from customers and developers**

| | 2017 | 2016 |
|---|---|---|
| Balance, beginning of year | $ 21 | $ 23 |
| Contributions received | 13 | 13 |
| Transfers to deferred revenue | (10) | (10) |
| Contributions refunded | (3) | (3) |
| Foreign currency valuation adjustment | (2) | (2) |
| Balance, end of year | $ 19 | $ 21 |

Contributions received include non-cash contributions of $12 million (2016 – $3 million).

**Employee benefits**

| | 2017 | 2016 |
|---|---|---|
| Other short-term employee benefit obligation | $ 18 | $ 18 |
| Post-employment benefit obligation | 57 | 51 |
| Other long-term employee benefit obligation | 20 | 20 |
| | $ 95 | $ 89 |

**Post-employment benefits**

Total cash payments for pension benefits for the year ended December 31, 2017, consisting of cash contributed by the Company to the LAPP, other defined contribution and benefit plans, and cash payments directly to beneficiaries for their unfunded pension plan, were $42 million (2016 – $39 million). Total contributions expected to be paid in 2018 to the LAPP, other defined contribution and benefit plans, and cash payments directly to beneficiaries for their unfunded pension plan are $40 million.

**Other long-term employee benefits**

Other long-term employee benefits consist mainly of obligations for benefits provided to employees on long-term disability leaves.

## 23. Other liabilities

| | 2017 | 2016 |
|---|---|---|
| Customer deposits | $ 29 | $ 26 |
| Drainage transition cost compensation | 65 | - |
| Contingent consideration | 43 | 36 |
| Leasehold inducements | 9 | 10 |
| | 146 | 72 |
| Less: current portion | 50 | 26 |
| | $ 96 | $ 46 |

**Drainage transition cost compensation**

The Drainage transition cost compensation represents the Company's commitment to the City to pay for the stranded cost including liabilities retained by the City relating to Drainage business (note 5). The change in the liability for Drainage transition cost compensation is as follows:

| | 2017 |
|---|---|
| Fair value of transition cost compensation recognized on transfer of Drainage | $ 72 |
| Payment during the year | (8) |
| Unwinding of interest included within finance expenses | 1 |
| | $ 65 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

**Contingent consideration**

The contingent consideration is the present value of the Company's commitment to pay approximately US$34 million on securing newly executed long-term contracts for the supply of water by EPCOR 130 Project Inc. and approximately US$8 million on securing additional customer connections for natural gas by Hughes (note 5). The Company is reasonably certain that it will be required to settle this commitment by way of cash payments and has accordingly recognized the liability for contingent consideration in the consolidated statements of financial position. The change in the liability for contingent consideration is as follows:

| | 2017 | 2016 |
|---|---|---|
| Contingent consideration recognized on business acquisition | $ 36 | $ 34 |
| Recognized on business acquisition | 8 | - |
| Unwinding of interest included in finance expenses | 2 | - |
| Foreign currency valuation adjustments | (3) | 2 |
| | $ 43 | $ 36 |

## 24. Share capital

**Authorized shares**

Unlimited number of voting common shares without nominal or par value.

**Issued shares**

Three common shares to the City.

**Capital contributions**

Share capital includes capital contributions received from the City. During the year, the Company received capital contribution of $788 million on transfer of Drainage from the City (note 5). As of December 31, 2017 the Company had accumulated capital contributions of $812 million (2016 - $24 million).

## 25. Accumulated other comprehensive income

**Available-for-sale financial assets**

This comprises the cumulative net change in the fair value of the Company's beneficial interest in the sinking fund and investment in Capital Power Corporation, until the investments are derecognized or impaired.

**Cumulative translation account**

The cumulative translation account represents the cumulative portion of gains and losses on retranslation of foreign operations that have a functional currency other than Canadian dollars. The cumulative deferred gain or loss on the foreign operation is reclassified to net income only on disposal of the foreign operation.

**Employee benefits account**

The employee benefits account represents the cumulative impact of actuarial gains and losses, and return on plan assets excluding interest income from the Company's defined benefit pension plans.

## 26. Change in non-cash working capital

| | 2017 | 2016 |
|---|---|---|
| Trade receivables (note 11) | $ (65) | $ 34 |
| Prepaid expenses (note 11) | (1) | (1) |
| Inventories | (3) | 1 |
| Trade and other payables (note 19) | 85 | 40 |
| | $ 16 | $ 74 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| | 2017 | 2016 |
|---|---|---|
| Included in specific items on consolidated statements of cash flows: | | |
| Interest paid | $ - | $ (2) |
| Income taxes recovered | (9) | 5 |
| Business acquisitions | (2) | - |
| Distributions received from Capital Power | - | 3 |
| | (11) | 6 |
| Transfers under common control transaction | (52) | - |
| Operating activities | 48 | 63 |
| Investing activities | 31 | 5 |
| | $ 16 | $ 74 |

**27. Changes in liabilities arising from financing activities:**

| | At December 31, 2016 | Issued or received | Redemptions, repayments or payments | Foreign currency valuation adjustment | Other | At December 31, 2017 |
|---|---|---|---|---|---|---|
| Long-term loans and borrowings (including current portion): | | | | | | |
| Obligation to the City, net of sinking fund | $ 91 | $ - | $ (24) | $ - | $ 597 | $ 664 |
| Public debentures | 1,450 | 400 | - | - | - | 1,850 |
| Private debt notes | 390 | - | (13) | (26) | 14 | 365 |
| Deferred debt issuance costs | (11) | (2) | - | - | - | (13) |
| Total long-term loans and borrowings (including current portion) | $ 1,920 | $ 398 | $ (37) | $ (26) | $ 611 | $ 2,866 |
| Short-term loans and borrowings | $ - | $ 461 | $ (461) | $ - | $ - | $ - |
| Contributions from customers and developers | $ 21 | $ 1 | $ (3) | $ (2) | $ 2 | $ 19 |

| | At December 31, 2015 | Issued or received | Redemptions, repayments or payments | Foreign currency valuation adjustment | Other | At December 31, 2016 |
|---|---|---|---|---|---|---|
| Long-term loans and borrowings (including current portion): | | | | | | |
| Obligation to the City, net of sinking fund | $ 105 | $ - | $ (11) | $ - | $ (3) | $ 91 |
| Public debentures | 1,580 | - | (130) | - | - | 1,450 |
| Private debt notes | 346 | 52 | - | (9) | 1 | 390 |
| Deferred debt issuance costs | (12) | - | - | - | 1 | (11) |
| Total long-term loans and borrowings (including current portion) | $ 2,019 | $ 52 | $ (141) | $ (9) | $ (1) | $ 1,920 |
| Short-term loans and borrowings | $ 98 | $ 1,199 | $ (1,297) | $ - | $ - | $ - |
| Contributions from customers and developers | $ 23 | $ 10 | $ (3) | $ (2) | $ (7) | $ 21 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 28. Related party balances and transactions

### Compensation of key management personnel

| | 2017 | 2016 |
|---|---|---|
| Short-term employee benefits | $ 5 | $ 5 |
| Post-employment benefits | 1 | 1 |
| Other long-term benefits | 2 | 2 |
| | $ 8 | $ 8 |

The Company provides utility services to key management personnel as it is the sole provider of certain services. Such services are provided in the normal course of operations and are based on normal commercial rates, as approved by regulation.

### Other related party transactions

The Company is 100% owned by the City. The Company provides maintenance, repair and construction services, and customer billing services to the City, and purchases printing services and supplies, mobile equipment services, public works and various other services pursuant to service agreements. Sales between the Company and the City are in the normal course of operations, and are generally based on normal commercial rates, or as agreed to by the parties.

The following summarizes the Company's related party transactions with the City except for the transfer of Drainage and related transactions which have been disclosed in detail in note 5:

| | 2017 | 2016 |
|---|---|---|
| **Consolidated Statements of Comprehensive Income** | | |
| Revenues (a) | $ 87 | $ 94 |
| Other raw materials and operating charges (b) | 16 | 8 |
| Other administrative expenses (c) | 3 | 2 |
| Franchise fees and property taxes (d) | 104 | 92 |
| Finance expense (e) | 15 | 9 |

(a) Included within revenues are electricity and water sales of $4 million (2016 – $4 million), service revenue including the provision of maintenance, repair and construction services of $76 million (2016 – $82 million) and customer billing services of $7 million (2016 – $8 million).

(b) Includes certain costs of waste management and planning services, mobile equipment services, public works and various other services pursuant to service agreements.

(c) Incudes certain costs of cash processing service, corporate services for Drainage operations and various other services pursuant to service agreements.

(d) Composed of franchise fees of $63 million at 0.43 cents per kilowatt hour of electric distribution sales volume for direct connect customers and 0.84 cents per kilowatt hour for all other customers (2016 - $57 million at 0.39 cents per kilowatt hour of electric distribution sales volume for direct connect customers and 0.76 cents per kilowatt hour for all other customers), franchise fees of $21 million at 8% (2016 – $20 million at 8%) of qualifying revenues of water services and waste water services, franchise fees of $3 million at 8% of qualifying revenue of sanitary services, property taxes of $16 million (2016 - $15 million) on properties owned within the City municipal boundaries and business tax of $ $1 million (2016 – nil).

(e) Composed of interest expense on the obligation to the City at interest rates ranging from 3.41% to 8.50% (2016 – 5.20% to 8.50%).

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

The following summarizes the Company's related party balances with the City:

| | 2017 | 2016 |
|---|---|---|
| **Consolidated Statements of Financial Position** | | |
| Trade and other receivables | $ 46 | $ 34 |
| Property, plant and equipment (f) | 4 | 5 |
| Trade and other payables | 44 | 8 |
| Loans and borrowings (note 20) | 664 | 91 |
| Deferred revenue (g) | - | 2 |
| Other liabilities (note 23) | 65 | - |

(f) Costs of capital construction for electric and water distribution infrastructure.

(g) Contributions received for capital projects.

## 29. Financial instruments

### Classification

The classification of the Company's financial instruments at December 31, 2017 and 2016 is summarized as follows:

| | Classification | | | | |
|---|---|---|---|---|---|
| | Fair value through profit or loss | Loans and receivables | Other financial liabilities | Available-for-sale | Fair value hierarchy |
| **Measured at fair value** | | | | | |
| Available-for-sale investment in Capital Power (note 12) | | | | X | Level 1 |
| Derivatives (note 13) | X | | | | Level 1 |
| Beneficial interest in sinking fund (note 20) | | | | X | Level 1 |
| Other liabilities (note 23) | | | | | |
| Contingent consideration – designated | X | | | | Level 3 |
| **Measured at amortized cost** | | | | | |
| Cash and cash equivalents (note 10) | | X | | | Level 1 |
| Trade and other receivables (note 11) | | X | | | Level 3 |
| Other financial assets (note 15) | | X | | | Level 2 |
| Trade and other payables (note 19) | | | X | | Level 3 |
| Debentures and borrowings (note 20) | | | X | | Level 2 |
| Other liabilities (note 23) | | | | | |
| Customer deposits | | | X | | Level 3 |
| Drainage transition cost compensation | | | X | | Level 2 |

### Fair value

The carrying amounts of cash and cash equivalents, trade and other receivables, current portion of other financial assets, trade and other payables and certain other liabilities (including customer deposits) approximate their fair values due to the short-term nature of these financial instruments.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

The carrying amounts and fair values of the Company's remaining financial assets and liabilities are as follows:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| | Carrying Amount | Fair value | Carrying Amount | Fair value |
| Available-for-sale investment in Capital Power (note 12) | $ - | $ - | $ 6 | $ 6 |
| Derivatives (note 13) | 1 | 1 | - | - |
| Non-current portion of other financial assets (note 15)[1] | 90 | 99 | 264 | 275 |
| Long-term loans and borrowings including current portion (note 20) | | | | |
| Debentures and borrowings | 2,960 | 3,326 | 2,007 | 2,328 |
| Beneficial interest in sinking fund | (94) | (94) | (87) | (87) |
| Other liabilities (note 23) | | | | |
| Contingent consideration | 43 | 43 | 36 | 36 |
| Drainage transition cost compensation | 65 | 65 | - | - |

1 Excluding finance lease receivables $1 million (2016 – $1 million).

*Fair value hierarchy*

The financial instruments of the Company that are recorded at fair value have been classified into levels using a fair value hierarchy. A Level 1 valuation is determined by unadjusted quoted prices in active markets for identical assets or liabilities. A Level 2 valuation is based upon inputs other than quoted prices included in Level 1 that are observable for the instruments either directly or indirectly. A Level 3 valuation for the assets and liabilities are not based on observable market data.

*Available-for-sale investment in Capital Power*

The available-for-sale investment in Capital Power represents an investment in common shares of Capital Power Corporation. The fair value of the investment is based on the quoted price of common shares of Capital Power Corporation (CPX) on the Toronto Stock Exchange at December 31, 2016. During the first quarter of 2017 the remainder of this investment was disposed.

*Derivatives*

The fair value of the Company's financial electricity purchase contracts is determined based on exchange index prices in active markets. Fair value amounts reflect management's best estimates using external readily observable market data such as forward electricity prices.

It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

*Other financial assets*

The fair value of the Company's unsecured long-term receivable from Capital Power is based on a current yield for the Company's receivable at December 31, 2017 and 2016. This yield is based on an estimated credit spread for Capital Power over the yields of long-term Government of Canada bonds that have similar maturities to the Company's receivable. The estimated credit spread is based on Capital Power's indicative spread as published by independent financial institutions. As of December 31, 2017 the remaining long-term receivable from Capital Power of $174 million has be classified as current asset under trade and other receivables. Due to short-maturity of receivable, the carrying value approximates the fair value.

The fair values of the Company's other long-term loans and receivables are based on the estimated interest rates implicit in comparable loan arrangements plus an estimated credit spread based on the counterparty risks at December 31, 2017 and 2016.

*Long-term loans and borrowings including current portion*

The fair value of the Company's long-term public debt is based on the pricing sourced from market data as of December 31, 2017 and 2016. The fair value of the Company's remaining long-term loans and borrowings is based on determining a current yield for the Company's debt at December 31, 2017 and 2016. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada bonds for Canadian dollar loans and U.S. Treasury bonds for U.S. dollar loans that have similar maturities to the Company's debt. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions. The Company's long-term loans and borrowings include City debentures which are partially offset by payments made by the Company into the sinking fund. The Company's beneficial interest in the sinking fund is a related party balance and has been recorded at fair value as it has been classified as an available-for-sale financial asset in accordance with the requirements of IFRS. The fair value of the beneficial interest in the sinking fund is based on quoted market values as determined by the City at or near the reporting date.

*Contingent consideration*

The contingent consideration is payable in U.S. dollars and payment is dependent on securing newly executed long-term contracts for the supply of water by EPCOR 130 Project Inc. and additional customer connections for natural gas by Hughes, the timing of which is uncertain. The fair value of the Company's contingent consideration is determined based on the expected timing of securing such new contracts and customer connections and the resulting cash flows are then discounted at risk adjusted discount rates. Any change in the timing of execution of new contracts, discount rate or foreign exchange rate can have material impact on the fair value of contingent consideration.

Timing of securing new contracts / additional customer connections

If the timing of securing new contracts / additional customer connections is advanced by 2 years then the fair value of the contingent consideration will increase by $6 million (2016 - $5 million). Alternatively, if the timing of securing new contracts / additional customer connections is delayed by 2 years then the fair value of the contingent consideration will decrease by $4 million (2016 - $4 million).

Discount rate

A 50 basis point increase in discount rate will decrease the fair value of the contingent consideration by $nil (2016 - $1 million). Alternatively 50 basis point decrease in discount rate will increase the fair value of contingent consideration by $1 million (2016 - $1 million).

Foreign exchange rate

A 10% change in the foreign exchange rate will change the fair value of the contingent consideration by $4 million (2016 - $4 million).

## 30. Financial risk management

### Overview

The Company is exposed to a number of different financial risks arising from business activities and its use of financial instruments, including market risk, credit risk, and liquidity risk. The Company's overall risk management process is designed to identify, assess, measure, manage, mitigate and report on business risk which includes financial risk. Enterprise risk management is overseen by the Board of Directors and senior management is responsible for fulfilling objectives, targets, and policies approved by the Board of Directors. EPCOR's Director, Audit and Risk Management provide the Board of Directors with an enterprise risk assessment quarterly. Risk management strategies, policies and limits are designed to help ensure the risk exposures are managed within the Company's business objectives and risk tolerance. The Company's financial risk management objective is to protect and minimize volatility in earnings and cash flow.

Financial risk management including foreign exchange risk, interest rate risk, liquidity risk and the associated credit risk management is carried out by the centralized Treasury function in accordance with applicable policies. The Audit Committee of the Board of Directors, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help ensure compliance.

**Risks related to Capital Power**

Significant reliance is placed on the capacity of Capital Power to honor its back-to-back debt obligations with EPCOR. Should Capital Power fail to satisfy these obligations, EPCOR's capacity to satisfy its debt obligations would be reduced and EPCOR would need to satisfy its own debt obligations by other means. The outstanding balance of back-to-back debt receivable from Capital Power is due by June 30, 2018.

Capital Power has indemnified EPCOR for any losses arising from its inability to discharge its liabilities, including any amounts owing to EPCOR in relation to the long-term loans receivable.

**Market risk**

Market risk is the risk of loss that results from changes in market factors such as electricity prices, foreign currency exchange rates and interest rates. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Company's financial assets and liabilities held, non-trading physical asset and contract portfolios, and trading portfolios. The Company's financial exposure management policy is approved by the Board of Directors and the associated procedures and practices are designed to manage the foreign exchange and interest rate risk throughout the Company.

To manage the exposure related to changes in market risk, the Company may use various risk management techniques including derivative financial instruments such as forward contracts, contracts-for-differences or interest rate swaps. Such instruments may be used for an anticipated transaction to establish a fixed price denominated in a foreign currency or to secure electricity price or to secure fixed interest rates.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonable changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these instruments. The Company's actual exposure to market risks is constantly changing as the Company's portfolio of debt, foreign currency and commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Company.

*Electricity price and volume risk*

EPCOR sells electricity to regulated rate option (RRO) customers under a RRT. All electricity for the RRO customers is purchased in real time from the AESO in the spot market. Under the RRT, the amount of electricity to be economically hedged, the hedging method and the electricity selling prices to be charged to these customers is determined by the EPSP. Under the EPSP, the Company uses financial contracts to economically hedge the RRO requirements and incorporate the price into customer rates for the applicable month. Fixed volumes of electricity are economically hedged using financial contracts-for-differences in advance of the month in which the electricity (load) is consumed by the RRO customers. The volume of electricity economically hedged in advance is based on load (usage) forecasts for the consumption month. When consumption varies from forecast consumption patterns, EPCOR is exposed to prevailing market prices when the volume of electricity economically hedged is short of actual load requirements or greater than the actual load requirements (long). Exposure to variances in electricity volume can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

Under contracts-for-differences the Company agrees to exchange, with a single creditworthy and adequately secured counterparty, the difference between the AESO electricity spot market price and the fixed contract price for a specified volume of electricity in advance of the consumption date, all in accordance with the EPSP. The contracts-for-differences are referenced to the AESO electricity spot price and any movement in the AESO price results in changes in the contract settlement amount. If the risks of the EPSP were to become untenable, EPCOR could test the market and potentially re-contract the procurement risk under an outsourcing arrangement at a certain cost that would likely increase procurement costs and reduce margins. The Company may enter into additional financial electricity purchase contracts outside the EPSP to further economically hedge the price of electricity.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

At December 31, 2017, holding all other variables constant, a $5 per megawatt hour increase / decrease in the forward electricity spot price would increase / decrease net income by approximately $5 million (2016 – $5 million). In preparing the sensitivity analysis, the Company compared average AESO electricity spot prices to the forward index price for the past 24 months. Based on historical fluctuations, the Company estimates that the fair value of the contracts could increase or decrease by up to $6 million (2016 – $22 million) with a corresponding change to net income.

*Foreign exchange risk*

The Company is exposed to foreign exchange risk on foreign currency denominated future transactions and firm commitments, and monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign subsidiaries.

The Company's financial exposure management policy attempts to minimize material exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company's direct exposure to foreign exchange risk arises on commitments denominated in U.S. dollars or other currencies. The Company coordinates and manages foreign exchange risk centrally by identifying opportunities for naturally occurring opposite movements and then dealing with any material residual foreign exchange risks.

The Company may use foreign currency forward contracts to fix the functional currency of its non-functional currency cash flows thereby reducing its anticipated foreign currency denominated transactional exposure. The Company looks to limit foreign currency exposures as a percentage of estimated future cash flows.

At December 31, 2017, holding all other variables constant, a 10% change in exchange rate would change the private debt balance by $36 million (2016 – $39 million).

*Interest rate risk*

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating-rate short-term loans and obligations. The Company is also exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. At December 31, 2017 and 2016, all long-term debt was fixed rate.

**Credit risk**

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company, including payment and performance. The Company's counterparty credit risk management policy is approved by the Board of Directors and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to senior management. Creditworthiness continues to be evaluated after transactions have been initiated, at a minimum, on an annual basis. Credit risk includes the Capital Power back-to-back debt obligations with EPCOR as described above. To manage and mitigate credit risk, the Company employs various credit mitigation practices such as master netting agreements, pre-payment arrangements from retail customers, credit derivatives and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

*Maximum credit risk exposure*

The Company's maximum credit exposure is represented by the carrying amount of the following financial assets:

| | 2017 | 2016 |
|---|---|---|
| Cash and cash equivalents[1] (note 10) | $ 338 | $ 191 |
| Trade and other receivables[1 & 2] (note 11) | 360 | 299 |
| Other financial assets (note 15) | 269 | 283 |
| | $ 967 | $ 773 |

1 This table does not take into account collateral held. At December 31, 2017, the Company held cash deposits of $29

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

million (2016 – $26 million) as security for certain counterparty accounts receivable and derivative contracts. The Company is not permitted to sell or re-pledge this collateral in the absence of default of the counterparties providing the collateral.

2 The Company's maximum exposures related to trade and other receivables by major credit concentration is composed of $282 million (2016 – $212 million) related to rate-regulated customer balances. At December 31, 2017, the Company held credit enhancements to mitigate credit risk on trade and other receivables in the form of letters of credit of $1 million (2016 – $1 million), performance bonds of $1 million (2016 – $1 million) and parental guarantees of $254 million (2016 – $263 million).

*Credit quality and concentrations*

The Company is exposed to credit risk on outstanding trade receivables associated with its energy and water sales activities and agreements with the AESO and on electricity supply agreements with wholesale and retail customers. The Company is also exposed to credit risk from its cash and cash equivalents, derivative instruments and long-term financing arrangements receivable.

The credit quality of the Company's trade and other receivables, by major credit concentrations, finance lease receivables, and other financial assets at December 31, 2017 and 2016, was as follows:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| | Investment grade or secured[1,2] % | Unrated % | Investment grade or secured[1,2] % | Unrated % |
| **Trade and other receivables** | | | | |
| Rate-regulated customers[3] | 3 | 70 | - | 65 |
| Non rate-regulated customers | 22 | 5 | 24 | 11 |
| **Total trade and other receivables** | 25 | 75 | 24 | 76 |
| **Cash and cash equivalents** | 100 | - | 100 | - |
| **Loans and other long-term receivables** | 100 | - | 100 | - |

1 Credit ratings are based on the Company's internal criteria and analyses, which take into account, among other factors, the investment grade ratings of external credit rating agencies when available.

2 Certain trade receivables and other financial assets are considered to have low credit risk as they are either secured by the underlying assets, secured by other forms of credit enhancements, or the counterparties are local or provincial governments.

3 Rate-regulated customer trade receivables include energy distribution and transmission, water sales, collection and conveyance of sanitary and stormwater, treatment of wastewater, rate-regulated and default electricity supply receivables. Under the Electric Utilities Act (Alberta), the Company provides electricity supply in its service area to residential, agricultural and small commercial customers at regulated rates and to those commercial and industrial customers who have not chosen a competitive offer and consume electricity under default supply arrangements.

*Rate-regulated customer credit risk*

Credit risk exposure for residential and commercial customers under regulated electricity and water supply rates is generally limited to amounts due from customers for electricity and water consumed but not yet paid for. The Company mitigates credit risk from counterparties by performing credit checks and on higher risk customers, by taking pre-payments or cash deposits. The Company monitors credit risk for this portfolio at the gross exposure level.

*Trade and other receivables and allowance for doubtful accounts*

Trade and other receivables consist primarily of amounts due from retail customers including commercial customers, other retailers, government-owned or sponsored entities, regulated public utility distributors, and other counterparties. Commercial customer contracts provide performance assurances through letters of credit, irrevocable guarantees and bonds. For other retail customers, represented by a diversified customer base, credit losses are generally low and the

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

Company provides for an allowance for doubtful accounts on estimated credit losses.

The aging of accounts receivables was as follows:

| December 31, 2017 | Gross accounts receivables | Allowance for doubtful accounts | Net accounts receivables |
|---|---|---|---|
| Current[1] | $ 327 | $ - | $ 327 |
| Outstanding 31 to 60 days | 16 | - | 16 |
| Outstanding 61 to 90 days | 9 | 2 | 7 |
| Outstanding more than 90 days | 13 | 3 | 10 |
| | $ 365 | $ 5 | $ 360 |

| December 31, 2016 | Gross accounts receivables | Allowance for doubtful accounts | Net accounts receivables |
|---|---|---|---|
| Current[1] | $ 279 | $ - | $ 279 |
| Outstanding 31 to 60 days | 11 | - | 11 |
| Outstanding 61 to 90 days | 5 | 2 | 3 |
| Outstanding more than 90 days | 9 | 3 | 6 |
| | $ 304 | $ 5 | $ 299 |

1 Current amount represents trade and other receivables outstanding up to 30 days. Amounts outstanding for more than 30 days are considered past due.

Bad debt expense of $7 million (2016 – $9 million) recognized in the year relates to customer amounts that the Company determined may not be fully collectable. Allowances for doubtful accounts are determined by each business unit considering the unique factors of the business unit's trade and other receivables. Allowances and write-offs are determined either by applying specific risk factors to customer groups' aged balances in trade and other receivables or by reviewing material accounts on a case-by-case basis. Reductions in trade and other accounts receivable and the related allowance for doubtful accounts are recorded when the Company has determined that recovery is not possible.

The change in the allowance for doubtful accounts was as follows:

| | 2017 | 2016 |
|---|---|---|
| Balance, beginning of year | $ 5 | $ 3 |
| Additional allowances created | 7 | 9 |
| Recovery of receivables | 1 | 2 |
| Receivables written off | (8) | (9) |
| Balance, end of year | $ 5 | $ 5 |

At December 31, 2017, the Company held $30 million (2016 – $24 million) of customer deposits for the purpose of mitigating the credit risk associated with trade and other receivables from residential and business customers.

**Liquidity risk**

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's liquidity is managed centrally by the Company's Treasury function. The Company manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities and financings in public or private debt capital markets.

In the normal course of business, the Company provides financial support and performance assurances including guarantees, letters of credit and surety bonds to third parties in respect of its subsidiaries. The Company has revolving extendible credit facilities, which are used principally for the purpose of backing the Company's commercial paper program and providing letters of credit, as outlined below:

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| **December 31, 2017** | Expiry | Total facilities | Banking commercial paper issued | Letters of credit and other facility draws | Net amounts available |
|---|---|---|---|---|---|
| **Committed** | | | | | |
| Syndicated bank credit facility[1] | November 2022 | $ 600 | $ - | $ - | $ 600 |
| **Uncommitted** | | | | | |
| Bank credit facilities[2] | No expiry | 200 | - | 66 | 134 |
| Bank credit facility | No expiry | 25 | - | - | 25 |
| Total uncommitted | | 225 | - | 66 | 159 |
| | | $ 825 | $ - | $ 66 | $ 759 |

| **December 31, 2016** | Expiry | Total facilities | Banking commercial paper issued | Letters of credit and other facility draws | Net amounts available |
|---|---|---|---|---|---|
| **Committed** | | | | | |
| Syndicated bank credit facility[1] | November 2020 | $ 350 | $ - | $ - | $ 350 |
| Syndicated bank credit facility[2] | November 2019 | 200 | - | 73 | 127 |
| Total committed | | 550 | - | 73 | 477 |
| **Uncommitted** | | | | | |
| Bank credit facility | No expiry | 25 | - | - | 25 |
| | | $ 575 | $ - | $ 73 | $ 502 |

1 In November 2017, the Company established a new $600 million single tranche committed syndicated bank credit facility which replaced the previous $350 million single tranche committed syndicated bank credit facility. The Company's $600 million committed syndicated bank credit facility is available and primarily used for short-term borrowing and backstopping EPCOR's commercial paper program. The committed syndicated bank credit facility cannot be withdrawn by the lenders until expiry, provided that the Company operates within the related terms and covenants. The extension feature of EPCOR's committed syndicated bank credit facility give the Company the option each year to re-price and extend the terms of the facility by one or more years subject to agreement with the lending syndicate. The Company regularly monitors market conditions and may elect to enter into negotiations to extend the maturity dates.

2 In November 2017 the Company established five new bilateral credit facilities (totaling $200 million) which replaced the previous $200 million committed syndicated bank credit facility. The Company's uncommitted line of credit is restricted to letters of credit. At December 31, 2017 Letters of credit totaling $66 million have been issued and outstanding under uncommitted line of credit (2016 – $73 million issued under committed syndicated bank credit facility) to meet the credit requirements of electricity market participants and to meet conditions of certain service agreements. Amounts borrowed and letters of credit issued, if any, under these facilities which are not payable within one year are classified as non-current loans and borrowings.

The Company has credit ratings of A- and A (low), assigned by Standard and Poor's and DBRS Limited, respectively.

The Company has a Canadian base shelf prospectus under which it may raise up to $2 billion of debt with maturities of not less than one year. At December 31, 2017, the available amount remaining under this Canadian base shelf prospectus was $2 billion. The Canadian base shelf prospectus expires in December 2019.

The undiscounted cash flow requirements and contractual maturities of the Company's non-derivative financial liabilities, including interest payments, are as follows:

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

At December 31, 2017:

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 and thereafter | Total contractual cash flows |
|---|---|---|---|---|---|---|---|
| Trade and other payables[1] | $ 354 | $ - | $ - | $ - | $ - | $ - | $ 354 |
| Loans and borrowings[2] | 442 | 32 | 33 | 207 | 34 | 2,131 | 2,879 |
| Interest payments on loans and borrowings | 131 | 112 | 111 | 109 | 102 | 1,547 | 2,112 |
| Other liabilities[3] | 50 | 23 | 58 | 15 | 7 | 4 | 157 |
| | $ 977 | $ 167 | $ 202 | $ 331 | $ 143 | $ 3,682 | $ 5,502 |

At December 31, 2016:

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 and thereafter | Total contractual cash flows |
|---|---|---|---|---|---|---|---|
| Trade and other payables[1] | $ 275 | $ - | $ - | $ - | $ - | $ - | $ 275 |
| Loans and borrowings[2] | 15 | 413 | 7 | 7 | 192 | 1,297 | 1,931 |
| Interest payments on loans and borrowings | 112 | 100 | 80 | 79 | 79 | 1,141 | 1,591 |
| Other liabilities[3] | 26 | 3 | 1 | 44 | 1 | 7 | 82 |
| | $ 428 | $ 516 | $ 88 | $ 130 | $ 272 | $ 2,445 | $ 3,879 |

1 Excluding accrued interest on loans and borrowings of $30 million (2016 – $24 million).
2 Excluding deferred debt issue costs of $13 million (2016 – $11 million).
3 Includes undiscounted liabilities for contingent consideration and Drainage transition cost compensation.

The Company's undiscounted cash flow requirements and contractual maturities in the next twelve months of $977 million (2016 – $428 million) are expected to be funded from operating cash flows, interest and principal payments related to the unsecured long-term receivable from Capital Power, commercial paper issuance and the Company's credit facilities. In addition, the Company may issue medium-term notes or other instruments to fund its obligations or investments. The key factors in determining whether to issue medium-term notes are the cash requirements of the business, the expected interest rates for medium-term notes, the estimated demand by investors for EPCOR debt and the general state of debt capital markets.

The Company has long-term loans receivable from Capital Power which effectively match certain of the long-term loans and borrowings above. The remaining long-term loans receivable from Capital Power totaling $174 million is due by June 30, 2018 along with interest payment of $6 million.

The payments from Capital Power fund a portion of the Company's contractual debt obligations. Should Capital Power be unable to make its scheduled payments to EPCOR, then the Company will rely more heavily on its credit facilities and its ability to issue medium-term notes to fund its obligations.

## 31. Capital management

The Company’s primary objectives when managing capital are to safeguard the Company’s ability to continue as a going concern, pay dividends to its shareholder in accordance with the Company’s dividend policy, maintain an investment grade credit rating, and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the Company's growth strategy. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. This overall objective and policy for managing capital remained unchanged in the current year from the prior year.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Company considers its capital structure to consist of long-term and short-term debt net of cash and cash equivalents and shareholder's equity. The following table represents the Company's total capital:

| | 2017 | 2016 |
|---|---|---|
| Long-term Loans and borrowings (including current portion) (note 20)[1] | $ 2,879 | $ 1,931 |
| Cash and cash equivalents (note 10) | (338) | (191) |
| Net debt | 2,541 | 1,740 |
| Total equity | 3,526 | 2,672 |
| Total capital | $ 6,067 | $ 4,412 |

1 Excluding deferred debt issue costs of $13 million (2016 – $11 million).

EPCOR has the following externally imposed financial covenants on its capital as a result of its credit facilities and outstanding debt:

- Maintenance of modified consolidated net tangible assets to consolidated net tangible assets ratio, as defined in the debt agreements, of not less than 80% (2016 – 80%);
- Maintenance of consolidated senior debt to consolidated capitalization ratio, as defined in the debt agreements, of not more than 75% (2016 – 75%) ;
- Maintenance of interest coverage ratio, as defined in the debt agreements of not less than 1.75 to 1.00 is not applicable as the Company has a debt rating of investment grade; and
- Limitation on external debt issued by subsidiaries.

These capital restrictions are defined in accordance with the respective agreements. For the years ended December 31, 2017 and 2016, the Company complied with all externally imposed capital restrictions.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

## 32. Commitments, contingencies and guarantees

### Commitments

The following represent the Company's commitments not otherwise disclosed in these consolidated financial statements:

At December 31, 2017:

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 and thereafter | Total |
|---|---|---|---|---|---|---|---|
| Distribution and Transmission segment projects[1] | $ 38 | $ 46 | $ 5 | $ - | $ - | $ - | $ 89 |
| Developer funded sanitary and stormwater capital projects[2] | 27 | 25 | 18 | - | - | - | 70 |
| Sanitary sewer rehabilitation and upgrade projects[3] | 10 | - | - | - | - | - | 10 |
| Other sanitary and stormwater projects[4] | 17 | - | - | - | - | - | 17 |
| Water Services power contracts[5] | 6 | 4 | 3 | 3 | - | - | 16 |
| Water purchase and transportation of water agreements[6] | 8 | 3 | 3 | 3 | 3 | 3 | 23 |
| Billing and customer care services agreement[7] | 4 | 3 | 3 | 3 | - | - | 13 |
| Information technology and communications service Agreements[8] | 2 | 1 | 1 | 1 | - | - | 5 |
| Operating leases payable[9] | 15 | 15 | 14 | 14 | 12 | 107 | 177 |
| | $ 127 | $ 97 | $ 47 | $ 24 | $ 15 | $ 110 | $ 420 |

At December 31, 2016:

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 and thereafter | Total |
|---|---|---|---|---|---|---|---|
| Distribution and Transmission segment projects[1] | $ 24 | $ 40 | $ 13 | $ 7 | $ 7 | $ - | $ 91 |
| Water Services segment projects | 13 | - | - | - | - | - | 13 |
| Water Services power contracts[5] | 9 | 6 | 3 | 3 | 3 | - | 24 |
| Water purchase and transportation of water agreements[6] | 9 | 2 | - | - | - | 4 | 15 |
| Billing and customer care services agreement[7] | 4 | 4 | 4 | 3 | 3 | - | 18 |
| Operating leases payable[9] | 15 | 15 | 14 | 13 | 12 | 119 | 188 |
| | $ 74 | $ 67 | $ 34 | $ 26 | $ 25 | $ 123 | $ 349 |

1 The Company has commitments for several Distribution and Transmission projects as directed by the AESO.

2 The Company has commitments for several developer funded new sanitary and stormwater infrastructure projects throughout the city of Edmonton.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

3 The Company has commitments to rehabilitate and upgrade the sanitary sewers in the West Jasper Palace area of the city of Edmonton.

4 The Company as a subcontractor has commitments to carry out construction of flood mitigation infrastructure within the city of Edmonton. These projects are funded by the City.

5 The Company has commitments to purchase power for its Edmonton water treatment plants and distribution sites, wastewater treatment plant and sanitary and stormwater collection sites. The agreements expire on or before December 31, 2021. Under the terms of the agreements, the Company is committed to purchase minimum contracted quantities at a fixed price. There are no early termination or cancellation clauses in these agreements.

6 Water Arizona maintains agreements with the Central Arizona Water Conservation District for the purchase and transportation of water. These agreements are for terms of 100 years expiring at the end of 2107. Under the terms of these agreements, the Company is committed for the amount of water ordered in the fall of each year to be purchased and transported the following year.

Water New Mexico maintains agreements with the various well owners for the purchase of water. These agreements are generally for terms of ten years. Under the terms of these agreements, certain minimum purchases are due each year in order to maintain the agreements until they expire.

7 The Company has entered into an agreement for billing and customer care services for U.S. Operations. The contract term is ten years, expiring on August 31, 2021.

8 The Company has commitments for several information technology and communication service agreements.

9 Represents the Company's gross future operating leases payable for its head office and other premises.

In 2007, the Company entered into a long-term agreement to lease commercial space in a new office tower in Edmonton, Canada, primarily for its head office (head office lease). The agreement, which became effective in the fourth quarter of 2011, has an initial lease term of approximately 20 years, expiring on December 31, 2031, and provides for three successive five-year renewal options.

Under the terms of the lease, the Company's annual lease commitments, net of annual payments to be paid to the Company by Capital Power and another company under the sub-leases receivable discussed below, are as follows:

| | Minimum lease payable |
|---|---|
| January 1, 2018 through December 31, 2022 | $ 6 |
| January 1, 2023 through December 31, 2023 | 7 |
| January 1, 2024 through December 31, 2031 | 8 |

The Company has sub-leased a portion of the space under its head office lease to Capital Power under the same terms and conditions as the Company's lease with its landlord.

Effective November 1, 2013, the Company also sub-leased a portion of the space under its head office lease to a third party. The term of the sub-lease to the third party expires on October 31, 2023 with two renewal options of four years each.

Approximate future payments to the Company under the sub-leases receivable are as follows:

| | Minimum lease receivable | |
|---|---|---|
| | 2017 | 2016 |
| Within one year | $ 5 | $ 5 |
| After one year but not more than five years | 21 | 20 |
| More than five years | 37 | 43 |
| | $ 63 | $ 68 |

**Contingencies**

The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

**Guarantees**

The Company in the normal course of business issues payment guarantees on behalf of its subsidiaries to meet the conditions of the agreements with third parties. At December 31, 2017, guarantees totaling $421 million (2016 – $429 million) have been issued to various third parties.

## 33. Segment disclosures

The Company operates in the following reportable business segments, which follow the organization, management and reporting structure within the Company.

**Water Services**

Water Services is primarily involved in the treatment, transmission and distribution and sale of water, the collection and conveyance of sanitary and stormwater and the treatment of wastewater within Edmonton and other communities in Western Canada. This segment's water and wastewater business includes the provision of design, build, finance, operating and maintenance services for municipal and industrial customers in Western Canada.

**Distribution and Transmission**

Distribution and Transmission is involved in the transmission and distribution of electricity within Edmonton. This segment also provides commercial services including the construction and maintenance of street lighting, traffic signal and light rail transit electrical infrastructure for the City and for other municipal and commercial customers in Alberta.

**Energy Services**

Energy Services is primarily involved in the provision of regulated tariff electricity service and default supply electricity services to residential, small commercial and agricultural customers in Alberta. This segment also provides competitive electricity and natural gas products under the Encor brand.

**U.S. Operations**

U.S. operations are primarily involved in the treatment, transmission and distribution, and sale of water, and the collection and treatment of wastewater within the Southwestern U.S. In addition, this segment also provides natural gas distribution and transmission services in Texas, U.S. All of the Company's operations conducted in the U.S. are included in this segment.

**Other**

Other includes all of the remaining business segments of the Company which do not meet the criteria of a reportable business segment. Other primarily includes Canadian natural gas distribution business, financing revenues on the long-term receivable from Capital Power and the cost of the Company's net unallocated corporate office expenses. This segment also held the available-for-sale investment in Capital Power.

As explained in detail in note 3(V), during the year the Company has reassessed its reportable business segments. As a result of reassessment of reportable business segments, the segment information for prior year has been revised to correspond with the new reportable business segments.

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| Year ended December 31, 2017 | Water Services | Distribution & Transmission | Energy Services | U.S. Operations | Other | Intersegment Elimination | Consolidated |
|---|---|---|---|---|---|---|---|
| External revenues and other income | $ 468 | $ 501 | $ 837 | $ 225 | $ 16 | $ - | $ 2,047 |
| Inter-segment revenue | - | 202 | 12 | - | - | (214) | - |
| Total revenues and other income | 468 | 703 | 849 | 225 | 16 | (214) | 2,047 |
| Energy purchases and system access fees | - | 250 | 746 | - | 1 | (193) | 804 |
| Other raw materials and operating charges | 81 | 48 | - | 44 | 2 | (5) | 170 |
| Staff costs and employee benefits expenses | 103 | 83 | 27 | 32 | 40 | (4) | 281 |
| Depreciation and amortization | 88 | 86 | 6 | 43 | 13 | - | 236 |
| Franchise fees and property taxes | 25 | 79 | - | 8 | - | - | 112 |
| Other administrative expenses | 27 | 16 | 26 | 14 | 17 | (12) | 88 |
| Operating expenses | 324 | 562 | 805 | 141 | 73 | (214) | 1,691 |
| Operating income (loss) before corporate charges | 144 | 141 | 44 | 84 | (57) | - | 356 |
| Corporate income (charges) | (24) | (25) | (10) | (6) | 65 | - | - |
| Operating income | 120 | 116 | 34 | 78 | 8 | - | 356 |
| Finance recoveries (expenses) | (66) | (57) | (3) | (40) | 51 | - | (115) |
| Fair value gain on available-for-sale investment in Capital Power reclassified from other comprehensive income | - | - | - | - | 1 | - | 1 |
| Income tax recovery | 4 | - | - | 2 | 8 | - | 14 |
| Net income | $ 58 | $ 59 | $ 31 | $ 40 | $ 68 | $ - | $ 256 |
| Capital additions | $ 210 | $ 241 | $ 4 | $ 101 | $ 10 | $ - | $ 566 |

(Tabular amounts in millions of Canadian dollars unless otherwise indicated)

| Year ended December 31, 2016 (revised) | Water Service | Distribution & Transmission | Energy Services | U.S. Operations | Other | Intersegment Elimination | Consolidated |
|---|---|---|---|---|---|---|---|
| External revenues and other income | $ 449 | $ 457 | $ 812 | $ 213 | $ 15 | $ - | $ 1,946 |
| Inter-segment revenue | - | 177 | 11 | - | - | (188) | - |
| Total revenues and other income | 449 | 634 | 823 | 213 | 15 | (188) | 1,946 |
| Energy purchases and system access fees | - | 182 | 707 | - | - | (167) | 722 |
| Other raw materials and operating charges | 111 | 46 | - | 40 | 2 | (8) | 191 |
| Staff costs and employee benefits expenses | 92 | 85 | 28 | 31 | 42 | (3) | 275 |
| Depreciation and amortization | 51 | 80 | 6 | 39 | 13 | - | 189 |
| Franchise fees and property taxes | 21 | 71 | - | 7 | - | - | 99 |
| Other administrative expenses | 22 | 19 | 27 | 16 | 17 | (10) | 91 |
| Operating expenses | 297 | 483 | 768 | 133 | 74 | (188) | 1,567 |
| Operating income (loss) before corporate charges | 152 | 151 | 55 | 80 | (59) | - | 379 |
| Corporate income (charges) | (23) | (29) | (10) | (7) | 69 | - | - |
| Operating income | 129 | 122 | 45 | 73 | 10 | - | 379 |
| Finance recoveries (expenses) | (59) | (51) | (3) | (36) | 37 | - | (112) |
| Fair value gain on available-for-sale investment in Capital Power reclassified from other comprehensive income on sale of portion of investment | - | - | - | - | 42 | - | 42 |
| Dividend income from available-for-sale investment in Capital Power | - | - | - | - | 9 | - | 9 |
| Income tax recovery (expense) | (2) | - | - | (14) | 7 | - | (9) |
| Net income | $ 68 | $ 71 | $ 42 | $ 23 | $ 105 | $ - | $ 309 |
| Capital additions | $ 132 | $ 281 | $ 4 | $ 74 | $ 11 | $ - | $ 502 |

The Company's assets and liabilities by lines of business at December 31, 2017 and 2016 are summarized as follows:

| December 31, 2017 | Water Services | Distribution & Transmission | Energy Services | U.S. Operations | Other | Intersegment Elimination | Consolidated |
|---|---|---|---|---|---|---|---|
| Total assets | $ 6,088 | $ 2,256 | $ 184 | $ 1,253 | $ 3,532 | $ (2,955) | $ 10,358 |
| Total liabilities | 4,685 | 1,514 | 168 | 1,034 | 2,386 | (2,955) | 6,832 |

| December 31, 2016 (revised) | Water Services | Distribution & Transmission | Energy Services | U.S. Operations | Other | Intersegment Elimination | Consolidated |
|---|---|---|---|---|---|---|---|
| Total assets | $ 2,328 | $ 2,080 | $ 163 | $ 1,198 | $ 3,276 | $ (2,884) | $ 6,161 |
| Total liabilities | 1,762 | 1,407 | 150 | 1,005 | 2,049 | (2,884) | 3,489 |

**Non-current assets**

| | 2017 | 2016 |
|---|---|---|
| Canada | $ 8,238 | $ 4,469 |
| U.S. | 1,213 | 1,156 |
| | $ 9,451 | $ 5,625 |

### 34. Comparative information

The comparative information relating to operating expenses and business segments has been revised and reclassified, where applicable, to conform to current year presentation.

## APPENDIX D:
## Accounting order approving the deferral account for the Sensus ICON meters

**Ontario Energy Board** **Commission de l'énergie de l'Ontario**

**EB-2012-0116**

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

**AND IN THE MATTER OF** an application by Collus PowerStream Corp. for an order approving just and reasonable rates and other charges, to be effective September 1, 2013.

**BEFORE:** Ellen Fry
Presiding Member

Marika Hare
Member

**DECISION AND PROCEDURAL ORDER NO. 3**
**October 10, 2013**

Collus PowerStream Corp. ("Collus PowerStream") filed a completed application with the Ontario Energy Board (the "Board") on May 24, 2013 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Collus PowerStream charges for electricity distribution, to be effective September 1, 2013.

On July 10, 2013, the Board issued Procedural Order No. 1 wherein it granted intervenor status and cost award eligibility to each of Energy Probe Research Foundation ("Energy Probe"), School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC") and set dates for further procedural steps.

A technical conference took place on September 3, 2013. A settlement conference was convened on September 11, 2013. Collus PowerStream, Energy Probe, SEC and VECC (collectively, the “Parties”) participated in the settlement conference. The Parties reached a complete settlement on all issues in the proceeding.

On September 30, 2013, Collus PowerStream filed a proposed Settlement Agreement. The Agreement contains detailed supporting material, including all relevant calculations showing the impact of the implementation of the Proposed Settlement Agreement on Collus PowerStream’s revenue requirement, the allocation of the resulting revenue requirement to the customer rate classes and the determination of the final rates, including bill impacts and a proposed Tariff of Rates and Charges. On October 1, 2013 the applicant filed a proposed Accounting Order to support the establishment of a deferral account that was agreed to by the parties.

## Findings

The Board has reviewed the proposed Settlement Agreement and accepts it as filed. The Settlement Agreement is attached as Appendix “A” to this Decision and Order.

The Board notes that the settlement of Issue 2.1 in relation to the premature retirement of the Sensus iCon F and G model smart meters includes the establishment of a deferral account to track the total Net Book Value of $512,469 for 4,631 affected units over the next three years. In the Settlement Agreement the parties request that the Board consider the disposition of the balance in the deferral account at a later date, either in a Collus PowerStream proceeding, or as part of a larger generic proceeding, should the Board determine that a generic proceeding is appropriate. The Board approves the establishment of a deferral account and will consider the mechanics of the account following a brief submission phase on Collus Powerstream’s proposed Accounting Order.

See page 40 of the settlement proposal

A rate order will be issued, following the Board’s consideration of the submissions on the proposed Accounting Order and the accounting treatment of the stranded assets.

## THE BOARD ORDERS THAT

1. Board staff and intervenors wishing to make a submission on the proposed Accounting Order shall file such submissions with the Board and deliver them to the parties by **October 11, 2013**.

2. If Collus PowerStream wishes to reply, it shall file its reply submissions with the Board by **October 18, 2013**.

All filings to the Board must quote file number **EB-2012-0116,** be made through the Board's web portal at, https://www.pes.ontarioenergyboard.ca/eservice// and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

**DATED** at Toronto, October 10, 2013

**ONTARIO ENERGY BOARD**

*Original signed by*

Kirsten Walli
Board Secretary

**Appendix A**

**To Decision and Procedural Order No. 3**

**Collus PowerStream Corp.**

**Settlement Agreement**

**Board File No: EB-2012-0116**

**DATED: October 10, 2013**

**EB-2012-0116**

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

**AND IN THE MATTER OF** an application by Collus PowerStream Corp. for an order approving just and reasonable rates and other charges for electricity distribution to be effective September 1, 2013.

# SETTLEMENT AGREEMENT

**FILED: SEPTEMBER 30, 2013**

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## INTRODUCTION

Collus PowerStream Corp. ("Collus PowerStream") carries on the business of distributing electricity within the Town of Collingwood, the former Towns of Thornbury and Stayner and the Village of Creemore as described in its distribution licence. Collus PowerStream filed an application with the Ontario Energy Board (the "Board") on April 30, 2013 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15 (Schedule B), seeking approval for changes to the rates that Collus PowerStream charges for electricity distribution, to be effective September 1, 2013 (the "Application"). The Board assigned the Application File Number EB-2012-0116. Following its receipt of correspondence from the Board, Collus PowerStream filed an updated/complete version of the Application on May 24, 2013.

Three parties requested and were granted intervenor status: Energy Probe Research Foundation ("Energy Probe" or "EP"), the School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC"). These parties are referred to collectively as the "Intervenors".

In Procedural Order No. 1, issued on July 10, 2013, the Board approved the Intervenors in this proceeding, set dates for interrogatories, interrogatory responses, a Technical Conference and a Settlement Conference, and made its determination regarding the cost eligibility of the Intervenors.

The evidence in this proceeding (referred to herein as the "Evidence") consists of the Application and Collus PowerStream's responses to interrogatories and Technical Conference questions, and its responses to Undertakings given during the Technical Conference. The Appendices to this Proposed Settlement Agreement (the "Agreement") are also included in the Evidence. The Settlement Conference was duly convened in accordance with the Procedural Order No. 1, with Ms. Tracey Ehl as facilitator. The Settlement Conference was held on September 11, 12 and 13, 2013.

Collus PowerStream and the following Intervenors participated in the Settlement Conference:

- Energy Probe ("EP");
- SEC; and
- VECC.

Collus PowerStream and the Intervenors are collectively referred to below as the "Parties".

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Board's *Settlement Conference Guidelines* (the "Guidelines"). The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counteroffers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Agreement.

The role adopted by Board Staff in the Settlement Conference is set out in page 5 of the Guidelines. Although Board staff is not a party to this Agreement, as noted in the Guidelines, Board staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

## A COMPLETE SETTLEMENT HAS BEEN REACHED ON ALL ISSUES IN THIS PROCEEDING

The Parties are writing to advise the Board that a complete settlement has been reached on all issues in this proceeding. This document comprises the Agreement and it is presented jointly by Collus PowerStream, Energy Probe, SEC, and VECC to the Board. It identifies the settled matters and contains such references to the Evidence as are necessary to assist the Board in understanding the Agreement. The Parties believe that the Evidence filed to date in respect of each settled issue, as supplemented in some instances by additional information recorded in this Agreement, supports the settlement of the matters identified in this Agreement. In addition, the Parties believe that the Evidence, supplemented where necessary by the additional information appended to this Agreement, contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached by the Parties.

The Parties explicitly request that the Board consider and accept this Agreement as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Agreement. The distinct issues addressed in this proposal are intricately interrelated and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Agreement in its entirety, then there is no Agreement unless the Parties agree that those portions of the Agreement the Board does accept may continue as a valid settlement.

It is further acknowledged and agreed that none of the Parties will withdraw from this Agreement under any circumstances, except as provided under Rule 32.05 of the *Board's Rules of Practice and Procedure*.

It is also agreed that this Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Agreement. However, none of the Parties will, in any subsequent proceeding, take the position that the resolution therein of any issue settled in this Agreement, if contrary to the terms of this Agreement, should be applicable for all or any part of the 2013 Test Year.

References to the Evidence supporting this Agreement on each issue are set out in each section of the Agreement. The Appendices to the Agreement have been added to the Evidence to provide further evidentiary support. The Parties agree this Agreement and the Appendices form part of the record in EB-2012-0116. The Appendices were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement. Appendix G to this Agreement – Proposed Schedule of 2013 Tariff of Rates and Charges (Updated) – is a proposed schedule of Rates and Charges. If the Board approves the Agreement, the Parties propose that the Board issue its Final Rate Order on the basis of this Appendix.

The Parties believe the Agreement represents a balanced proposal that protects the interests of Collus PowerStream's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow Collus PowerStream to manage its assets so that the highest standards of performance are achieved and customers' expectations for the safe and reliable delivery of electricity at reasonable prices are met. The Parties have agreed the effective date of the rates resulting from this proposed Agreement is October 1, 2013 (referred to below as the "Effective Date"). The Parties have also agreed to an implementation date of November 1, 2013, and a rate rider to refund/recover from ratepayers the difference in revenue collected from the effective date of October 1st through the anticipated implementation date of November 1st. In the event that it is not possible for the Board to issue its Rate Order in time for November 1st implementation, the Parties have agreed to a rate rider to refund/recover from ratepayers the difference in revenue collected from the effective date of October 1st through the actual implementation date as determined by the Board.

## ORGANIZATION AND SUMMARY OF THE SETTLEMENT AGREEMENT

As noted above, there is no Board-approved Issues List for this proceeding. For the purposes of organizing this Agreement, the Parties have used the Issues List in the Guelph Hydro Electric Systems Inc. proceeding (EB-2011-0123) as a guide, as that Issues List addresses all of the revenue requirement components, load forecast, deferral and variance account dispositions, cost allocation and rate design and other issues that are also relevant to determining Collus PowerStream’s 2013 distribution rates. The following Appendices accompany this Settlement Agreement:

A Summary of Significant Changes
B Fixed Asset Continuity Tables (2012 and 2013Updated)
C Cost of Power Calculation (Updated)
D 2013 Customer Load Forecast (Updated)
E 2013 Other Revenue (Updated
F 2013 PILS (Updated)
G Proposed 2013 Schedule of Rates and Charges (Updated)
H Rate Rider for Revenue Differences Effective Date vs. Implementation Date
I Updated Customer Impact – (Updated)
J Cost Allocation Sheet O1 (Updated
K Revenue Requirement Work Form (Updated)
L Throughput Revenue (Updated)
M Revenue Reconciliation / Validation (Updated)

## UNSETTLED MATTERS

There are no unsettled matters in this proceeding.

## OVERVIEW OF THE SETTLED MATTERS

This Agreement will allow Collus PowerStream to continue to make the necessary investments in maintenance and operation expenditures as well as capital investments to maintain the safety and reliability of the electricity distribution service that it provides.

This Agreement will also allow Collus PowerStream to: maintain current capital investment levels and, where required, appropriately increase capital investment levels in infrastructure to ensure a reliable distribution system; manage current and future staffing levels, skills and training to ensure regulatory compliance with Codes and Regulations; promote conservation programs including the Ministry of Energy directives as a condition of Collus PowerStream's distribution licence; and provide the high level of customer service that Collus PowerStream's customers expect.

The Parties agree no rate classes face bill impacts that require mitigation efforts as a result of this Agreement.

In this Agreement, except where otherwise expressly stated, all dollar figures are calculated and expressed using Canadian Generally Accepted Accounting Principles ("CGAAP"). For the purposes of settlement, the Parties acknowledge that Collus PowerStream is not converting to International Financial Reporting Standards ("IFRS") in the 2013 Test Year and intends to remain on CGAAP until required by the Accounting Standards Board (the "AcSB") to move to IFRS. However, Collus PowerStream complied with the Board's letter titled "Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies 2013" dated July 17, 2012. Collus PowerStream has implemented the regulatory accounting changes for depreciation expense and capitalization policies effective January 1, 2013.

In Collus PowerStream's initial evidence in Exhibit 6, Tab 1, Schedule 1, Page 6, the Service Revenue Requirement for the 2013 Test Year was $6,981,397 which included a Base Revenue Requirement of $6,515,797 and Revenue Offsets of $465,600 with a resulting Revenue Deficiency of $934,302. Through the interrogatory and settlement process, Collus PowerStream made changes to the Service Revenue Requirement as shown in the following table.

## Settlement Table #1: Service Revenue Requirement

| | | COS as Filed | Interrogatories & Undertakings | Settlement Submission | Difference Filing vs. Settlement |
|---|---|---|---|---|---|
| Service Revenue Requirement | A | $ 6,981,397 | $ 6,973,871 | $ 6,760,453 | $ (220,944) |
| Revenue Offsets | B | $ (465,600) | $ (480,405) | $ (480,405) | $ (14,805) |
| Base Revenue Requirement | C=A+B | $ 6,515,797 | $ 6,493,466 | $ 6,280,048 | $ (235,749) |
| Revenue at Existing Rates | D | $ 5,581,495 | $ 5,583,185 | $ 5,610,672 | $ 29,177 |
| Revenue Deficiency/(Sufficiency) | E=C-D | $ 934,302 | $ 910,280 | $ 669,376 | $ (264,926) |

The revised Service Revenue Requirement for the 2013 Test Year is $6,760,453 which reflects the updated cost of capital parameters (ROE and Deemed Short Term Debt rate) issued by the Board on February 14, 2013 applicable to applications for rebasing effective May 1, 2013. Compared to the forecast 2013 revenue at current rates of $5,610,672 the revised Service Revenue Requirement represents a revenue deficiency of $669,376.

Through the settlement process, Collus PowerStream has agreed to certain adjustments from its original 2013 Application and subsequent updated Evidence. Any such changes are described in the sections below.

## 1.0 GENERAL

### 1.1 Has Collus PowerStream responded appropriately to all relevant Board directions from previous proceedings?

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| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 9, Tab 1, Schedule 1, Page 13 of 29; Exhibit 1, Tab 1, Schedule 15 |
| | Interrogatories: 9.0-Staff-37, 9.0-Staff-37A (filed 20130917) |

**Directive from 2009 Cost of Service Application Review Motion (EB-2009-0130)**

Following Collus PowerStream's (formerly Collus Power's) last cost of service application, the Board ruled that account #2425 – Other Deferred Credits, Sub-Account Interest Rate Differential (VECC Appeal) be used to record an amount owing to customers as the result of a successful appeal by VECC in respect of the rate to be applicable to Collus Power's long term debt for rate making purposes. This amount including carrying charges was tracked and further details in this regard were provided in Exhibit 9, Tab 1, Schedule 1 of the Application. For the purposes of settlement, the Parties accept that Collus PowerStream has appropriately addressed the disposition of the balance, in the amount of $83,625, in its proposed Schedule of Rates and Charges at Appendix G.

**Directive from 2010 IRM Application (EB-2009-0220)**

In its Decision in Collus Power's 2010 IRM application, the Board ordered that account 1595 be used to record a tax sharing fund amount of $2,265 for disposition at a future proceeding. Collus PowerStream has done so and requested disposition in this proceeding.

The Board also directed that deferral account 1592 Sub-Account HST be used to track the incremental input tax credits ITC for revenue requirement items that were previously subject to PST and have become subject to HST. This has been done and Collus PowerStream requested that 50% of the account balance be disposed of in this Application. The Board also directed that Group 1 RSVA amounts be returned over a 4 year period. As this account disposition is still ongoing in 2012-13, it was not included in the current Application. The Board ruled that the loss of Collus Power's Large Use customer warranted an adjustment to the load profile established in the 2009 rebasing. The adjustment was made and Collus Power was to notify the Board immediately if the Subject Customer reverted to a large user during the final IRM period. The Subject Customer has not reverted to the large user customer class.

For the purposes of settlement, the Parties accept that Collus PowerStream has appropriately addressed the disposition of the balance of the tax sharing fund, in the amount of $2,265, in its proposed Schedule of Rates and Charges at Appendix G. The Parties accept, for the purposes of settlement, that Collus PowerStream has appropriately addressed the incremental ITC for revenue requirement items that were previously subject to PST and have become subject to HST. Additional details can be found in section 9.1.

### 1.2 Are Collus PowerStream's economic and business planning assumptions for 2013 appropriate?

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**Status:** **Complete Settlement**
Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC
Evidence: Application: Exhibit 1

For the purposes of settlement, the Parties accept Collus PowerStream's economic and business planning assumptions for 2013 as reasonable and appropriate for rate setting purposes.

### 1.3 Is service quality, based on the Board specified performance assumptions for 2013, appropriate?

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**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 6, Schedule 1

For the purposes of settlement, the Parties accept Collus PowerStream's evidence with respect to the acceptability of its service quality, based on the Board-specified indicators. The evidence shows that the service quality indicators meet or exceed the Board's minimum standards.

### 1.4 What is the appropriate effective date for any new rates flowing from this Application? If that effective date is prior to the date new rates are actually implemented, what adjustments should be implemented to reflect the sufficiency or deficiency during the period from effective date to implementation date?

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**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 1, Tab 2, Schedule 1

For the purpose of settlement, the Parties accept that the appropriate effective date of the new rates flowing from this Application is October 1, 2013. The implementation date is November 1, 2013, and the Parties have also agreed to a rate rider to recover from ratepayers the difference in revenue collected from the effective date of October 1$^{st}$ to the anticipated implementation date of November 1st. In the event that it is not possible for the Board to issue its Rate Order in time for November 1$^{st}$ implementation, the Parties have agreed to a rate rider to recover from ratepayers the difference in revenue collected from the effective date of October 1st through the actual implementation date as determined by the Board. The calculation of the rate rider is set out in Appendix H.

## 2.0 RATE BASE

### 2.1 Is the proposed rate base for the test year appropriate?

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| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 2 |
| | Interrogatories: 2.0-Staff-5 to 2.0-Staff-13, 9.0-Staff-32, 2-EP-8 to 2-EP-17, 2-SEC-3 to 2-SEC-7, 2.0-VECC-3 to 2.0-VECC-11, 2-EP-46s, 2-EP-47s |
| | Undertakings: JT1.8 |

For the purposes of settlement, the Parties have agreed that Collus PowerStream's amended forecast Rate Base of $19,642,855 for the 2013 Test Year under CGAAP is appropriate. A full calculation of this agreed Rate Base is set out in Settlement Table #2 below. The 2012 revised capital expenditures and amortization expense have been updated to reflect 2012 actuals and 2013 has been adjusted accordingly.

Capital additions for 2013 have been reduced by $50,000. Net fixed assets have been adjusted to remove the net book value of smart meters taken out of service up to 2012 and forecasted to be replaced in 2013. The revised fixed asset continuity schedules are in Appendix B. The amortization expense for 2013 has been adjusted to reflect the agreed upon capital expenditure adjustments for both 2012 and 2013.

The Parties note that the agreed upon Rate Base reflects, among other adjustments, the removal and replacement of certain smart meters – specifically, Sensus iCon F and iCon G model smart meters. These models were installed early in the Collus Power smart meter implementation process. They have since exhibited communication and memory failures, and they are not capable of encrypting data. The problems with these meters are discussed at page 29, section 8.3 of Collus PowerStream's Asset Management Plan (Exhibit 2, Tab 3, Schedule 2, Appendix A to the Application). Collus PowerStream has a three-year plan to replace these meters. That plan includes spending $166,250 on replacement smart meters in the 2013 Test Year, the first of the three years over which the replacements will take place.

Collus PowerStream has noted that it is anticipated that the issues related to these iCon F and G model smart meters will not be unique to them, but rather, may affect many distributors that installed these meters. Accordingly, for the purposes of settlement, the Parties have arrived at the following approach to the treatment of these meters:

- The Parties have agreed, for the purposes of settlement, that iCon F and G model smart meters removed from service in 2011 and 2012 will be removed from Rate Base and the stranded costs related to those meters (approximately $32,000) will not be recoverable.

- Collus PowerStream requests a new deferral account to track stranded asset cost. The Parties agreed to remove the net book value of iCon F and G model smart meters taken out of service in 2013 (approximately $184,000) from Rate Base and to track the stranded costs related to those meters in the new deferral accounts. The net book value of iCon F and G model smart meters removed from service after 2013 will also be tracked in the deferral account. It is proposed that the disposition of the balance in that deferral account be considered by the Board at a later date, either in a Collus PowerStream proceeding, or as part of a larger generic proceeding if and when the extent of the issue with these meter models among other Ontario electricity distributors is known. The deferral account is also discussed below in the context of Deferral and Variance Accounts (Issue 9.0)

- The replacement smart meters to be installed to replace the iCon F and G model smart meters in 2013 will be included in the 2013 Test Year Rate Base in the same manner as other 2013 Test Year capital additions. They will not be subject to the deferral account treatment to which the removed meters will be subject, nor will the recovery of costs related to those new smart meters be subject to a determination by the Board at a later date in the same way as is proposed herein for the removed meters. Similarly, replacement smart meters to be installed to replace the iCon F and G model smart meters in years following the 2013 Test Year will not be subject to the deferral account treatment to which the removed meters will be subject, nor will the recovery of costs related to those new smart meters be subject to determination by the Board at a later date in the same way as is proposed herein for the removed meters..

The revised Rate Base value reflects the changes to the working capital allowance described in Section 2.2.

The changes to the working capital allowance are set out in Settlement Table #3: Allowance for Working Capital, under Section 2.2 below.

Agreed upon adjustments to Collus PowerStream's proposed Overall Rate Base under CGAAP are set out in Settlement Table #2: Rate Base, below.

**Settlement Table #2: Rate Base**

| | | COS as Filed | Interrogatories & Undertakings | Settlement Submission | Difference Filing vs. Settlement |
|---|---|---|---|---|---|
| Average Gross Fixed Assets | A | $ 32,024,061 | $ 32,024,061 | $ 31,875,061 | $ (149,000) |
| Average Accumulated Depreciation | B | $ (16,324,684) | $ (16,324,684) | $ (16,319,234) | $ 5,450 |
| Average Net Fixed Assets | C=A+B | $ 15,699,377 | $ 15,699,377 | $ 15,555,827 | $ (143,550) |
| Allowance for Working Capital | D | $ 4,553,721 | $ 4,468,434 | $ 4,087,029 | $ (466,692) |
| Total Rate Base | E=C-D | $ 20,253,098 | $ 20,167,811 | $ 19,642,856 | $ (610,242) |

- The $149,000 reduction in the 2013 average gross fixed assets (GFA) is the result of the $32,000 reduction to the opening GFA and the $266,000 reduction to closing GFA which reduces the average GFA by $149,000, i.e., the average of the change in the opening and closing balances. The 2012 smart meters removed from service of $32,000 reduces both the opening and closing GFA. The reduction in capital additions for 2013 of $50,000 and the 2013 smart meters removed from service of $184,000 along with the $32,000 adjustment to the opening GFA make up the $266,000 reduction in closing GFA.

- The $5,450 reduction in the 2013 average accumulated depreciation (AD) is a result of the change in depreciation related to the capital adjustments noted in the preceding paragraph. Opening AD was reduced by $1,067, representing half year depreciation on the smart meters removed from fixed assets in 2012. Closing AD and depreciation expense for the 2013 Test Year was reduced by $8,767 representing full year depreciation on the meters replaced in 2012 and a half year depreciation on the reduced capital additions and smart meters removed from service in 2013.

- Changes in the allowance for working capital are discussed in section 2.2 below.

### 2.2 Is the working capital allowance for the test year appropriate?

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**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 1, Schedules 1 and 2, Exhibit 2, Tab 4, Schedule 1

Interrogatories: 2-EP-8, 2-EP-9, 2-EP-17, 2.0-VECC-11, 2-EP-46s

For the purposes of settlement, the Parties agree to the following Working Capital Allowance calculated based on 12% of the eligible controllable expenses of $4,441,160 and Cost of Power of $29,617,411. This reflects the following adjustments:

- Collus PowerStream's Cost of Power calculation was adjusted from the initial application amount of $30,273,460 to $29,617,410 as shown in Settlement Table #3a below.

- The 2013 OM&A for the Test Year should be $4,585,160, a decrease of $170,000 from $4,755,160 in the original Application. OM&A expenses are discussed in further detail under item 4.1. In addition, for the purposes of the calculation of the Working Capital Allowance only, the Parties have agreed to further reduce OM&A by $144,000 to reflect the removal of depreciation on transportation expenses from controllable expenses. The parties agree that for all other purposes, this amount of $144,000 is appropriately included in OM&A.

The Parties agree the adjustments shown in the table below, reflecting the settled matters as summarized elsewhere in this Agreement, will be made to Collus PowerStream's Working Capital Allowance calculation.

**Settlement Table #3: Allowance for Working Capital**

| | | COS as Filed | Interrogatories & Undertakings | Settlement Submission | Difference Filing vs. Settlement |
|---|---|---|---|---|---|
| Controllable Expenses | A | $ 4,755,160 | $ 4,755,160 | $ 4,441,160 | $ (314,000) |
| Cost of Power | B | $ 30,273,460 | $ 29,617,411 | $ 29,617,411 | $ (656,049) |
| Working Capital Base | C=A+B | $ 35,028,620 | $ 34,372,571 | $ 34,058,571 | $ (970,049) |
| Working Capital Rate | D | 13.0% | 13.0% | 12.0% | -1.0% |
| Working Capital Allowance | E=C*D | $ 4,553,721 | $ 4,468,434 | $ 4,087,029 | $ (466,692) |

**Settlement Table #3a: 2013 Cost of Power**

| Description | COS as Filed | Interrogatories & Undertakings | Settlement Submission | Difference Filing vs. Settlement |
|---|---|---|---|---|
| Commodity (Electricity) costs | $ 26,211,741 | $ 24,714,242 | $ 24,714,242 | $ (1,497,499) |
| Wholesale market costs | $ 1,704,319 | $ 1,704,319 | $ 1,704,319 | $ - |
| Transmission Network costs | $ 1,785,596 | $ 1,785,596 | $ 1,785,596 | $ - |
| Transmission Connection costs | $ 133,592 | $ 975,042 | $ 975,042 | $ 841,450 |
| Low Voltage costs | $ 438,212 | $ 438,212 | $ 438,212 | $ - |
| Total cost of power | $ 30,273,460 | $ 29,617,411 | $ 29,617,411 | $ (656,049) |

The revised cost of power forecast can be found in Appendix C. The cost of electricity was updated to the latest forecast price. Transmission Connection costs were misstated due to a clerical error and have been corrected to be consistent with costs used to determine retail transmission service rates.

### 2.3 Is the capital expenditure forecast for the test year appropriate?

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**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 3, Schedules 1 to 10

Interrogatories: 2.0-Staff-7 to 2.0-Staff-13, 2-EP-10, 2-EP-11, 2-EP-15, 2-EP-16, 2-SEC-3 to 2-SEC-9, 2.0-VECC-3 to 2.0-VECC-9

Undertakings: JT1.8

For the purposes of settlement, the Parties accept net capital expenditures of $1,973,208 amended from Collus PowerStream's original application of $2,023,208. This reflects a reduction of $50,000 in planned capital expenditures for the 2013 Test Year. The Parties agreed that this amount of capital work could be deferred in 2013 without serious adverse effect on Collus PowerStream's distribution system. The resulting continuity schedule is shown in Appendix B.

### 2.4 Is the capitalization policy and allocation procedure appropriate?

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**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Exhibit 2, Tab 3, Schedule 9

For the purposes of settlement, the Parties accept Collus PowerStream's capitalization policy as set out in Exhibit 2, Tab 3, Schedule 9 of the original Application, is consistent with Board guidance**,** including the Board's letter of July 17, 2012, *Regulatory accounting policy direction regarding changes to depreciation and capitalization polices in 2012 and 2013.* For 2013 Collus PowerStream has made the required change to its capitalization policies to be "IFRS-compliant".

## 3.0 LOAD FORECAST AND OPERATING REVENUE

### 3.1 Is the load forecast methodology including weather normalization appropriate?

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| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 3, Tab 1, Schedules 1 to 4 |
| | Interrogatories: 3.0-Staff-14 to 3.0-Staff-18, 3-EP-19, 3-EP-20, 3-SEC-8, 3.0-VECC-12 to 3.0-VECC-20, 3-EP-48s to 50s, 3.0-VECC TCQ-44 to 48 |
| | Undertakings: JT1.1, JT1.15, JT1.16 |

For the purposes of settlement, the Parties accept Collus PowerStream's load forecast methodology, including weather normalization, as modified through the interrogatory process. As a result of the adjustments to the proposed customers/connections and load forecasts discussed below, the 2013 Test Year gross kWh load forecast, net of CDM, is 304,264,561 kWh, inclusive of losses. The resulting billed consumption forecast for the 2013 Test Year is summarized in Settlement Table #4 found in section 3.2 below. The accepted CDM adjustment for 2013 is 9,473,440 kWh for the 2013 Test Year.

### 3.2 Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 3, Tab 1, Schedules 1 to 4 |
| | Interrogatories: 3.0-Staff-14 to 3.0-Staff-18, 3-EP-19, 3-EP-20, 3-SEC-8, 3.0-VECC-12 to 3.0-VECC-20, 3-EP-48s to 50s, 3.0-VECC TCQ-44 to 48 |
| | Undertakings: JT1.1, JT1.15, JT1.16 |

For the purposes of settlement, the Parties agree to make the following adjustments to Collus PowerStream's customers/connections forecast and to its load forecasts (both kWh and kW) for the 2013 Test Year following the adjustment set out under Issue 3.3 below:

- Load forecast model was updated to account for a half-year rule for 2011-2014 CDM targets allocation, while all other model input variables remained unchanged as per filed evidence from April 30, 2013. The customer count for the Residential class reverts to the original forecast as per the prefiled evidence in Exhibit 3, Tab 1, Schedule 4. This ensures consistency across model outputs, as the residential customer count is one of the drivers of the load forecast model. It was agreed that model inputs should be unchanged from the load forecast as filed with the exception of correcting the CDM reductions.

- Increase the billed kW forecast for the GS>50 kW class to 342,409 kWs based on 2012 actual, after adjustment to remove a bankrupt customer, and growth of 0%.

- Increase the billed kW forecast for the Street Lighting class to 6,285 kW based on 2012 actual and growth of 0.5%.

The various adjustments described above are set out below in Settlement Table #4.

# Settlement Table #4: Load Forecast

| Rate Class | COS As Filed | Adjustments | Settlement Submission |
|---|---|---|---|
| **Residential** | | | |
| Customers | 14,233 | 0 | 14,233 |
| kWh | 117,986,753 | (30,164) | 117,956,589 |
| | | | |
| **General Service < 50 kW** | | | |
| Customers | 1,717 | 0 | 1,717 |
| kWh | 47,186,130 | (12,265) | 47,173,865 |
| | | | |
| **General Service > 50 kW** | | | |
| Customers | 114 | 3 | 117 |
| kWh | 116,434,672 | (29,862) | 116,404,810 |
| kW | 337,058 | 5,351 | 342,409 |
| | | | |
| **Street Light** | | | |
| Connections | 3,045 | 0 | 3,045 |
| kWh | 2,166,298 | (561) | 2,165,737 |
| kW | 6,228 | 57 | 6,285 |
| | | | |
| **Unmetered Scattered Load** | | | |
| Connections | 30 | 0 | 30 |
| kWh | 403,608 | (104) | 403,504 |
| | | | |
| **Total** | | | |
| **Customers/Connections** | **19,139** | **3** | **19,142** |
| **kWh** | **284,177,461** | **(72,956)** | **284,104,505** |
| **kW from applicable classes** | **343,286** | **5,408** | **348,694** |

## 3.3 Is the impact of CDM appropriately reflected in the load forecast?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 3, Tab 1, Schedules 1 to 4

Interrogatories: 3.0-Staff-14 to 3.0-Staff-18, 3-EP-19, 3-SEC-8, 3.0-VECC-12, 3.0-VECC-13, 3.0-VECC-19

TCQ: 3.0-VECC TCQ -46 to 48

Undertakings: JT1.16

For the purposes of settlement, the Parties agree that the 2013 CDM adjustment of 8,853,682 kWh (9,473,440 kWh before removal of losses) outlined in response to Undertaking JT 1.16 is appropriate. Using this CDM adjustment, the load forecast was revised as outlined in 3.2. The agreed-upon CDM-related adjustments to Collus PowerStream's load forecast are set out in Settlement Table #5a, below.

**Settlement Table #5a: CDM Adjusted Forecast**

| Rate Class | Billed Load Forecast before CDM Adjustment (kWh) | Billed Load Forecast after CDM Adjustment (kWh) | CDM Adjustment (kWh) |
|---|---|---|---|
| Residential | 121,632,526 | 117,956,589 | (3,675,937) |
| General Service < 50 kW | 48,643,966 | 47,173,865 | (1,470,101) |
| General Service > 50 kW | 120,032,388 | 116,404,810 | (3,627,578) |
| Street Lighting | 2,233,229 | 2,165,737 | (67,492) |
| Unmetered Scattered Loads | 416,079 | 403,504 | (12,575) |
| Totals | **292,958,188** | **284,104,506** | **(8,853,682)** |

| Rate Class | Billed Load Forecast before CDM Adjustment (kW) | Billed Load Forecast after CDM Adjustment (kW) | CDM Adjustment (kW) |
|---|---|---|---|
| Residential | | | 0 |
| General Service < 50 kW | | | 0 |
| General Service > 50 kW | 353,080 | 342,409 | (10,671) |
| Street Lighting | 6,481 | 6,285 | (196) |
| Unmetered Scattered Loads | | | 0 |
| Totals | **359,561** | **348,694** | **(10,867)** |

The CDM adjustment to the 2013 Load Forecast, gross and net of losses, is shown in Settlement Table #5b below.

**Settlement Table #5b: CDM Adjustment to 2013 load Forecast**

| Year | OPA Programs | 3rd Tranche | Revised CDM Targets 2011-2014 | Total CDM Savings | Loss Factor | Loss Factor, kWh Gross-up | CDM Savings, kWh (gross) |
|---|---|---|---|---|---|---|---|
| 2005 | | 158,967 | 0 | 158,967 | 8.8% | 14,037 | 173,004 |
| 2006 | 1,031,866 | 1,236,756 | 0 | 2,268,622 | 8.4% | 190,111 | 2,458,733 |
| 2007 | 2,580,762 | 436,092 | 0 | 3,016,854 | 8.4% | 252,812 | 3,269,666 |
| 2008 | 3,577,935 | 220,405 | 0 | 3,798,340 | 8.4% | 318,301 | 4,116,641 |
| 2009 | 5,621,541 | 0 | 0 | 5,621,541 | 7.5% | 421,616 | 6,043,157 |
| 2010 | 6,099,488 | 0 | 0 | 6,099,488 | 7.5% | 457,462 | 6,556,950 |
| 2011 | 5,698,064 | 0 | 410,187 | 6,108,251 | 7.5% | 458,119 | 6,566,369 |
| 2012 | 5,615,213 | 0 | 1,301,450 | 6,916,663 | 7.5% | 518,750 | 7,435,412 |
| 2013 | 5,589,642 | 0 | 3,264,040 | 8,853,682 | 7.0% | 619,758 | 9,473,440 |

Please note that the above CDM savings include the persistence savings from the older OPA programs. The OPA program amounts are from the OPA final reports and will not change. For purposes of the LRAMVA calculation, it is the CDM Targets for 2011-2014 savings of 3,264,040 kWhs that need to be compared with the actual CDM savings achieved from these programs. The reduction to the billing determinants that results from the 3,264,040 kWh of CDM savings is shown in Settlement Table #5c below.

**Settlement Table #5c: 2011 to 2014 CDM Savings Impact on Billing Determinants**

| Rate Class | Consumption kWh | Demand kW |
|---|---|---|
| Residential | 1,345,003 | |
| GS<50 | 543,085 | |
| Unmetered Scattered Load | 4,684 | |
| GS>50 | 1,346,579 | 10,671 |
| Street Lighting | 24,666 | 196 |
| **Total** | **3,264,018** | **10,867** |

### 3.4 Is the proposed forecast of test year throughput revenue appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 3, Tab 1, Schedules 1 to 4 |
| | Interrogatories: 3.0-Staff-14 to 3.0-Staff-18, 3-EP-19, 3-EP-20, 3-SEC-8, 3.0-VECC-12 to 3.0-VECC-20, 3-EP-48s to 50s, 3.0-VECC TCQ-44 to 48 |
| | Undertakings: JT1.1, JT1.15, JT1.16 |

For the purposes of settlement, the Parties agree on the throughput revenue of $5,610,672 as set out in Appendix L: Throughput Revenue.

### 3.5 Is the test year forecast of other revenues appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 3, Tab 3, Schedule 1, Page 2 of 3 |
| | Interrogatories: 3.0-EP-22 g), 3.0-EP-22 h), 3.0-VECC-21 |
| | TCQ: 3.0-VECC TCQ-50 a), 3.0-VECC TCQ-50 b) |
| | Undertaking: JT1.6-2 |

For the purposes of settlement, the Parties agree upon a forecast of $481,905 for Other Distribution Revenue; see Appendix E. This total includes $1,500 of non-utility revenue; the distribution revenue offsets are $480,405. This amount reflects the changes noted in undertaking JT1.6-2, a net increase of $14,805 as shown in the table below.

## Table JT1.6-2: Changes in Revenue Offsets

| Description | Increase (decrease) | Reference |
|---|---|---|
| Miscellaneous service revenues | $ (40,000) | 3.0-VECC TCQ-50 b |
| SSS Admin charge | $ 48,000 | 3.0-VECC TCQ-50 a |
| Gain on disposal | $ 4,600 | 3-EP-22 g |
| MicroFIT revenues | $ 2,205 | 3-EP-22 h |
| **Total** | **$ 14,805** | |

## 4.0 OPERATING COSTS

### 4.1 Is the overall OM&A forecast for the test year appropriate?

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| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 4 |
| | Interrogatories: 4.0-Staff-20 to 25, 4-EP-23 to 31, 4-EP-34, 4-SEC-10 to 17, 4.0-VECC-22 to 32 |
| | TCQ: 4-EP-52s to 54s |
| | Undertaking: JT1.2, JT1.9, JT1.10, JT1.11 |

For the purposes of settlement, the Parties agree the OM&A for the 2013 Test Year should be $4,513,160 (CGAAP) or $4,585,160 (MCGAAP), a decrease of $170,000 to the OM&A from the original value of $4,683,160 (CGAAP) or $4,755,160 (MCGAAP) in the Application. The Parties rely on Collus PowerStream's view that it can safely and reliably operate the distribution system based on the total OM&A budget proposed.

Collus PowerStream has provided on a preliminary basis, in Settlement Table #5: OM&A Expense Budget, below, a revised OM&A budget. The breakdown of the budget into categories is not intended by the Parties to be in any way a deviation from the normal rule that, once the budget is established, it is up to management to determine through the year how best to spend that budget given the actual circumstances and priorities of the company throughout the Test Year, and the Parties acknowledge that there may be variances between actual OM&A spending in the general categories in Settlement Table #5 and the preliminary amounts shown therein.

**Settlement Table #5: OM&A Expense Budget**

| | COS As Filed | Interrogatories | Settlement Submission | Difference Filing vs Settlement |
|---|---|---|---|---|
| Operations | $ 607,100.00 | $ 607,100.00 | $ 582,100.00 | $ (25,000.00) |
| Maintenance | $ 1,565,900.00 | $ 1,565,900.00 | $ 1,490,900.00 | $ (75,000.00) |
| Billing & Collecting | $ 1,013,862.00 | $ 1,013,862.00 | $ 993,862.00 | $ (20,000.00) |
| Community Relations | $ 138,000.00 | $ 138,000.00 | $ 138,000.00 | $ - |
| Administrative & General | $ 1,430,298.00 | $ 1,430,298.00 | $ 1,380,298.00 | $ (50,000.00) |
| Total (MCGAAP) | $ 4,755,160.00 | $ 4,755,160.00 | $ 4,585,160.00 | $ (170,000.00) |
| IFRS impact | $ (72,000.00) | $ (72,000.00) | $ (72,000.00) | |
| Total (CGAAP) | $ 4,683,160.00 | $ 4,683,160.00 | $ 4,513,160.00 | |

### 4.2 Is the proposed level of depreciation/amortization expense for the test year appropriate?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe (EP), SEC, VECC

Evidence: Application: Exhibit 2, Tab 3, Schedule 10; Exhibit 4, Tab 4, Schedule 7; Exhibit 10, Appendix 2-C

Interrogatories: 4-EP-32, 4-SEC-18

For the purposes of settlement, the Parties accept the useful lives and the depreciation expense reported in the continuity schedules in Appendix B. As cited in the Application, Collus PowerStream adopted revised depreciation rates under CGAAP as detailed in Exhibit 4, Tab 4, Schedule 7. Collus PowerStream is implementing this depreciation approach effective from January 1, 2013 and has applied it to the Test Year in its Evidence.

As cited in Collus PowerStream's Application, the Applicant adopted the half-year rule for depreciation. Collus PowerStream implemented this depreciation approach effective from January 1, 2013 and has applied it to the 2013 Test Year in its evidence. Going forward this approach is consistent with the Board's policies concerning treatment of depreciation.

### 4.3 Are the 2013 compensation costs and employee levels appropriate?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: E4/T4/S5 Page 3 Table 1, Appendix 2-K
Interrogatories: 4.0-VECC-32, 4.0-STAFF-25, 4.0-EP-31
TCQ: 2-VECC TCQ-43
Undertaking: JT1.2

For the purpose of settlement, the Parties accept that Collus PowerStream's forecasted 2013 Test Year compensation costs and employee levels are reasonable based on the Evidence provided on compensation policies, customer growth and additional work requirements. The forecasted 2013 Test Year compensation costs and employee levels may be affected by the overall reduction in 2013 Test Year OM&A discussed above in Section 4.1.

### 4.4 Is the test year forecast of property taxes appropriate?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 4, Tab 6, Schedule 1. Page 4 of 6, Table 2 (part 1)

For the purpose of settlement, the Parties accept Collus PowerStream's forecasted 2013 Test Year property taxes of $17,221.

### 4.5 Is the test year forecast of PILs appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 4, Tab 4, Schedule 8 |
| | Interrogatories: 4.0-Staff-26, 4-EP-33 |

For the purpose of settlement, the parties accept Collus PowerStream's 2013 Test Year PILs forecast of $67,958 as set out in Appendix F to this Settlement Agreement. Please see Appendix F – 2013 PILs (Updated), for additional details. The changes result from other adjustments throughout this Agreement.

## 5.0 CAPITAL STRUCTURE AND COST OF CAPITAL

### 5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 5

Interrogatories: 5-EP-35, 5-EP-36, 5-SEC-19, 5-SEC-20, 5.0-VECC-34

For the purposes of settlement, the Parties agree that Collus PowerStream's proposed capital structure of 56% long term debt, 4% short term debt, and 40% equity is appropriate. The Parties also agree that the short term debt rate and ROE, at rates of 2.07% and 8.98% respectively, which reflect the Board's deemed short term debt rate and ROE applicable to cost of service applications for rates effective May 1, 2013, are appropriate.

### 5.2 Is the proposed long term debt rate appropriate?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 5

Interrogatories: 5-EP-35, 5-EP-36, 5-SEC-19, 5-SEC-20, 5.0-VECC-34

For the purposes of settlement, the Parties accept Collus PowerStream's long term debt rate of 4.05%, as set out in Exhibit 5, Tab 1, Schedule 1, Table 2.

## 6.0 STRANDED METERS

### 6.1 Is the proposal related to Stranded Meters appropriate?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 9, Tab 1, Schedule 1, Table 11
Interrogatories: 9.0-Staff-33(d) & (e), 8.0-VECC-40
Undertaking: JT1.14, Table 9-11

For the purposes of settlement, the Parties agree that Collus PowerStream has appropriately calculated the Stranded Meter net book value as $469,325, as set out in Table 9-11 provided by Collus PowerStream in response to Technical Conference Undertaking JT1.14. The Parties further agree on the allocation methodology utilized to calculate the Stranded Meter Rate Rider to be collected over a 2 year period for Residential and GS<50 kW customers. As the implementation date for rates is November 1, 2013 the period of recovery has been revised to 18 months. Collus PowerStream utilized the 2006 Cost Allocation Filing sheet 17.1 to determine the allocation to the Residential and GS< 50 kW rate classes.

The proposed stranded meter rate riders are reflected in the following table.

**Settlement Table #6: Stranded Meter Rate Rider**

| Net Book Value Segregated by Rate Class: | Residential | GS <50 kW | Total |
|---|---|---|---|
| | $ 361,381 | $ 107,945 | **$ 469,325** |
| **Allocated Weighting Based on 2006 Cost Allocation Filling sheet 17.1** | 77% | 23% | **100%** |
| **Number of Metered Customers based on approved 2012 Smart Meter filing** | 14,406 | 1,867 | **16,273** |
| **Rate Rider to Recover Stranded Meter Costs:** | **1.39** | **3.21** | |
| **Recovery period (months):** | **18** | **18** | |

# 7.0 COST ALLOCATION

## 7.1 Is Collus PowerStream's cost allocation appropriate?

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**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 7
Interrogatories: 7.0-Staff-27 to 28, 7.0-VECC-35 to 36
Technical Questions: 7.0-VECC TCQ -51 to 53

For the purposes of settlement, the Parties agree that revenue-to-cost ratios for the 2013 Test Year, reflecting the agreed-upon 2013 Test Year Revenue Requirement, will be as set out in the following table, which is consistent with the Collus PowerStream Application.

**Settlement Table #7: 2013 Test Year Revenue to Cost Ratios**

| | Status Quo | | Proposed | |
|---|---|---|---|---|
| Class | Cost-Rev Ratio % | Revenue Allocation | Cost-Rev Ratio % | Revenue Allocation |
| Residential | 101.9 | $ 3,964,991 | 101.9 | $ 3,964,991 |
| GS < 50 kW | 93.0 | $ 1,011,359 | 94.1 | $ 1,025,094 |
| GS > 50 kW | 95.9 | $ 1,068,761 | 95.9 | $ 1,068,761 |
| Street Lighting | 125.4 | $ 226,943 | 120.0 | $ 216,481 |
| Unmetered | 198.3 | $ 7,994 | 120.0 | $ 4,721 |
| Total | | $ 6,280,048 | | $ 6,280,048 |

The Board's Cost Allocation Sheet O1 has been enclosed in Appendix J.

### 7.2 Are the proposed revenue-to-cost ratios for each class appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 7 |
| | Interrogatories: 7.0-Staff-27 to 28, 7.0-VECC-35 to 36 |
| | Technical Questions: 7.0-VECC TCQ -51 to 53 |

For the purposes of settlement, the Parties accept the revenue-to-cost ratios for the 2013 Test Year, as set out under issue 7.1, above, and agree that no further adjustments will be required from 2014-2016 as part of this Agreement. The Parties acknowledge that Collus PowerStream's revenue-to-cost ratios remain subject to further Board policy changes of general application over this period.

## 8.0 RATE DESIGN

### 8.1 Are the fixed-variable splits for each class appropriate?

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**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 8, Tab 1, Schedule 2

Interrogatories: 8.0-Staff-29, 8.0-Staff-30, 8-EP-37, 8.0-VECC-37, 8.0-VECC-40

TCQs: 8.0-VECC TCQ-54

Undertakings: JT1.3

For the purposes of settlement, the Parties agree to the proposed fixed-variable splits for each class presented in the table below.

**Settlement Table #8: Fixed –Variable Splits**

| Class | Variable | Fixed | Total | Variable | Fixed | Total |
|---|---|---|---|---|---|---|
| Residential | $ 2,277,586 | $ 1,687,405 | $ 3,964,991 | 57.4% | 42.6% | 100.0% |
| GS<50 | $ 618,332 | $ 406,762 | $ 1,025,094 | 60.3% | 39.7% | 100.0% |
| GS>50 | $ 934,285 | $ 134,475 | $ 1,068,761 | 87.4% | 12.6% | 100.0% |
| USL | $ 4,555 | $ 166 | $ 4,721 | 96.5% | 3.5% | 100.0% |
| Street Lighting | $ 90,425 | $ 126,056 | $ 216,481 | 41.8% | 58.2% | 100.0% |
| Total | $ 3,925,184 | $ 2,354,864 | $ 6,280,048 | 62.5% | 37.5% | 100.0% |

- Revenue was allocated to the rate classes based on the 2013 forecast billing determinants and current approved rates. The resulting class percentage of overall revenue and the current fixed variable splits were used to allocate the 2013 base revenue requirement to the rate classes and the initial split between fixed and variable. The resulting fixed monthly charge was compared to the Cost Allocation study “ceiling”. The adjustments below were made to the fixed monthly charge and the fixed and variable revenue portions were recalculated to match the total revenue allocation for the class. The final result is shown in Settlement Table #8 above.

- For the Residential, GS < 50 kW and Street Lighting classes the initial fixed/variable splits are used to define the fixed portion of the revenue assigned to the class and the resulting monthly fixed charge.

- The monthly fixed charge for the Unmetered Scattered Load class will be increased to the "floor" value as set out in the Cost Allocation Model of $0.46.

  For the GS > 50 kW class the monthly fixed charge will be $94.34. This is the halfway point between the current monthly fixed charge of $114.02 and the Minimum System with PLCC Adjustment (i.e. the "ceiling" from Cost Allocation model) value of $74.65.

### 8.2 Are the proposed retail transmission service rates ("RTSR") appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 8, Tab 1, Schedule 1 |
| | Interrogatories: 8.0-Staff-31 |

For the purposes of settlement the Parties agree the Retail Transmission Service Rates ("RTSRs"), based on the updated Uniform Transmission Rates issued by the Board on December 20, 2012 in EB-2012- 0031, are appropriate, and are as set out in the following table.

**Settlement Table #9: RTSR Network and RTSR Connection Rates**

| Rate Class | Unit | Proposed RTSR Network | | Proposed RTSR Connection | |
|---|---|---|---|---|---|
| Residential | kWh | $ | 0.0067 | $ | 0.0037 |
| General Service < 50 kW | kWh | $ | 0.0062 | $ | 0.0031 |
| General Service > 50 kW | kW | $ | 2.4666 | $ | 1.2764 |
| Street Lighting | kW | $ | 1.8602 | $ | 0.9867 |
| Unmetered Scattered Loads | kWh | $ | 0.0062 | $ | 0.0031 |

## 8.3 Are the proposed loss factors appropriate?

---

**Status:** **Complete Settlement**

Supporting Parties: Collus PowerStream, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 8, Tab1, Schedule 8

Interrogatories: 3.0-VECC-13 (c)

For the purposes of settlement, the Parties accept the proposed loss factors set out in Collus PowerStream's Application at Exhibit 8, Tab 1, Schedule 8.

When the Supply Facility Loss Factor of 1.034 is applied to the Distribution Loss Factor of 1.03574, the resulting Total Loss Factor for secondary metered customers is 1.0710.

## 9.0 DEFERRAL AND VARIANCE ACCOUNTS

### 9.1 Are the account balances, cost allocation methodology and disposition period appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 9, Tab 1, Schedule 1Interrogatories: 2.0-Staff-9, 2.0-Staff-10, 2.0-Staff-11, 2.0-Staff-12, 9.0-Staff-32, 9.0-Staff-33, 9.0-Staff-34, 9.0-Staff-35, 9.0-Staff-36, 9.0-Staff-37, 9-Energy Probe-39, 9-Energy Probe-40, 9-Energy Probe-41 |
| | TCQ: 9-Energy Probe-55s |

For the purposes of settlement, the Parties agree the account balances, cost allocation methodology and disposition period for the deferral and variance accounts as presented in the evidence cited above, adjusted for the matters discussed below, are appropriate.

For the purposes of settlement, the Parties agree to defer the recovery of Deferred IFRS transition costs, in the amount of $117,245 including interest, until Collus PowerStream transitions from Modified CGAAP to IFRS.

For the purposes of settlement, the Parties agree that the balance in account 1532 Renewable Generation Connection OM&A of $55,818 including interest, which relates to wages in conjunction with the MicroFIT settlement process, will be removed and expensed. Some of the Parties considered these particular wages to be non-incremental and deemed the wages to be covered by current rates. Collus PowerStream has agreed to remove them for the purposes of settlement.

For the purposes of settlement, the Parties agree that 50% of the balance including interest in account 1592 PILs and Tax Variance – HST/OVAT in the amount of $56,411 credit is being requested for disposition.

Settlement Table #10: Deferral and Variance Accounts, below summarizes the Parties' agreement with respect to the disposal of the balances of the accounts, including the updates that have occurred to the deferral and variance accounts for which disposal is sought in 2013.

## Settlement Table #10: Deferral and Variance Accounts

**Summary of Total Claim**

| | USof A | Closing Principal | Closing Interest | Projected Interest | Projected Interest | Total Claim |
|---|---|---|---|---|---|---|
| Total Group 1 Account Balance | | 277,635 | (27,285) | 4,115 | 2,743 | 257,208 |
| Total Group 2 Account Balance | | 596 | 10,110 | (1,872) | 6 | 8,839 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | (55,170) | (241) | (475) | (525) | (56,411) |
| **Total Claim** | | **223,061** | **(17,416)** | **1,767** | **2,224** | **209,637** |

**Summary of Group 1 Balances**

| Group 1 Accounts | USofA | Closing Principal | Closing Interest | Projected Interest | Projected Interest | Total Claim |
|---|---|---|---|---|---|---|
| LV Variance Account | 1550 | 165,144 | 643 | 2,428 | 1,618 | 169,833 |
| RSVA - Wholesale Market Service Charge | 1580 | (477,597) | (1,015) | (7,021) | (4,680) | (490,313) |
| RSVA - Retail Transmission Network Charge | 1584 | (1,153) | (1,375) | (17) | (11) | (2,556) |
| RSVA - Retail Transmission Connection Charge | 1586 | (24,817) | (1,050) | (365) | (243) | (26,474) |
| RSVA - Power (excluding Global Adjustment) | 1588 | 138,155 | (28) | 2,031 | 1,354 | 141,511 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | 559,826 | 748 | 8,229 | 5,486 | 574,290 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | (79,658) | (25,208) | (1,171) | (781) | (106,818) |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | (2,265) | - | - | - | (2,265) |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | **277,635** | **(27,285)** | **4,115** | **2,743** | **257,208** |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | **(282,191)** | **(28,033)** | **(4,115)** | **(2,743)** | **(317,082)** |

**Summary of Group 2 Balances**

| Group 2 Accounts | USofA | Closing Principal | Closing Interest | Projected Interest | Projected Interest | Total Claim |
|---|---|---|---|---|---|---|
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | 50,350 | 9,297 | 740 | 493 | 60,881 |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charge: | 1508 | 11,112 | 251 | 163 | 109 | 11,635 |
| Smart Grid Capital Deferral Account | 1534 | 6,668 | 311 | 98 | 65 | 7,142 |
| Smart Grid OM&A Deferral Account | 1535 | 12,256 | 252 | 180 | 120 | 12,808 |
| Other Deferred Credits | 2425 | (79,790) | | (3,054) | (782) | (83,625) |
| **Group 2 Sub-Total** | | **596** | **10,110** | **(1,872)** | **6** | **8,839** |
| *PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | (55,170) | (241) | (475) | (525) | (56,411) |

*Account 1592 disposition has been calculated for Principal and interest up September 30, 2013.

As discussed in the context of Issue 2.1 above, the Parties propose that net book value of iCon F and G model smart meters removed from service in 2013 (approximately $184,000) will be removed from Rate Base and the stranded costs related to those meters will be tracked in a new deferral account to be assigned by the Board. The net book value of iCon F and G model smart meters removed from service after 2013 (in Collus PowerStream's case, all iCon F and G model smart meters would be removed in 2013, 2014 and 2015) will also be tracked in the deferral account. It is proposed that the disposition of the balance in that deferral account will be considered by the Board at a later date, either in a Collus PowerStream proceeding or as part of a larger generic proceeding if and when the extent of the issue with these meter models among other Ontario electricity distributors is known. The Parties respectfully request that the Board confirm the establishment of the proposed deferral account in its Order approving this Settlement Agreement.

### 9.2 Are the proposed rate riders to dispose of the account balances appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 9, Tab 1, Schedule 1 |
| | Interrogatories: 2.0-Staff-9, 2.0-Staff-10, 2.0-Staff-11, 2.0-Staff-12, 9.0-Staff-32, 9.0-Staff-33, 9.0-Staff-34, 9.0-Staff-35, 9.0-Staff-36, 9.0-Staff-37, 9-Energy Probe-39, 9-Energy Probe-40, 9-Energy Probe-41 |
| | TCQ: 9-Energy Probe-55s |

For the purposes of settlement, the Parties accept the proposed rate riders to dispose of those account balances that are the subject of disposition at this time on a final basis. The Parties have agreed to dispose of the balances over the 18-month period from November 1, 2013 to April 30, 2015. Settlement Table #11: Deferral and Variance Account Disposition Balances below reflects the allocation by customer class of the balances being disposed.

# Settlement Table #11: Deferral and Variance Account Disposition Balances

| | USofA | Total Claim | Allocator | Residential | General Service < 50 kW | General Service > 50 kW | Unmetered Scattered Load | Street Lighting |
|---|---|---|---|---|---|---|---|---|
| LV Variance Account | 1550 | $169,833 | kWh | $64,227 | $25,618 | $78,594 | $227 | $1,167 |
| RSVA - Wholesale Market Service Charge | 1580 | ($490,313) | kWh | ($185,425) | ($73,960) | ($226,903) | ($655) | ($3,370) |
| RSVA - Retail Transmission Network Charge | 1584 | ($2,556) | kWh | ($967) | ($386) | ($1,183) | ($3) | ($18) |
| RSVA - Retail Transmission Connection Charge | 1586 | ($26,474) | kWh | ($10,012) | ($3,993) | ($12,252) | ($35) | ($182) |
| RSVA - Power (excluding Global Adjustment) | 1588 | $141,511 | kWh | $53,516 | $21,346 | $65,487 | $189 | $973 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | $574,290 | Non-RPP kWh | $42,602 | $19,097 | $505,089 | $0 | $7,501 |
| Disposition and Recovery/Refund of Regulatory Balances (2009) | 1595 | ($106,818) | kWh | ($40,396) | ($16,113) | ($49,432) | ($143) | ($734) |
| Disposition and Recovery/Refund of Regulatory Balances (2010) | 1595 | ($2,265) | kWh | ($857) | ($342) | ($1,048) | ($3) | ($16) |
| Total of Group 1 Accounts (excluding 1588 sub-account) | | ($317,082) | | ($119,913) | ($47,830) | ($146,737) | ($423) | ($2,179) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | $60,881 | # of Customers | $53,698 | $6,615 | $440 | $116 | $12 |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | | # of Customers | | | | | |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $11,635 | # of Customers | $10,262 | $1,264 | $84 | $22 | $2 |
| Renewable Generation Connection Capital Deferral Account | 1531 | | # of Customers | | | | | |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | # of Customers | | | | | |
| Smart Grid Capital Deferral Account | 1534 | $7,142 | # of Customers | $6,299 | $776 | $52 | $14 | $1 |
| Smart Grid OM&A Deferral Account | 1535 | $12,808 | # of Customers | $11,297 | $1,392 | $93 | $24 | $2 |
| Other Deferred Credits | 2425 | ($83,625) | # of Customers | ($73,759) | ($9,086) | ($605) | ($159) | ($16) |
| Total of Group 2 Accounts | | $8,839 | | $7,796 | $960 | $64 | $17 | $2 |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | ($56,411) | Revenue | ($36,522) | ($9,043) | ($8,895) | ($74) | ($1,877) |
| Total of Account 1562 and Account 1592 | | ($56,411) | | ($36,522) | ($9,043) | ($8,895) | ($74) | ($1,877) |
| Total Balance Allocated (excluding 1588 sub-account) | | ($364,654) | | ($148,639) | ($55,912) | ($155,567) | ($481) | ($4,054) |
| Total Balance in Account 1588 - sub account | | $574,290 | | $42,602 | $19,097 | $505,089 | $0 | $7,501 |
| Total Balance Allocated (including 1588 sub-account) | | $209,636 | | ($106,037) | ($36,816) | $349,522 | ($481) | $3,447 |

Settlement Tables #12 and #13 show the calculated rate riders for disposition of Deferral and Variance Account balances over the 18-month period from November 1, 2013 to April 30, 2015.

**Settlement Table #12: Deferral and Variance Account Disposition Rate Riders (excluding Global Adjustment)**

| Rate Class | Units | kW / kWh | Allocated Balance | Rate Rider |
|---|---|---|---|---|
| Residential | kWh | 116,182,693 | $ (148,639) | (0.0009) |
| General Service < 50 kW | kWh | 46,341,631 | $ (55,912) | (0.0008) |
| General Service > 50 kW | kW | 327,346 | $ (155,567) | (0.3168) |
| Unmetered Scattered Load | kWh | 410,208 | $ (481) | (0.0008) |
| Street Lighting | kW | 6,087 | $ (4,054) | (0.4441) |
| Total | | | $ (364,654) | |

**Settlement Table #13: Deferral and Variance Account Disposition Rate Riders – Global Adjustment**

| Rate Class | Units | kW / kWh for Non-RPP Customers | Allocated Balance | Rate Rider |
|---|---|---|---|---|
| Residential | kWh | 11,991,607 | $ 42,602 | 0.0024 |
| General Service < 50 kW | kWh | 5,375,333 | $ 19,097 | 0.0024 |
| General Service > 50 kW | kW | 327,346 | $ 505,089 | 1.0287 |
| Unmetered Scattered Load | kWh | 0 | $ - | - |
| Street Lighting | kW | 6,087 | $ 7,501 | 0.8216 |
| Total | | | $ 574,290 | |

## 10.0 GREEN ENERGY ACT PLAN

### 10.1 Is Collus PowerStream's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

---

| | |
|---|---|
| **Status:** | **Complete Settlement** |
| Supporting Parties: | Collus PowerStream, Energy Probe, SEC, VECC |
| Evidence: | Application: Exhibit 2, Tab 5, Schedule 1 |
| | IRR: 4.0-VECC-28 |

For the purposes of settlement, the Parties accept Collus PowerStream's basic Green Energy Act Plan. The 2013 Cost of Service Rate Application does not include any funding rate riders relating to the Green Energy Act. Only historical costs related to the Green Energy Act up to December 31, 2011, included in section 9.1 above, are being recovered as part of the deferral and variance account disposition.

**Appendix A: Summary of Significant Changes**

| | As filed | Settlement | Change | Notes |
|---|---|---|---|---|
| **Rate Base:** | | | | |
| Net Fixed Assets | $ 15,699,377 | $ 15,555,827 | $ (143,550) | 1 |
| Working Capital Base (WCB) | $ 35,028,620 | $ 34,058,571 | $ (970,049) | 2 |
| Working Capital Factor(WCF) | 13.0% | 12.0% | | |
| Working Capital Allowance (WCA) | $ 4,553,721 | $ 4,087,028 | $ (466,693) | 2 |
| **Total Rate Base** | **$ 20,253,098** | **$ 19,642,855** | **$ (610,243)** | |
| **Revenue Requirement:** | | | | |
| Deemed Debt | $ 475,891 | $ 461,552 | $ (14,339) | |
| Return on Equity (ROE) | $ 727,492 | $ 705,571 | $ (21,921) | |
| **Total Return on Rate Base** | **$ 1,203,383** | **$ 1,167,123** | **$ (36,260)** | 3 |
| OM&A | $ 4,755,160 | $ 4,585,160 | $ (170,000) | 4 |
| Depreciation | $ 948,979 | $ 940,212 | $ (8,767) | 5 |
| Income taxes (grossed-up) | $ 73,876 | $ 67,958 | $ (5,918) | 6 |
| **Service Revenue Requirement** | **$ 6,981,398** | **$ 6,760,453** | **$ (220,945)** | |
| Revenue Offsets | $ 465,600 | $ 480,405 | $ 14,805 | 7 |
| **Base Revenue Requirement** | **$ 6,515,798** | **$ 6,280,048** | **$ (235,750)** | |

**NOTES**

1. Change in average net fixed assets results from removal of replaced smart meters in the amount of $32,000 in 2012 and $184,000 in 2013 plus a reduction of $50,000 in 2013 capital additions. This is offset in part by reduced depreciation expense of $ 1,067 in 2012 and $8,767 in 2013, which reduces accumulated depreciation.
2. The reduction in working capital allowance (WCA) is the combined result of a reduced working capital base (WCB) and a reduction in the working capital factor (WCF). The WCB reduction is made up of a decrease in the cost of power of $656,050, a decrease in OM&A of $170,000 and removal of $144,000 regarding depreciation included in OM&A. The change in working capital factor from 13% to 12% applied to the lower WCB results in the decreased WCA.
3. The reduced return on rate base is attributable to the decrease in rate base times the weighted cost of capital of 5.94%, which is unchanged from the filing.
4. OM&A has been reduced as per the terms of the settlement proposal.
5. Depreciation reduction in due to the lower capital amounts for 2013 as described in note 1 above.
6. The reduction in income taxes is attributable to the lower ROE resulting from changes in the Rate Base.
7. Increase in revenue offsets is as per section 3.5 of the settlement proposal.

## Schedule 2-B
## Fixed Asset Continuity Schedule [CGAAP]
## 31-Dec-12

| | | | | Cost | | | | Accumulated Depreciation | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CCA Class | OEB AC# | Description | Depreciation Rate | Opening Balance | Additions | Disposals | Closing Balance | Opening Balance | Additions | Disposals | Closing Balance | Net Book Value |
| N/A | 1805 | Land | NA | $ 95,439 | $ 361,109 | | $ 456,548 | $ - | | | $ - | $ 456,548 |
| 1 | 1808 | Buildings & Fixtures Substations - 60 years | 60 years | $ 446,277 | $ 108,735 | | $ 555,012 | $ (31,294) | $ (9,265) | | $ (40,559) | $ 514,453 |
| 1 | 1808 | Buildings & fixtures Other - 30 years | 30 years | $ 47,865 | | | $ 47,865 | $ (43,080) | $ (1,595) | | $ (44,675) | $ 3,190 |
| 47 | 1820 | Dist Stat Equip below 50KV | 30 years | $ 5,219,952 | $ 1,258 | | $ 5,221,210 | $ (1,735,518) | $ (165,243) | | $ (1,900,761) | $ 3,320,449 |
| 47 | 1830 | Poles, Towers & Fixtures | 25 years | $ 644,500 | $ 333,695 | | $ 978,195 | $ (45,050) | $ (39,123) | | $ (84,173) | $ 894,022 |
| 47 | 1835 | Overhead Conductors & Devices | 25 years | $ 11,606,414 | $ 578,191 | | $ 12,184,605 | $ (6,419,877) | $ (452,219) | | $ (6,872,096) | $ 5,312,509 |
| 47 | 1845 | Underground Conductors & Devices | 25 years | $ 8,324,434 | $ 230,763 | | $ 8,555,197 | $ (4,496,027) | $ (337,926) | | $ (4,833,953) | $ 3,721,244 |
| 47 | 1850 | Line Transformers | 25 years | $ 5,578,931 | $ 112,722 | | $ 5,691,653 | $ (2,783,086) | $ (210,842) | | $ (2,993,927) | $ 2,697,725 |
| 47 | 1855 | Services | 25 years | $ 954,481 | $ 139,385 | | $ 1,093,865 | $ (183,956) | $ (43,764) | | $ (227,719) | $ 866,146 |
| 47 | 1995 | Contributions & Grants | 25 years | $ (10,231,780) | $ (339,434) | | $ (10,571,214) | $ 3,884,782 | $ 422,858 | | $ 4,307,640 | $ (6,263,574) |
| 47 | 2055 | Construction Work in Process | NA | $ 121,872 | $ (95,339) | | $ 26,533 | $ - | | | $ - | $ 26,533 |
| 47 | 1860 | Meters | 15 years | $ 441,653 | $ 50,052 | | $ 491,705 | $ (53,946) | $ (32,777) | | $ (86,723) | $ 404,981 |
| 47 | 1860 | Stranded Meters | 25 years | $ 1,529,891 | | $ 1,529,891 | $ - | $ (970,627) | $ (31,907) | $ 1,002,534 | $ - | $ - |
| 47 | 1860 | Smart Meters | 15 years | | $ 2,606,507 | $ 32,000 | $ 2,574,507 | | $ (642,963) | | $ (642,963) | $ 1,931,545 |
| 8 | 1915 | Office Furniture & Equipment | 10 years | $ 191,478 | $ 16,531 | | $ 208,009 | $ (130,788) | $ (11,769) | | $ (142,557) | $ 65,452 |
| 8 | 1920 | Computer Equipment | 3 years | $ 18,014 | | | $ 18,014 | $ (6,004) | $ (6,005) | | $ (12,009) | $ 6,005 |
| 12 | 1925 | Computer Software | 5 years | $ 511,378 | $ 4,225 | | $ 515,603 | $ (323,814) | $ (91,349) | | $ (415,163) | $ 100,440 |
| 10 | 1930 | Transportation Equipment | 5 or 8 years | $ 1,611,428 | $ 263,420 | | $ 1,874,847 | $ (826,961) | $ (179,188) | | $ (1,006,149) | $ 868,699 |
| 8 | 1935 | Stores Equipment | 10 years | $ 12,000 | | | $ 12,000 | $ (2,400) | $ (1,200) | | $ (3,600) | $ 8,400 |
| 8 | 1945 | Measurement & Testing Equipment | | $ 51,800 | | | $ 51,800 | $ (51,800) | | | $ (51,800) | $ - |
| 8 | 1950 | Power Operated Equipment | 10 years | $ 37,260 | | | $ 37,260 | $ (29,808) | $ (3,726) | | $ (33,534) | $ 3,726 |
| 8 | 1955 | Communication Equipment | 10 years | $ 71,751 | | | $ 71,751 | $ (60,171) | $ (3,100) | | $ (63,271) | $ 8,480 |
| 8 | 1960 | Miscellaneous Equipment | 10 years | $ 239,174 | | | $ 239,174 | $ (213,822) | $ (3,536) | | $ (217,358) | $ 21,816 |
| 8 | 1980 | System Supervisory Equipment | 15 years | $ 672,850 | | | $ 672,850 | $ (349,440) | $ (42,390) | | $ (391,830) | $ 281,020 |
| | | **Sub-total** | | **$ 28,197,062** | **$ 4,371,819** | **$ 1,561,891** | **$ 31,006,990** | **$ (14,872,687)** | **$ (1,887,028)** | **$ 1,002,534** | **$ (15,757,181)** | **$ 15,249,809** |
| | | Less AC# 2055 CWIP | | $ (121,872) | $ 95,339 | $ - | $ (26,533) | $ - | $ - | $ - | $ - | $ (26,533) |
| | | **Total** | | **$ 28,075,190** | **$ 4,467,158** | **$ 1,561,891** | **$ 30,980,457** | **$ (14,872,687)** | **$ (1,887,028)** | **$ 1,002,534** | **$ (15,757,181)** | **$ 15,223,276** |

***Less fully allocated depreciation:***

| | |
|---|---|
| Transportation | $ 179,188 |
| Other amortization expense | |
| Deferred charges | $ (8,155) |
| Stranded meters | $ (22,791) |
| Net Depreciation | $ (1,738,786) |

# Schedule 2-B
## Fixed Asset Continuity Schedule
## 31-Dec-13

**[MCGAAP]**

| | | | | Cost | | | | Accumulated Depreciation | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CCA Class** | **OEB AC#** | **Description** | **Depreciation Rate** | **Opening Balance** | **Additions** | **Disposals** | **Closing Balance** | **Opening Balance** | **Additions** | **Disposals** | **Closing Balance** | **Net Book Value** |
| N/A | 1805 | Land | NA | $ 456,548 | | | $ 456,548 | $ - | | | $ - | $ 456,548 |
| 1 | 1808 | Buildings & Fixtures Substations - 60 years | 60 years | $ 555,012 | | | $ 555,012 | $ (40,559) | $ (9,250) | | $ (49,809) | $ 505,203 |
| 1 | 1808 | Buildings & fixtures Other - 30 years | 30 years | $ 47,865 | | | $ 47,865 | $ (44,675) | $ (1,595) | | $ (46,270) | $ 1,595 |
| 47 | 1820 | Dist Stat Equip below 50KV | 20-50 yrs | $ 5,221,210 | | | $ 5,221,210 | $ (1,900,761) | $ (132,672) | | $ (2,033,433) | $ 3,187,777 |
| 47 | 1830 | Poles, Towers & Fixtures | 45 & 60 yrs | $ 978,195 | $ 558,422 | | $ 1,536,617 | $ (84,173) | $ (170,566) | | $ (254,739) | $ 1,281,878 |
| 47 | 1835 | Overhead Conductors & Devices | 45 & 60 yrs | $ 12,184,605 | $ 496,343 | | $ 12,680,948 | $ (6,872,096) | $ (112,461) | $ (10,000) | $ (6,994,557) | $ 5,686,391 |
| 47 | 1845 | Underground Conductors & Devices | 40 & 50 years | $ 8,555,197 | $ 214,879 | | $ 8,770,076 | $ (4,833,953) | $ (137,032) | $ (10,000) | $ (4,980,985) | $ 3,789,091 |
| 47 | 1850 | Line Transformers | 40 & 45 years | $ 5,691,653 | $ 206,064 | | $ 5,897,717 | $ (2,993,927) | $ (113,327) | $ (10,000) | $ (3,117,254) | $ 2,780,463 |
| 47 | 1855 | Services | 40 years | $ 1,093,865 | $ 150,000 | | $ 1,243,865 | $ (227,719) | $ (31,328) | | $ (259,047) | $ 984,818 |
| 47 | 1995 | Contributions & Grants | 40 & 45 years | $ (10,571,214) | $ (350,000) | | $ (10,921,214) | $ 4,307,640 | $ 191,833 | | $ 4,499,473 | $ (6,421,741) |
| 47 | 2055 | Construction Work in Process | NA | $ 26,533 | | | $ 26,533 | $ - | | | $ - | $ 26,533 |
| 47 | 1860 | Meters | 15 years | $ 491,705 | | | $ 491,705 | $ (86,723) | $ (32,780) | | $ (119,504) | $ 372,201 |
| 47 | 1860 | Stranded Meters | 25 years | $ - | | | $ - | $ - | | | $ - | $ - |
| 47 | 1860 | Smart Meters | 15 years | $ 2,574,507 | $ 275,500 | $ 184,000 | $ 2,666,007 | $ (642,963) | $ (173,098) | | $ (816,060) | $ 1,849,947 |
| 8 | 1915 | Office Furniture & Equipment | 10 years | $ 208,009 | | | $ 208,009 | $ (142,557) | $ (11,768) | | $ (154,325) | $ 53,684 |
| 8 | 1920 | Computer Equipment | 3 years | $ 18,014 | | | $ 18,014 | $ (12,009) | $ (6,005) | | $ (18,014) | $ - |
| 12 | 1925 | Computer Software | 5 year | $ 515,603 | $ 105,000 | | $ 620,603 | $ (415,163) | $ (110,081) | | $ (525,244) | $ 95,359 |
| 10 | 1930 | Transportation Equipment | 5 or 8 years | $ 1,874,847 | $ 202,000 | | $ 2,076,847 | $ (1,006,149) | $ (192,047) | | $ (1,198,196) | $ 878,652 |
| 8 | 1935 | Stores Equipment | 10 years | $ 12,000 | | | $ 12,000 | $ (3,600) | $ (1,200) | | $ (4,800) | $ 7,200 |
| 8 | 1945 | Measurement & Testing Equipment | | $ 51,800 | | | $ 51,800 | $ (51,800) | | | $ (51,800) | $ - |
| 8 | 1950 | Power Operated Equipment | 10 years | $ 37,260 | | | $ 37,260 | $ (33,534) | $ (3,726) | | $ (37,260) | $ - |
| 8 | 1955 | Communication Equipment | 10 years | $ 71,751 | | | $ 71,751 | $ (63,271) | $ (3,100) | | $ (66,371) | $ 5,380 |
| 8 | 1960 | Miscellaneous Equipment | 10 years | $ 239,174 | $ 75,000 | | $ 314,174 | $ (217,358) | $ (7,286) | | $ (224,644) | $ 89,530 |
| 8 | 1980 | System Supervisory Equipment | 15 years | $ 672,850 | $ 40,000 | | $ 712,850 | $ (391,830) | $ (36,616) | | $ (428,446) | $ 284,405 |
| | | **Sub-total** | | **$ 31,006,990** | **$ 1,973,208** | **$ 184,000** | **$ 32,796,198** | **$ (15,757,181)** | **$ (1,094,104)** | **$ (30,000)** | **$ (16,881,285)** | **$ 15,914,913** |
| | | Less AC#2055 CWIP | | $ (26,533) | $ - | $ - | $ (26,533) | $ - | $ - | $ - | $ - | $ (26,533) |
| | | Total | | **$ 30,980,457** | **$ 1,973,208** | **$ 184,000** | **$ 32,769,665** | **$ (15,757,181)** | **$ (1,094,104)** | **$ (30,000)** | **$ (16,881,285)** | **$ 15,888,380** |

| | |
|---|---|
| Less Fully allocated depreciation: | |
| Transportation | $ 192,047 |
| Plus other amortization expense: | |
| Deferred charges | $ (8,155) |
| Net Depreciation | $ (910,212) |

## 2013 COP Expense Forecast

| Components | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **VOLUMES** | | | | | | | | | | | | | |
| Total Purchases (kWh) | 31,084,003 | *28,198,086* | *28,130,699* | *23,391,114* | *22,406,499* | *22,710,051* | *23,977,523* | *24,375,631* | *22,072,289* | *23,571,977* | *24,822,012* | *29,602,809* | **304,342,694** |
| | | | | | | | | | | | | | |
| RPP Customer Base | 51.53% | 46.82% | 43.38% | 41.70% | 39.85% | 42.46% | 50.24% | 45.69% | 43.48% | 46.72% | 51.49% | 57.63% | |
| Spot Customer Base | 48.47% | 53.18% | 56.62% | 58.30% | 60.15% | 57.54% | 49.76% | 54.31% | 56.52% | 53.28% | 48.51% | 42.37% | |
| | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | |
| | | | | | | | | | | | | | |
| RPP kWh | 16,019,048 | 13,203,443 | 12,203,941 | 9,753,931 | 8,928,699 | 9,643,505 | 12,046,547 | 11,137,202 | 9,596,833 | 11,013,276 | 12,780,730 | 17,061,165 | **143,388,319** |
| Non-RPP kWh | 15,064,955 | 14,994,642 | 15,926,758 | 13,637,183 | 13,477,800 | 13,066,546 | 11,930,976 | 13,238,430 | 12,475,456 | 12,558,702 | 12,041,282 | 12,541,645 | **160,954,375** |
| | | | | | | | | | | | | | |
| **Historic Ratios (kW)**3 | | | | | | | | | | | | | |
| System kW/Energy Purchased kWh - HONI | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | 0.18% | |
| System Line/System kW - HONI | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | 8.06% | |
| Low Voltage/System kW - HONI | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | 100.04% | |
| | | | | | | | | | | | | | |
| **kW Quantities** | | | | | | | | | | | | | |
| Transmission Network - HONI | 57,350 | 52,025 | 51,901 | 43,156 | 41,340 | 41,900 | 44,238 | 44,973 | 40,723 | 43,490 | 45,796 | 54,617 | **561,508** |
| Transmission Line - HONI | 4,625 | 4,195 | 4,185 | 3,480 | 3,334 | 3,379 | 3,567 | 3,627 | 3,284 | 3,507 | 3,693 | 4,404 | **45,282** |
| LV Charges - HONI | 57,371 | 52,044 | 51,920 | 43,172 | 41,355 | 41,915 | 44,255 | 44,989 | 40,738 | 43,506 | 45,813 | 54,637 | **561,715** |
| | | | | | | | | | | | | | |
| **RATES** | | | | | | | | | | | | | |
| Commodity (RPP) | 0.08069 | 0.07938 | 0.07938 | 0.07938 | 0.08395 | 0.08395 | 0.08395 | 0.08395 | 0.08395 | 0.08395 | 0.08395 | 0.08395 | **0.08254** |
| Commodity (Spot) | 0.02040 | 0.02464 | 0.02464 | 0.02464 | 0.01933 | 0.01933 | 0.01933 | 0.01933 | 0.01933 | 0.01933 | 0.01933 | 0.01933 | **0.02075** |
| Global Adjustment Rate/kWh | 0.05381 | 0.05426 | 0.04064 | 0.04064 | 0.06612 | 0.06612 | 0.06612 | 0.06612 | 0.06612 | 0.06612 | 0.06612 | 0.06612 | **0.05986** |
| Transmission Network - HONI | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | **3.1800** |
| Transmission Line - HONI | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | 0.7000 | **0.7000** |
| Transmission Transformation - HONI | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | 1.6300 | **1.6300** |
| LV Charges - HONI | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | 0.6680 | **0.6680** |
| Wholesale Market Charge (per kWh) | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | 0.0056 | **0.0056** |
| Monthly Service charges (fixed per account) | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | 292.56 | **292.56** |
| LVDS (per kW) | 1.9440 | 1.94 | 1.94 | 1.94 | 1.94 | 1.94 | 1.94 | 1.94 | 1.94 | 1.94 | 1.94 | 1.94 | **1.9440** |
| | | | | | | | | | | | | | |
| **COP EXPENSE** | | | | | | | | | | | | | |
| Commodity (RPP) | $ 1,292,577 | $ 1,048,089 | $ 968,749 | $ 774,267 | $ 749,564 | $ 809,572 | $ 1,011,308 | $ 934,968 | $ 805,654 | $ 924,564 | $ 1,072,942 | $ 1,432,285 | **$ 11,824,540** |
| Commodity (Spot) | 1,117,970 | 1,183,077 | 1,039,699 | 890,235 | 1,151,678 | 1,116,536 | 1,019,502 | 1,131,224 | 1,066,028 | 1,073,141 | 1,028,928 | 1,071,684 | **$ 12,889,702** |
| Transmission Network - HONI | 182,372 | 165,440 | 165,044 | 137,237 | 131,460 | 133,241 | 140,678 | 143,013 | 129,499 | 138,298 | 145,632 | 173,681 | **$ 1,785,596** |
| Transmission Line - HONI | 3,237 | 2,937 | 2,930 | 2,436 | 2,334 | 2,365 | 2,497 | 2,539 | 2,299 | 2,455 | 2,585 | 3,083 | **$ 31,697** |
| Transmission Transformation - HONI | 93,480 | 84,801 | 84,598 | 70,345 | 67,384 | 68,297 | 72,108 | 73,306 | 66,379 | 70,889 | 74,648 | 89,025 | **$ 915,259** |
| LV Charges - HONI | 38,324 | 34,766 | 34,683 | 28,839 | 27,625 | 27,999 | 29,562 | 30,053 | 27,213 | 29,062 | 30,603 | 36,497 | **$ 375,226** |
| Wholesale Market Charge | 174,070 | 157,909 | 157,532 | 130,990 | 125,476 | 127,176 | 134,274 | 136,504 | 123,605 | 132,003 | 139,003 | 165,776 | **$ 1,704,319** |
| Monthly Service charges (8 accounts) | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | 2,340 | **$ 28,086** |
| LVDS (on average 2,700 kW) | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | 5,249 | **$ 62,986** |
| **Total Cost of Power** | **$ 2,909,619** | **$ 2,684,608** | **$ 2,460,824** | **$ 2,041,939** | **$ 2,263,111** | **$ 2,292,777** | **$ 2,417,518** | **$ 2,459,195** | **$ 2,228,266** | **$ 2,378,002** | **$ 2,501,931** | **$ 2,979,621** | **$ 29,617,410** |

**Table 1: CDM Savings for Load Forecast Adjustment**

| Year | OPA Programs | 3rd Tranche | Revised CDM Targets 2011-2014 | Total CDM Savings | Loss Factor | Loss Factor, kWh Gross-up | CDM Savings, kWh (gross) | Monthly |
|---|---|---|---|---|---|---|---|---|
| **2005** | | 158,967 | 0 | **158,967** | 8.8% | 14,037 | 173,004 | 14,417 |
| **2006** | 1,031,866 | 1,236,756 | 0 | **2,268,622** | 8.4% | 190,111 | 2,458,733 | 204,894 |
| **2007** | 2,580,762 | 436,092 | 0 | **3,016,854** | 8.4% | 252,812 | 3,269,666 | 272,472 |
| **2008** | 3,577,935 | 220,405 | 0 | **3,798,340** | 8.4% | 318,301 | 4,116,641 | 343,053 |
| **2009** | 5,621,541 | 0 | 0 | **5,621,541** | 7.5% | 421,616 | 6,043,157 | 503,596 |
| **2010** | 6,099,488 | 0 | 0 | **6,099,488** | 7.5% | 457,462 | 6,556,950 | 546,412 |
| **2011** | 5,698,064 | 0 | 410,187 | **6,108,251** | 7.5% | 458,119 | 6,566,369 | 547,197 |
| **2012** | 5,615,213 | 0 | 1,301,450 | **6,916,663** | 7.5% | 518,750 | 7,435,412 | 619,618 |
| **2013** | 5,589,642 | 0 | 3,264,040 | **8,853,682** | 7.0% | 619,758 | 9,473,440 | **789,453** |
| **2014** | 5,426,277 | 0 | 6,140,032 | **11,566,309** | 7.0% | 809,642 | 12,375,951 | 1,031,329 |
| | | | **11,115,708** | | | | | |

NOTE: 2011-2014 CDM Targets are adjusted for a "half-year" rule (as per terms of the Settlement Agreement)

**Table 3: Load Forecast Model Input (Annualized)**

| Year | Gross Actual Load | Customer Count | HDD | CDD |
|---|---|---|---|---|
| 2005 | 294,751,814 | 12,142 | 3,967.2 | 421.3 |
| 2006 | 291,145,722 | 12,242 | 3,561.9 | 285.3 |
| 2007 | 295,363,784 | 12,535 | 3,935.0 | 293.8 |
| 2008 | 298,019,872 | 12,771 | 3,981.9 | 214.2 |
| 2009 | 299,265,351 | 13,140 | 3,970.8 | 123.8 |
| 2010 | 302,998,832 | 13,549 | 3,716.2 | 338.2 |
| 2011 | 306,141,293 | 13,735 | 3,792.5 | 286.9 |
| 2012 Projected (Jan-Sep Actuals) | 304,412,996 | 14,055 | 3,453.4 | 345.1 |
| **2013 Test - Forecast** | | **14,383** | **3,882.7** | **281.5** |

**Table 2: Energy Purchases Net of CDM**

| Year | Actual Load Gross | CDM (Half-year rule) | Actual Load (IESO) | Weather-Normal Actual Gross | Weather-Normal Actual Net | Growth, % |
|---|---|---|---|---|---|---|
| 2005 | 294,751,814 | 173,004 | 294,578,809 | 289,248,267 | 289,075,263 | |
| 2006 | 291,145,722 | 2,458,733 | 288,686,990 | 295,436,591 | 292,977,859 | 1.4% |
| 2007 | 295,363,784 | 3,269,666 | 292,094,117 | 294,262,960 | 290,993,294 | -0.7% |
| 2008 | 298,019,872 | 4,116,641 | 293,903,231 | 298,746,878 | 294,630,237 | 1.2% |
| 2009 | 299,265,351 | 6,043,157 | 293,222,194 | 302,952,757 | 296,909,600 | 0.8% |
| 2010 | 302,998,832 | 6,556,950 | 296,441,882 | 303,525,998 | 296,969,049 | 0.0% |
| 2011 | 306,141,293 | 6,566,369 | 299,574,924 | 307,213,227 | 300,646,858 | 1.2% |
| 2012 Projected (Jan-Sep Actuals) | 304,412,996 | 7,435,412 | 296,977,584 | 309,813,706 | 302,378,294 | 0.6% |
| **2013 Test - Forecast (Normalized 10-year)** | | **9,473,440** | | **313,738,001** | **304,264,561** | **0.6%** |

**Table 4: 2013 Load (kW)**

| Rate Class | 2013 | | | | | | | | | | | | 2013 FY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | |
| | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | |
| Residential | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| GS<50 | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| GS>50 | 31,995 | 28,940 | 27,456 | 25,161 | 25,701 | 29,310 | 29,752 | 27,440 | 26,479 | 27,632 | 30,411 | 32,131 | **342,409** |
| USL | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Street Lighting | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | **6,285** |
| **Total** | **32,519** | **29,464** | **27,980** | **25,685** | **26,225** | **29,834** | **30,275** | **27,964** | **27,003** | **28,156** | **30,935** | **32,655** | **348,694** |

**Table 5: 2013 Consumption (kWh)**

| | 2013 | | | | | | | | | | | | 2013 FY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | |
| | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | |
| Residential | 13,250,014 | 12,145,550 | 12,350,532 | 9,501,697 | 8,660,342 | 7,486,472 | 8,324,512 | 9,341,390 | 7,739,292 | 8,575,727 | 8,847,790 | 11,733,273 | **117,956,589** |
| GS<50 | 4,601,874 | 4,132,780 | 4,343,869 | 3,616,387 | 3,350,061 | 3,580,401 | 3,778,290 | 3,907,413 | 3,660,941 | 3,805,817 | 3,721,973 | 4,674,060 | **47,173,865** |
| GS>50 | 10,876,988 | 9,838,552 | 9,333,880 | 8,553,752 | 8,737,362 | 9,964,325 | 10,114,305 | 9,328,476 | 9,001,690 | 9,393,703 | 10,338,466 | 10,923,313 | **116,404,810** |
| USL | 32,426 | 32,510 | 35,241 | 29,567 | 35,193 | 33,497 | 31,546 | 33,412 | 29,763 | 36,094 | 37,410 | 36,846 | **403,504** |
| Street Lighting | 260,205 | 180,405 | 189,809 | 134,080 | 135,050 | 137,220 | 132,265 | 144,410 | 170,470 | 192,305 | 226,906 | 262,613 | **2,165,737** |
| **Total** | **29,021,508** | **26,329,796** | **26,253,330** | **21,835,482** | **20,918,008** | **21,201,915** | **22,380,917** | **22,755,100** | **20,602,156** | **22,003,645** | **23,172,544** | **27,630,104** | **284,104,505** |

**Table 6: 2013 Customer Count**

| | 2013 | | | | | | | | | | | | 2013 FY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | |
| | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | Fcst | |
| Residential | 14,082 | 14,110 | 14,137 | 14,164 | 14,192 | 14,219 | 14,246 | 14,273 | 14,301 | 14,328 | 14,355 | 14,383 | **14,233** |
| GS<50 | 1,705 | 1,707 | 1,710 | 1,712 | 1,714 | 1,716 | 1,718 | 1,720 | 1,723 | 1,725 | 1,727 | 1,729 | **1,717** |
| GS>50 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | **117** |
| USL | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | **30** |
| Street Lighting | 3,026 | 3,030 | 3,033 | 3,036 | 3,040 | 3,043 | 3,047 | 3,050 | 3,053 | 3,057 | 3,060 | 3,063 | **3,045** |
| **Total** | **18,960** | **18,994** | **19,027** | **19,059** | **19,093** | **19,125** | **19,158** | **19,190** | **19,224** | **19,257** | **19,289** | **19,322** | **19,142** |

# Details of Other Operating Revenue

| | Other Operating Revenue | Board Approved | Historic Actual | | | | Test Year | |
|---|---|---|---|---|---|---|---|---|
| | | 2009 | 2009 | 2010 | 2011 | 2012 | 2013 | |
| 4235 | Miscellaneous Service Revenues | 155,000 | 149,517 | 199,352 | 173,436 | 185,406 | 164,000 | 3.0-VECC TCQ-50 b) Reduced by $40k |
| 4225 | Late Payment Charges | 55,000 | 94,277 | 99,511 | 118,839 | 130,330 | 84,000 | |
| 4078 | SSS Admin charge | - | - | - | 48,000 | 48,853 | 48,000 | 3.0-VECC TCQ-50 a) Add $48k |
| 4082 | Retail Services Revenues | 23,000 | 19,741 | 20,465 | 19,227 | 17,380 | 18,000 | |
| 4084 | Service Transaction Requests (STR) Revenues | 8,000 | (985) | (176) | (2,287) | 410 | 600 | |
| 4210 | Rent from Electric Property | 85,000 | 84,046 | 107,600 | 99,248 | 105,401 | 105,000 | |
| 4345 | Gains from Disposition of Future Use Utility Plant | - | - | - | - | 645 | - | |
| 4350 | Losses from Disposition of Future Use Utility Plant | - | - | - | - | - | - | Vehicle gain on disposal |
| 4355 | Gain on Disposition of Utility and Other Property | - | - | 8,852 | 320 | - | 4,600 | 3-EP-22 g) Add 4600 |
| 4370 | Losses from Disposition of Allowances for Emission | - | - | - | - | - | - | Micro-Fit |
| 4375 | Revenues from Non-Utility Operations | - | 661,916 | 566,471 | 222,609 | 327,702 | 2,205 | 3-EP-22 h) Add $2205 |
| 4380 | Expenses of Non-Utility Operations | - | (569,385) | (525,182) | (227,181) | (326,112) | 1,500 | |
| 4390 | Miscellaneous Non-Operating Income | - | 9,280 | 53,635 | 5,490 | 4,748 | 6,000 | |
| 4405 | Interest and Dividend Income | 46,000 | 58,644 | 46,626 | 30,617 | 37,452 | 48,000 | |
| **Total** | | **372,000** | **507,050** | **577,154** | **488,319** | **532,213** | **481,905** | |

v 2.0

# Income Tax/PILs Workform for 2013 Filers

| | |
|---|---|
| **Utility Name** | COLLUS Power Corp. |
| **Assigned EB Number** | EB-2012-0116 |
| **Name and Title** | Cindy Shuttleworth, Chief Financial Officer |
| **Phone Number** | 705.445.1800 (2270) |
| **Email Address** | cshuttleworth@collus.com |
| **Date** | 30-Apr-13 |
| **Last COS Re-based Year** | **2009** |

**Note: Drop-down lists are shaded blue; Input cells are shaded green.**



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

# Income Tax/PILs
# Workform for 2013 Filers

# Income Tax/PILs Workform for 2013 Filers

| | | | | | |
|---|---|---|---|---|---|
| **Rate Base** | | | **$** | **19,642,855** | |
| | | | | | |
| **Return on Ratebase** | | | | | |
| Deemed ShortTerm Debt % | 4.00% | T | $ | 785,714 | *W = S * T* |
| Deemed Long Term Debt % | 56.00% | U | $ | 10,999,999 | *X = S * U* |
| Deemed Equity % | 40.00% | V | $ | 7,857,142 | *Y = S * V* |
| | | | | | |
| Short Term Interest Rate | 2.07% | Z | $ | 16,264 | *AC = W * Z* |
| Long Term Interest | 4.05% | AA | $ | 445,288 | *AD = X * AA* |
| **Return on Equity (Regulatory Income)** | 8.98% | AB | **$** | **705,571** | *AE = Y * AB* |
| **Return on Rate Base** | | | **$** | **1,167,123** | *AF = AC + AD + AE* |

## Questions that must be answered

| | Historic | Bridge | Test Year |
|---|---|---|---|
| 1. Does the applicant have any Investment Tax Credits (ITC)? | Yes | No | No |
| 2. Does the applicant have any SRED Expenditures? | Yes | No | No |
| 3. Does the applicant have any Capital Gains or Losses for tax purposes? | No | No | No |
| 4. Does the applicant have any Capital Leases? | No | No | No |
| 5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)? | No | No | No |
| 6. Since 1999, has the applicant acquired another regulated applicant's assets? | Yes | Yes | Yes |
| 7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.* | No | No | No |
| 8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes? | No | No | No |

# Income Tax/PILs Workform for 2013 Filers

| **Tax Rates**<br>**Federal & Provincial**<br>**As of June 20, 2012** | **Effective**<br>################ | **Effective**<br>################ | **Effective**<br>################ | **Effective**<br>################ |
|---|---|---|---|---|
| **Federal income tax** | | | | |
| General corporate rate | 38.00% | 38.00% | 38.00% | 38.00% |
| Federal tax abatement | -10.00% | -10.00% | -10.00% | -10.00% |
| Adjusted federal rate | 28.00% | 28.00% | 28.00% | 28.00% |
| Rate reduction | -11.50% | -13.00% | -13.00% | -13.00% |
| | 16.50% | 15.00% | 15.00% | 15.00% |
| **Ontario income tax** | 11.75% | 11.50% | 11.50% | 11.50% |
| **Combined federal and Ontario** | 28.25% | 26.50% | 26.50% | 26.50% |
| **Federal & Ontario Small Business** | | | | |
| Federal small business threshold | 500,000 | 500,000 | 500,000 | 500,000 |
| Ontario Small Business Threshold | 500,000 | 500,000 | 500,000 | 500,000 |
| Federal small business rate | 11.00% | 11.00% | 11.00% | 11.00% |
| Ontario small business rate | 4.50% | 4.50% | 4.50% | 4.50% |

# Income Tax/PILs Workform for 2013 Filers

## Schedule 8 - Historical Year

| Class | Class Description | UCC End of Year Historic per tax returns | Less: Non-Distribution Portion | UCC Regulated Historic Year |
|---|---|---|---|---|
| 1 | Distribution System - post 1987 | 7,191,139 | | 7,191,139 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | | | 0 |
| 2 | Distribution System - pre 1988 | | | 0 |
| 8 | General Office/Stores Equip | 161,095 | | 161,095 |
| 10 | Computer Hardware/ Vehicles | 603,296 | | 603,296 |
| 10.1 | Certain Automobiles | | | 0 |
| 12 | Computer Software | 525 | | 525 |
| $13_{1}$ | Lease # 1 | | | 0 |
| $13_{2}$ | Lease #2 | | | 0 |
| $13_{3}$ | Lease # 3 | | | 0 |
| $13_{4}$ | Lease # 4 | | | 0 |
| 14 | Franchise | | | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | 0 |
| 42 | Fibre Optic Cable | | | 0 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | 0 |
| 43.2 | Certain Clean Energy Generation Equipment | | | 0 |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | | | 0 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | 0 |
| 47 | Distribution System - post February 2005 | 9,208,802 | | 9,208,802 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | 13,060 | | 13,060 |
| 52 | Computer Hardware and system software | | | 0 |
| 95 | CWIP | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | SUB-TOTAL - UCC | 17,177,917 | 0 | 17,177,917 |

# Income Tax/PILs Workform for 2013 Filers



## Schedule 10 CEC - Historical Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **582,665** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 0 | **x 3/4 =** | 0 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 0 | **0** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **582,665** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **582,665** |
| **Current Year Deduction** | | **582,665** | **x 7% =** | **40,787** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **541,878** |

# Income Tax/PILs Workform for 2013 Filers

## Schedule 13 Tax Reserves - Historical

### Continuity of Reserves

| Description | Historical Balance as per tax returns | Non-Distribution Eliminations | Utility Only |
|---|---|---|---|
| | | | |
| Capital Gains Reserves ss.40(1) | | | 0 |
| **Tax Reserves Not Deducted for accounting purposes** | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | | | 0 |
| Reserve for goods and services not delivered ss. 20(1)(m) | | | 0 |
| Reserve for unpaid amounts ss. 20(1)(n) | | | 0 |
| Debt & Share Issue Expenses ss. 20(1)(e) | | | 0 |
| Other tax reserves | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| **Total** | **0** | **0** | **0** |
| | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | |
| General Reserve for Inventory Obsolescence (non-specific) | | | 0 |
| General reserve for bad debts | | | 0 |
| Accrued Employee Future Benefits: | 336,820 | | 336,820 |
| - Medical and Life Insurance | | | 0 |
| -Short & Long-term Disability | | | 0 |
| -Accmulated Sick Leave | | | 0 |
| - Termination Cost | | | 0 |
| - Other Post-Employment Benefits | | | 0 |
| Provision for Environmental Costs | | | 0 |
| Restructuring Costs | | | 0 |
| Accrued Contingent Litigation Costs | | | 0 |
| Accrued Self-Insurance Costs | | | 0 |
| Other Contingent Liabilities | | | 0 |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | | | 0 |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | | | 0 |
| Other | | | 0 |
| | | | |
| | | | |
| | | | |
| | | | 0 |
| | | | 0 |
| **Total** | **336,820** | **0** | **336,820** |

# Income Tax/PILs Workform for 2013 Filers

## Schedule 7-1 Loss Carry Forward - Historic

## Corporation Loss Continuity and Application

| Non-Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual Historic | | | 0 |

| Net Capital Loss Carry Forward Deduction | Total | Non-Distribution Portion | Utility Balance |
|---|---|---|---|
| Actual Historic | | | 0 |

Income Tax/PILs
Workform for 2013 Filers

# Adjusted Taxable Income - Historic Year

| | T2S1 line # | Total for Legal Entity | Non-Distribution Eliminations | Historic Wires Only |
|---|---|---|---|---|
| **Income before PILs/Taxes** | A | 468,411 | | 468,411 |
| **Additions:** | | | | |
| Interest and penalties on taxes | 103 | | | 0 |
| Amortization of tangible assets | 104 | 1,053,169 | | 1,053,169 |
| Amortization of intangible assets | 106 | | | 0 |
| Recapture of capital cost allowance from Schedule 8 | 107 | | | 0 |
| Gain on sale of eligible capital property from Schedule 10 | 108 | | | 0 |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | | | 0 |
| Loss in equity of subsidiaries and affiliates | 110 | | | 0 |
| Loss on disposal of assets | 111 | | | 0 |
| Charitable donations | 112 | | | 0 |
| Taxable Capital Gains | 113 | | | 0 |
| Political Donations | 114 | | | 0 |
| Deferred and prepaid expenses | 116 | | | 0 |
| Scientific research expenditures deducted on financial statements | 118 | | | 0 |
| Capitalized interest | 119 | | | 0 |
| Non-deductible club dues and fees | 120 | | | 0 |
| Non-deductible meals and entertainment expense | 121 | 1,000 | | 1,000 |
| Non-deductible automobile expenses | 122 | | | 0 |
| Non-deductible life insurance premiums | 123 | | | 0 |
| Non-deductible company pension plans | 124 | | | 0 |
| Tax reserves deducted in prior year | 125 | | | 0 |
| Reserves from financial statements- balance at end of year | 126 | 336,820 | | 336,820 |
| Soft costs on construction and renovation of buildings | 127 | | | 0 |
| Book loss on joint ventures or partnerships | 205 | | | 0 |
| Capital items expensed | 206 | | | 0 |
| Debt issue expense | 208 | | | 0 |
| Development expenses claimed in current year | 212 | | | 0 |
| Financing fees deducted in books | 216 | | | 0 |
| Gain on settlement of debt | 220 | | | 0 |
| Non-deductible advertising | 226 | | | 0 |
| Non-deductible interest | 227 | | | 0 |
| Non-deductible legal and accounting fees | 228 | | | 0 |
| Recapture of SR&ED expenditures | 231 | | | 0 |
| Share issue expense | 235 | | | 0 |
| Write down of capital property | 236 | | | 0 |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | | | 0 |
| ***Other Additions*** | | | | |
| Interest Expensed on Capital Leases | 290 | | | 0 |
| Realized Income from Deferred Credit Accounts | 291 | | | 0 |
| Pensions | 292 | | | 0 |
| Non-deductible penalties | 293 | | | 0 |
| Tax provision expense | 294 | 125,438 | | 125,438 |
| Provincial ITCS related to PPA section 9 inclusion | 295 | 4,097 | | 4,097 |
| ARO Accretion expense | | | | 0 |
| Capital Contributions Received (ITA 12(1)(x)) | | | | 0 |
| Lease Inducements Received (ITA 12(1)(x)) | | | | 0 |
| Deferred Revenue (ITA 12(1)(a)) | | | | 0 |
| Prior Year Investment Tax Credits received | | | | 0 |
| Amortization contained in other expenses | | 152,728 | | 152,728 |

| | | | | |
|---|---|---|---|---|
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Additions** | | **1,673,252** | **0** | **1,673,252** |
| | | | | |
| **Deductions:** | | | | |
| Gain on disposal of assets per financial statements | 401 | 320 | | 320 |
| Dividends not taxable under section 83 | 402 | | | 0 |
| Capital cost allowance from Schedule 8 | 403 | 1,212,578 | | 1,212,578 |
| Terminal loss from Schedule 8 | 404 | | | 0 |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 40,787 | | 40,787 |
| Allowable business investment loss | 406 | | | 0 |
| Deferred and prepaid expenses | 409 | | | 0 |
| Scientific research expenses claimed in year | 411 | 219,502 | | 219,502 |
| Tax reserves claimed in current year | 413 | | | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 308,029 | | 308,029 |
| Contributions to deferred income plans | 416 | | | 0 |
| Book income of joint venture or partnership | 305 | | | 0 |
| Equity in income from subsidiary or affiliates | 306 | | | 0 |
| *Other deductions: (Please explain in detail the nature of the item)* | | | | |
| | | | | |
| Interest capitalized for accounting deducted for tax | 390 | | | 0 |
| Capital Lease Payments | 391 | | | 0 |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | | | 0 |
| | 393 | | | 0 |
| | 394 | | | 0 |
| ARO Payments - Deductible for Tax when Paid | | | | 0 |
| ITA 13(7.4) Election - Capital Contributions Received | | | | 0 |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | | | 0 |
| Deferred Revenue - ITA 20(1)(m) reserve | | | | 0 |
| Principal portion of lease payments | | | | 0 |
| Lease Inducement Book Amortization credit to income | | | | 0 |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | |
| **Total Deductions** | | **1,781,216** | **0** | **1,781,216** |
| | | | | |
| **Net Income for Tax Purposes** | | **360,447** | **0** | **360,447** |
| | | | | |
| Charitable donations from Schedule 2 | 311 | | | 0 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | | | 0 |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | | | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | | | 0 |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | | | 0 |
| | | | | |
| **TAXABLE INCOME** | | **360,447** | **0** | **360,447** |

# Income Tax/PILs Workform for 2013 Filers

## PILs Tax Provision - Historic Year

**Note: Input the actual information from the tax returns for the historic year.**

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 360,447 | **A** |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.75% | **B** | $ 42,345 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction (negative) | 7.25% | **E** | -$ 26,125 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 16,220 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 4.50% | **K = J / A** | | |
| | Federal tax rate | | | 12.90% | **L** | | |
| | Combined tax rate | | | | | 17.40% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 62,731** | **N = A * M** |
| Investment Tax Credits | | | | | | $ 46,511 | **O** |
| Miscellaneous Tax Credits | | | | | | $ 10,150 | **P** |
| **Total Tax Credits** | | | | | | **$ 56,661** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Historic Year** | | | | | | **$ 6,070** | **R = N - Q** |

# Income Tax/PILs Workform for 2013 Filers

## Schedule 8 CCA - Bridge Year

| Class | Class Description | UCC Regulated Historic Year | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Bridge Year CCA | UCC End of Bridge Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 7,191,139 | $ 108,735 | | $ 7,299,874 | $ 54,368 | $ 7,245,507 | 4% | $ 289,820 | $ 7,010,054 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | | | | $ - | $ - | $ - | 6% | $ - | $ - |
| 2 | Distribution System - pre 1988 | | | | $ - | $ - | $ - | 6% | $ - | $ - |
| 8 | General Office/Stores Equip | $ 161,095 | $ 16,531 | | $ 177,626 | $ 8,266 | $ 169,361 | 20% | $ 33,872 | $ 143,754 |
| 10 | Computer Hardware/ Vehicles | $ 603,296 | $ 263,420 | | $ 866,716 | $ 131,710 | $ 735,006 | 30% | $ 220,502 | $ 646,214 |
| 10.1 | Certain Automobiles | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 525 | $ 4,225 | | $ 4,750 | $ 2,113 | $ 2,638 | 100% | $ 2,638 | $ 2,113 |
| 13 1 | Lease # 1 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | | | | $ - | $ - | $ - | 12% | $ - | $ - |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | | | | $ - | $ - | $ - | 45% | $ - | $ - |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 9,208,802 | $ 1,011,291 | | $ 10,220,093 | $ 505,646 | $ 9,714,448 | 8% | $ 777,156 | $ 9,442,937 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 13,060 | | | $ 13,060 | $ - | $ 13,060 | 55% | $ 7,183 | $ 5,877 |
| 52 | Computer Hardware and system software | | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | | | | | $ - | $ - | $ - | | $ - | $ - |
| | TOTAL | $ 17,177,917 | $ 1,404,202 | $ - | $ 18,582,119 | $ 702,101 | $ 17,880,018 | | $ 1,331,170 | $ 17,250,949 |

Income Tax/PILs
Workform for 2013 Filers

# Schedule 10 CEC - Bridge Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **541,878** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | | | | |
| Other Adjustments | 0 | | | |
| Subtotal | 0 | **x 3/4 =** | 0 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 0 | **0** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **541,878** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **541,878** |
| **Current Year Deduction** | | **541,878** | **x 7% =** | **37,931** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **503,947** |


## Schedule 13 Tax Reserves - Bridge Year

### Continuity of Reserves

| Description | Historic Utility Only | Eliminate Amounts Not Relevant for Bridge Year | Adjusted Utility Balance | Bridge Year Adjustments: Additions | Bridge Year Adjustments: Disposals | Balance for Bridge Year | Change During the Year | Disallowed Expenses |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 336,820 | | 336,820 | -352 | | 336,468 | -352 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **336,820** | **0** | **336,820** | **-352** | **0** | **336,468** | **-352** | **0** |

# Income Tax/PILs Workform for 2013 Filers

## Corporation Loss Continuity and Application

## Schedule 7-1 Loss Carry Forward - Bridge Year

| **Non-Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historic | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | |
| Other Adjustments Add (+) Deduct (-) | |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | |
| Balance available for use post Bridge Year | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** |
|---|---|
| Actual Historic | 0 |
| Application of Loss Carry Forward to reduce taxable income in Bridge Year | |
| Other Adjustments Add (+) Deduct (-) | |
| Balance available for use in Test Year | 0 |
| **Amount to be used in Bridge Year** | |
| Balance available for use post Bridge Year | 0 |

Income Tax/PILs
Workform for 2013 Filers

# Adjusted Taxable Income - Bridge Year

| | T2S1 line # | Total for Regulated Utility |
|---|---|---|
| **Income before PILs/Taxes** | **A** | 680,119 |

| | | |
|---|---|---|
| **Additions:** | | |
| Interest and penalties on taxes | 103 | |
| Amortization of tangible assets | 104 | 1,888,095 |
| Amortization of intangible assets | 106 | |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | |
| Non-deductible meals and entertainment expense | 121 | 1,000 |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves deducted in prior year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 336,468 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |

Income Tax/PILs
Workform for 2013 Filers

# Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| ***Other Additions*** | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **2,225,563** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 1,331,170 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 37,931 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves claimed in current year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 336,820 |
| Contributions to deferred income plans | 416 | |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| | | |

Income Tax/PILs
Workform for 2013 Filers

# Adjusted Taxable Income - Bridge Year

| | | |
|---|---|---|
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **1,705,922** |
| | | |
| **Net Income for Tax Purposes** | | **1,199,760** |
| Charitable donations from Schedule 2 | 311 | |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **TAXABLE INCOME** | | **1,199,760** |

# Income Tax/PILs Workform for 2013 Filers

## PILS Tax Provision - Bridge Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 1,199,760 | A |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 11.50% | **B** | $ 137,972 | **C = A * B** | | |
| *Small business credit* | Ontario Small Business Threshold | $ 500,000 | **D** | | | | |
| | Rate reduction | -7.00% | **E** | -$ 35,000 | **F = D * E** | | |
| *Ontario Income tax* | | | | | | $ 102,972 | **J = C + F** |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 8.58% | **K = J / A** | | |
| | Federal tax rate | | | 15.00% | **L** | | |
| | Combined tax rate | | | | | 23.58% | **M = K + L** |
| **Total Income Taxes** | | | | | | **$ 282,936** | **N = A * M** |
| Investment Tax Credits | | | | | | | **O** |
| Miscellaneous Tax Credits | | | | | | | **P** |
| **Total Tax Credits** | | | | | | **$ -** | **Q = O + P** |
| **Corporate PILs/Income Tax Provision for Bridge Year** | | | | | | **$ 282,936** | **R = N - Q** |

**Note:**

**1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.**

# Income Tax/PILs Workform for 2013 Filers

## Schedule 8 CCA - Test Year

| Class | Class Description | UCC Test Year Opening Balance | Additions | Disposals (Negative) | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | Test Year CCA | UCC End of Test Year |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - post 1987 | $ 7,010,054 | | | $ 7,010,054 | $ - | $ 7,010,054 | 4% | $ 280,402 | $ 6,729,652 |
| 1 Enhanced | Non-residential Buildings Reg. 1100(1)(a.1) election | $ - | | | $ - | $ - | $ - | 6% | $ - | $ - |
| 2 | Distribution System - pre 1988 | $ - | | | $ - | $ - | $ - | 6% | $ - | $ - |
| 8 | General Office/Stores Equip | $ 143,754 | 115,000 | | $ 258,754 | $ 57,500 | $ 201,254 | 20% | $ 40,251 | $ 218,503 |
| 10 | Computer Hardware/ Vehicles | $ 646,214 | 202,000 | | $ 848,214 | $ 101,000 | $ 747,214 | 30% | $ 224,164 | $ 624,050 |
| 10.1 | Certain Automobiles | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 12 | Computer Software | $ 2,113 | 105,000 | | $ 107,113 | $ 52,500 | $ 54,613 | 100% | $ 54,613 | $ 52,500 |
| 13 1 | Lease # 1 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 2 | Lease #2 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 3 | Lease # 3 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 13 4 | Lease # 4 | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 14 | Franchise | $ - | | | $ - | $ - | $ - | | $ - | $ - |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl | $ - | | | $ - | $ - | $ - | 8% | $ - | $ - |
| 42 | Fibre Optic Cable | $ - | | | $ - | $ - | $ - | 12% | $ - | $ - |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 43.2 | Certain Clean Energy Generation Equipment | $ - | | | $ - | $ - | $ - | 50% | $ - | $ - |
| 45 | Computers & Systems Software acq'd post Mar 22/04 | $ - | | | $ - | $ - | $ - | 45% | $ - | $ - |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | $ - | | | $ - | $ - | $ - | 30% | $ - | $ - |
| 47 | Distribution System - post February 2005 | $ 9,442,937 | 1,601,208 | | $ 11,044,145 | $ 800,604 | $ 10,243,541 | 8% | $ 819,483 | $ 10,224,662 |
| 50 | Data Network Infrastructure Equipment - post Mar 2007 | $ 5,877 | | | $ 5,877 | $ - | $ 5,877 | 55% | $ 3,232 | $ 2,645 |
| 52 | Computer Hardware and system software | $ - | | | $ - | $ - | $ - | 100% | $ - | $ - |
| 95 | CWIP | $ - | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | | | | | $ - | $ - | $ - | 0% | $ - | $ - |
| | TOTAL | $ 17,250,949 | $ 2,023,208 | $ - | $ 19,274,157 | $ 1,011,604 | $ 18,262,553 | | $ 1,422,145 | $ 17,852,011 |

# Income Tax/PILs Workform for 2013 Filers



## Schedule 10 CEC - Test Year

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | **503,947** |
| **Additions** | | | | |
| Cost of Eligible Capital Property Acquired during Test Year | 0 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | 0 | |
| Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002 | 0 | **x 1/2 =** | 0 | |
| | | | 0 | **0** |
| Amount transferred on amalgamation or wind-up of subsidiary | 0 | | | **0** |
| **Subtotal** | | | | **503,947** |
| **Deductions** | | | | |
| Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year | 0 | | | |
| Other Adjustments | 0 | | | |
| **Subtotal** | 0 | **x 3/4 =** | | **0** |
| **Cumulative Eligible Capital Balance** | | | | **503,947** |
| **Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")** | | **503,947** | **x 7% =** | **35,276** |
| **Cumulative Eligible Capital - Closing Balance** | | | | **468,671** |

# Income Tax/PILs Workform for 2013 Filers

## Schedule 13 Tax Reserves - Test Year

### Continuity of Reserves

| Description | Bridge Year | Eliminate Amounts Not Relevant for Bridge Year | Adjusted Utility Balance | Test Year Adjustments | | Balance for Test Year | Change During the Year | Disallowed Expenses |
|---|---|---|---|---|---|---|---|---|
| | | | | Additions | Disposals | | | |
| | | | | | | | | |
| Capital Gains Reserves ss.40(1) | 0 | | 0 | | | 0 | 0 | |
| **Tax Reserves Not Deducted for accounting purposes** | | | | | | | | |
| Reserve for doubtful accounts ss. 20(1)(l) | 0 | | 0 | | | 0 | 0 | |
| Reserve for goods and services not delivered ss. 20(1)(m) | 0 | | 0 | | | 0 | 0 | |
| Reserve for unpaid amounts ss. 20(1)(n) | 0 | | 0 | | | 0 | 0 | |
| Debt & Share Issue Expenses ss. 20(1)(e) | 0 | | 0 | | | 0 | 0 | |
| Other tax reserves | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| | | | | | | | | |
| **Financial Statement Reserves (not deductible for Tax Purposes)** | | | | | | | | |
| General Reserve for Inventory Obsolescence (non-specific) | 0 | | 0 | | | 0 | 0 | |
| General reserve for bad debts | 0 | | 0 | | | 0 | 0 | |
| Accrued Employee Future Benefits: | 336,468 | | 336,468 | 18,461 | | 354,929 | 18,461 | |
| - Medical and Life Insurance | 0 | | 0 | | | 0 | 0 | |
| -Short & Long-term Disability | 0 | | 0 | | | 0 | 0 | |
| -Accmulated Sick Leave | 0 | | 0 | | | 0 | 0 | |
| - Termination Cost | 0 | | 0 | | | 0 | 0 | |
| - Other Post-Employment Benefits | 0 | | 0 | | | 0 | 0 | |
| Provision for Environmental Costs | 0 | | 0 | | | 0 | 0 | |
| Restructuring Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Contingent Litigation Costs | 0 | | 0 | | | 0 | 0 | |
| Accrued Self-Insurance Costs | 0 | | 0 | | | 0 | 0 | |
| Other Contingent Liabilities | 0 | | 0 | | | 0 | 0 | |
| Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4) | 0 | | 0 | | | 0 | 0 | |
| Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1) | 0 | | 0 | | | 0 | 0 | |
| Other | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| | 0 | | 0 | | | 0 | 0 | |
| **Total** | **336,468** | **0** | **336,468** | **18,461** | **0** | **354,929** | **18,461** | **0** |

# Income Tax/PILs Workform for 2013 Filers

## Schedule 7-1 Loss Carry Forward - Test Year

## Corporation Loss Continuity and Application

| **Non-Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual/Estimated Bridge Year | | | 0 |
| Application of Loss Carry Forward to reduce taxable income in 2005 | | | 0 |
| Other Adjustments Add (+) Deduct (-) | | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

| **Net Capital Loss Carry Forward Deduction** | **Total** | **Non-Distribution Portion** | **Utility Balance** |
|---|---|---|---|
| Actual/Estimated Bridge Year | | | 0 |
| Application of Loss Carry Forward to reduce taxable income in 2005 | | | 0 |
| Other Adjustments Add (+) Deduct (-) | | | 0 |
| Balance available for use in Test Year | 0 | 0 | 0 |
| **Amount to be used in Test Year** | | | 0 |
| Balance available for use post Test Year | 0 | 0 | 0 |

# Income Tax/PILs Workform for 2013 Filers

## Taxable Income - Test Year

| | T2 S1 line # | Test Year Taxable Income |
|---|---|---|
| ***Net Income Before Taxes*** | | 705,571 |
| **Additions:** | | |
| Interest and penalties on taxes | 103 | |
| Amortization of tangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P489* | 104 | |
| Amortization of intangible assets<br>*2-4 ADJUSTED ACCOUNTING DATA P490* | 106 | 1,102,871 |
| Recapture of capital cost allowance from Schedule 8 | 107 | |
| Gain on sale of eligible capital property from Schedule 10 | 108 | |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | |
| Loss in equity of subsidiaries and affiliates | 110 | |
| Loss on disposal of assets | 111 | |
| Charitable donations | 112 | |
| Taxable Capital Gains | 113 | |
| Political Donations | 114 | |
| Deferred and prepaid expenses | 116 | |
| Scientific research expenditures deducted on financial statements | 118 | |
| Capitalized interest | 119 | |
| Non-deductible club dues and fees | 120 | |
| Non-deductible meals and entertainment expense | 121 | 1,000 |
| Non-deductible automobile expenses | 122 | |
| Non-deductible life insurance premiums | 123 | |
| Non-deductible company pension plans | 124 | |
| Tax reserves beginning of year | 125 | 0 |
| Reserves from financial statements- balance at end of year | 126 | 354,929 |
| Soft costs on construction and renovation of buildings | 127 | |
| Book loss on joint ventures or partnerships | 205 | |
| Capital items expensed | 206 | |
| Debt issue expense | 208 | |
| Development expenses claimed in current year | 212 | |
| Financing fees deducted in books | 216 | |
| Gain on settlement of debt | 220 | |
| Non-deductible advertising | 226 | |
| Non-deductible interest | 227 | |
| Non-deductible legal and accounting fees | 228 | |
| Recapture of SR&ED expenditures | 231 | |
| Share issue expense | 235 | |
| Write down of capital property | 236 | |

| | | |
|---|---|---|
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | |
| *Other Additions: (please explain in detail the nature of the item)* | | |
| Interest Expensed on Capital Leases | 290 | |
| Realized Income from Deferred Credit Accounts | 291 | |
| Pensions | 292 | |
| Non-deductible penalties | 293 | |
| | 294 | |
| | 295 | |
| | 296 | |
| | 297 | |
| ARO Accretion expense | | |
| Capital Contributions Received (ITA 12(1)(x)) | | |
| Lease Inducements Received (ITA 12(1)(x)) | | |
| Deferred Revenue (ITA 12(1)(a)) | | |
| Prior Year Investment Tax Credits received | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Additions** | | **1,458,800** |
| **Deductions:** | | |
| Gain on disposal of assets per financial statements | 401 | |
| Dividends not taxable under section 83 | 402 | |
| Capital cost allowance from Schedule 8 | 403 | 1,422,145 |
| Terminal loss from Schedule 8 | 404 | |
| Cumulative eligible capital deduction from Schedule 10 CEC | 405 | 35,276 |
| Allowable business investment loss | 406 | |
| Deferred and prepaid expenses | 409 | |
| Scientific research expenses claimed in year | 411 | |
| Tax reserves end of year | 413 | 0 |
| Reserves from financial statements - balance at beginning of year | 414 | 336,468 |
| Contributions to deferred income plans | 416 | |
| Book income of joint venture or partnership | 305 | |
| Equity in income from subsidiary or affiliates | 306 | |
| *Other deductions: (Please explain in detail the nature of the item)* | | |
| Interest capitalized for accounting deducted for tax | 390 | |
| Capital Lease Payments | 391 | |

| | | |
|---|---|---|
| Non-taxable imputed interest income on deferral and variance accounts | 392 | |
| | 393 | |
| | 394 | |
| | 395 | |
| | 396 | |
| | 397 | |
| ARO Payments - Deductible for Tax when Paid | | |
| ITA 13(7.4) Election - Capital Contributions Received | | |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | |
| Deferred Revenue - ITA 20(1)(m) reserve | | |
| Principal portion of lease payments | | |
| Lease Inducement Book Amortization credit to income | | |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| **Total Deductions** | | **1,793,890** |
| | | |
| **NET INCOME FOR TAX PURPOSES** | | **370,482** |
| | | |
| Charitable donations | 311 | |
| Taxable dividends received under section 112 or 113 | 320 | |
| Non-capital losses of preceding taxation years from Schedule 7-1 | 331 | |
| Net-capital losses of preceding taxation years (Please show calculation) | 332 | |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | |
| | | |
| **REGULATORY TAXABLE INCOME** | | **370,482** |

# Income Tax/PILs Workform for 2013 Filers

## PILs Tax Provision - Test Year

| | | | | | | Wires Only | |
|---|---|---|---|---|---|---|---|
| **Regulatory Taxable Income** | | | | | | $ 370,482 | A |
| **Ontario Income Taxes** | | | | | | | |
| *Income tax payable* | **Ontario Income Tax** | 4.50% | B | $ 16,672 | C = A * B | | |
| *Small business credit* | Ontario Small Business Threshold | $ - | D | | | | |
| | Rate reduction | -7.00% | E | $ - | F = D * E | | |
| *Ontario Income tax* | | | | | | $ 16,672 | J = C + F |
| **Combined Tax Rate and PILs** | Effective Ontario Tax Rate | | | 4.50% | K = J / A | | |
| | Federal tax rate | | | 11.00% | L | | |
| | Combined tax rate | | | | | 15.50% | M = K + L |
| **Total Income Taxes** | | | | | | $ 57,425 | N = A * M |
| Investment Tax Credits | | | | | | | O |
| Miscellaneous Tax Credits | | | | | | | P |
| **Total Tax Credits** | | | | | | $ - | Q = O + P |
| **Corporate PILs/Income Tax Provision for Test Year** | | | | | | $ 57,425 | R = N - Q |
| Corporate PILs/Income Tax Provision Gross Up [1] | | | | 84.50% | S = 1 - M | $ 10,534 | T = R / S - R |
| **Income Tax** (grossed-up) | | | | | | $ 67,958 | U = R + T |

**Note:**

**1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.**

# Appendix G

# DRAFT RATE ORDER

# COLLUS PowerStream Corp

# 2013 Electrcity Distribution Rates

# EB-2012-0116

# October 1, 2013

# COLLUS PowerStream Corp
# TARIFF OF RATES AND CHARGES
### Effective October 1, 2013
### Implemented November 1, 2013

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

EB-2012-0116

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately 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. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk

**APPLICATION**

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 9.88 |
| Stranded Meter Rate Rider - Effective until April 30, 2015 | $ | 1.39 |
| Rate Rider for Recovery of Forgone Revenue - Effective until April 30, 2014 | $ | 0.41 |
| Distribution Volumetric Rate | $/kWh | 0.0193 |
| Low Voltage Charge | $/kWh | 0.0016 |
| Rate Rider for Deferral/Variance Account disposition (2010) -- Effective until April 30, 2014 | $/kWh | (0.0026) |
| Rate Rider for Deferral/Variance Account disposition (2012) -- Effective until April 30, 2014 | $/kWh | (0.0032) |
| Rate Rider for Deferral/Variance Account disposition (2013) -- Effective until April 30, 2015 | $/kWh | (0.0009) |
| Rate Rider for Global Adjustment sub-Account disposition (2013) | | |
| Applicable only for non-RPP customers - Effective until April 30, 2015 | $/kWh | 0.0024 |
| Smart Meter Entity Charge | $ | 0.79 |
| Retail Transmission Rate – Network Service Rate | $/kWh | 0.0067 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | 0.0037 |

**MONTHLY RATES AND CHARGES – Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0012 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# COLLUS PowerStream Corp
# TARIFF OF RATES AND CHARGES
## Effective October 1, 2013
## Implemented November 1, 2013

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

EB-2012-0116

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 19.74 |
| Stranded Meter Rate Rider - Effective until April 30, 2015 | $ | 3.21 |
| Rate Rider for Recovery of Forgone Revenue - Effective until April 30, 2014 | $ | 0.98 |
| Distribution Volumetric Rate | $/kWh | 0.0131 |
| Low Voltage Charge | $/kWh | 0.0014 |
| Rate Rider for Deferral/Variance Account disposition (2010) -- Effective until April 30, 2014 | $/kWh | (0.0024) |
| Rate Rider for Deferral/Variance Account disposition (2012) -- Effective until April 30, 2014 | $/kWh | (0.0029) |
| Rate Rider for Deferral/Variance Account disposition (2013) -- Effective until April 30, 2015 | $/kWh | (0.0008) |
| Rate Rider for Global Adjustment sub-Account disposition (2013) | | |
| Applicable only for non-RPP customers - Effective until April 30, 2015 | $/kWh | 0.0024 |
| Smart Meter Entity Charge | $ | 0.79 |
| Retail Transmission Rate – Network Service Rate | $/kWh | 0.0062 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | 0.0031 |

**MONTHLY RATES AND CHARGES – Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0012 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# COLLUS PowerStream Corp
# TARIFF OF RATES AND CHARGES
### Effective October 1, 2013
### Implemented November 1, 2013

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

EB-2012-0116

## GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service

**APPLICATION**

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 94.34 |
| Rate Rider for Recovery of Forgone Revenue - Effective until April 30, 2014 | $ | 2.21 |
| Distribution Volumetric Rate | $/kW | 3.0850 |
| Low Voltage Charge | $/kW | 0.5215 |
| Rate Rider for Deferral/Variance Account disposition (2010) -- Effective until April 30, 2014 | $/kW | (0.9907) |
| Rate Rider for Deferral/Variance Account disposition (2012) -- Effective until April 30, 2014 | $/kW | (1.1273) |
| Rate Rider for Deferral/Variance Account disposition (2013) -- Effective until April 30, 2015 | $/kW | (0.3168) |
| Rate Rider for Global Adjustment sub-Account disposition (2012) Applicable only for non-RPP customers - Effective until April 30, 2014 | $/kW | 0.8435 |
| Rate Rider for Global Adjustment sub-Account disposition (2013) Applicable only for non-RPP customers - Effective until April 30, 2015 | $/kW | 1.0287 |
| Retail Transmission Rate – Network Service Rate | $/kW | 2.4666 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kW | 1.2764 |

**MONTHLY RATES AND CHARGES – Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0012 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# COLLUS PowerStream Corp
# TARIFF OF RATES AND CHARGES
### Effective October 1, 2013
### Implemented November 1, 2013

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

EB-2012-0116

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak 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 customer will provide

**APPLICATION**

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 0.46 |
| Rate Rider for Recovery of Forgone Revenue - Effective until April 30, 2014 | $ | (1.12) |
| Distribution Volumetric Rate | $/kWh | 0.0113 |
| Low Voltage Charge | $/kWh | 0.0014 |
| Rate Rider for Deferral/Variance Account disposition (2010) -- Effective until April 30, 2014 | $/kWh | (0.0017) |
| Rate Rider for Deferral/Variance Account disposition (2012) -- Effective until April 30, 2014 | $/kWh | (0.0029) |
| Rate Rider for Deferral/Variance Account disposition (2013) -- Effective until April 30, 2015 | $/kWh | (0.0008) |
| Retail Transmission Rate – Network Service Rate | $/kWh | 0.0062 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | 0.0031 |

**MONTHLY RATES AND CHARGES – Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0012 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# COLLUS PowerStream Corp
# TARIFF OF RATES AND CHARGES
## Effective October 1, 2013
## Implemented November 1, 2013

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

EB-2012-0116

## 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 operation, 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

**APPLICATION**

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 3.45 |
| Rate Rider for Recovery of Forgone Revenue - Effective until April 30, 2014 | $ | 0.06 |
| Distribution Volumetric Rate | $/kW | 14.3874 |
| Low Voltage Charge | $/kW | 0.4031 |
| Rate Rider for Deferral/Variance Account disposition (2010) -- Effective until April 30, 2014 | $/kW | (0.7868) |
| Rate Rider for Deferral/Variance Account disposition (2012) -- Effective until April 30, 2014 | $/kW | (1.4363) |
| Rate Rider for Deferral/Variance Account disposition (2013) -- Effective until April 30, 2015 | $/kW | (0.4441) |
| Rate Rider for Global Adjustment sub-Account disposition (2013) | | |
| Applicable only for non-RPP customers - Effective until April 30, 2015 | $/kW | 0.8216 |
| Retail Transmission Rate – Network Service Rate | $/kW | 1.8602 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kW | 0.9867 |

**MONTHLY RATES AND CHARGES – Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate | $/kWh | 0.0044 |
| Rural Rate Protection Charge | $/kWh | 0.0012 |
| Standard Supply Service – Administrative Charge (if applicable) | $ | 0.25 |

# COLLUS PowerStream Corp
# TARIFF OF RATES AND CHARGES
## Effective October 1, 2013
## Implemented November 1, 2013

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

EB-2012-0116

## microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

**APPLICATION**

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit 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 beinvoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Programs, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# COLLUS PowerStream Corp
# TARIFF OF RATES AND CHARGES
### Effective October 1, 2013
### Implemented November 1, 2013

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

EB-2012-0116

## ALLOWANCES

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

## SPECIFIC SERVICE CHARGES

**APPLICATION**

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

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

**Customer Administration**

| | | |
|---|---|---|
| Charge to certify cheque | $ | 15.00 |
| Arrears certificate | $ | 15.00 |
| Statement of account | $ | 15.00 |
| Pulling post dated cheques | $ | 15.00 |
| Duplicate invoices for previous billing | $ | 15.00 |
| Account history | $ | 15.00 |
| Credit reference/creditcheck (plus credit agency costs) | $ | 15.00 |
| Returned cheque charge (plus bank charges) | $ | 15.00 |
| Legal letter charge | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 15.00 |
| 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 | $ | 20.00 |
| Collection of account charge - no disconnection - after regular hours | $ | 165.00 |
| Disconnect/Reconnect at meter - during regular hours | $ | 40.00 |
| Disconnect/Reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole - during regular hours | $ | 185.00 |
| Disconnect/Reconnect at pole - after regular hours | $ | 415.00 |
| Service call - after regular hours | $ | 165.00 |
| | | |
| Specific Charge for Access to the Power Poles - per pole/year | $ | 22.35 |

**LOSS FACTORS**

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

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0710 |
| Total Loss Factor – Secondary Metered Customer > 5,000 kW | N/A |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0603 |
| Total Loss Factor – Primary Metered Customer > 5,000 kW | N/A |

# RateRider for Revenue Differences (Effective vs. Implementation Dates)

| Rate Class | Revenue at Proposed Rates | Revenue at Current Rates | Annual Difference | Monthly Difference | # Customers/ Connections | Rate Rider |
|---|---|---|---|---|---|---|
| **Residential** | $ 3,964,991.44 | $ 3,542,372.02 | $ 422,619.42 | $ 35,218.28 | 14,233 | **$ 0.41** |
| **GS < 50 kW** | 1,025,094.01 | 903,560.55 | 121,533.46 | 10,127.79 | 1,717 | **$ 0.98** |
| **GS > 50 to 4,999 kW** | 1,068,760.60 | 954,843.84 | 113,916.76 | 9,493.06 | 717 | **$ 2.21** |
| **Streetlighting** | 216,481.00 | 202,753.26 | 13,727.74 | 1,143.98 | 3,045 | **$ 0.06** |
| **Unmetered Scattered Load** | 4,721.00 | 7,142.02 | (2,421.02) | (201.75) | 30 | **$ (1.12)** |
| **Total** | **$ 6,280,048.04** | **$ 5,610,671.69** | **$ 669,376.36** | **$ 55,781.36** | **19,742** | |

# Appendix 2-W
## Bill Impacts

**Customer Class:** **Residential**

**Consumption** 800 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

| | | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | **Charge Unit** | **Rate ($)** | **Volume** | **Charge ($)** | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | Monthly | $ 9.00 | 1 | $ 9.00 | $ 9.88 | 1 | $ 9.88 | $ 0.88 | 9.78% |
| Forgone Revenue Rider | Monthly | | 1 | $ - | $ 0.41 | 1 | $ 0.41 | $ 0.41 | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0170 | 800 | $ 13.60 | $ 0.0193 | 800 | $ 15.44 | $ 1.84 | 13.53% |
| Smart Meter Disposition Rider | Monthly | $ 3.5900 | 1 | $ 3.59 | | 1 | $ - | -$ 3.59 | -100.00% |
| | | | | | | | $ - | $ - | |
| | | | | | | | $ - | $ - | |
| | | | | | | | $ - | $ - | |
| | | | | | | | $ - | $ - | |
| | | | | | | | $ - | $ - | |
| | | | | | | | $ - | $ - | |
| | | | | | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| **Sub-Total A** | | | | $ 26.19 | | | $ 25.73 | **-$ 0.46** | **-1.76%** |
| Deferral/Variance Account Disposition Rate Rider | per kWh | -$ 0.0058 | 800 | -$ 4.64 | -$ 0.0067 | 800 | -$ 5.36 | -$ 0.72 | 15.52% |
| Stranded Meter Rate Rider | Monthly | | 1 | | $ 1.3900 | 1 | $ 1.39 | $ 1.39 | |
| Low Voltage Service Charge | per kWh | $ 0.0012 | 800 | $ 0.96 | $ 0.0016 | 800 | $ 1.28 | $ 0.32 | 33.33% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 23.30** | | | **$ 23.83** | **$ 0.53** | **2.27%** |
| RTSR - Network | per kWh | $ 0.0055 | 860 | $ 4.73 | $ 0.0067 | 857 | $ 5.71 | $ 0.98 | 20.68% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0033 | 860 | $ 2.84 | $ 0.0037 | 857 | $ 3.18 | $ 0.34 | 12.05% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 30.87** | | | **$ 32.72** | **$ 1.85** | **5.99%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 860 | $ 3.78 | $ 0.0044 | 857 | $ 3.77 | -$ 0.01 | -0.37% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0012 | 860 | $ 1.03 | $ 0.0012 | 857 | $ 1.03 | -$ 0.00 | -0.37% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0070 | 800 | $ 5.60 | $ 0.0070 | 800 | $ 5.60 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0750 | 600 | $ 45.00 | $ 0.0750 | 600 | $ 45.00 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.0880 | 260 | $ 22.88 | $ 0.0880 | 257 | $ 22.60 | -$ 0.28 | -1.23% |
| TOU - Off Peak | | $ 0.0650 | 550 | $ 35.78 | $ 0.0650 | 548 | $ 35.64 | -$ 0.13 | -0.37% |
| TOU - Mid Peak | | $ 0.1000 | 155 | $ 15.48 | $ 0.1000 | 154 | $ 15.42 | -$ 0.06 | -0.37% |
| TOU - On Peak | | $ 0.1170 | 155 | $ 18.11 | $ 0.1170 | 154 | $ 18.04 | -$ 0.07 | -0.37% |
| **Total Bill on RPP (before Taxes)** | | | | **$ 109.41** | | | **$ 110.96** | **$ 1.55** | **1.42%** |
| HST | | 13% | | $ 14.22 | 13% | | $ 14.43 | $ 0.20 | 1.42% |
| **Total Bill** (including HST) | | | | $ 123.64 | | | $ 125.39 | $ 1.75 | 1.42% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 12.36 | | | -$ 12.54 | -$ 0.18 | 1.46% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 111.28** | | | **$ 112.85** | **$ 1.57** | **1.41%** |
| **Total Bill on TOU (before Taxes)** | | | | **$ 110.90** | | | **$ 112.48** | **$ 1.57** | **1.42%** |
| HST | | 13% | | $ 14.42 | 13% | | $ 14.62 | $ 0.20 | 1.42% |
| **Total Bill** (including HST) | | | | $ 125.32 | | | $ 127.10 | $ 1.78 | 1.42% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 12.53 | | | -$ 12.71 | -$ 0.18 | 1.44% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 112.79** | | | **$ 114.39** | **$ 1.60** | **1.42%** |
| **Loss Factor (%)** | | 7.5000% | | | 7.10% | | | | |

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010*.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

## Appendix 2-W
## Bill Impacts

**Customer Class:** **General Service Less Than 50KW**

**Consumption** 2000 **kWh**

| | | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | **Charge Unit** | **Rate ($)** | **Volume** | **Charge ($)** | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | Monthly | $ 17.98 | 1 | $ 17.98 | $ 19.74 | 1 | $ 19.74 | $ 1.76 | 9.79% |
| Forgone Revenue Rider | Monthly | | 1 | $ - | $ 0.9800 | 1 | $ 0.98 | $ 0.98 | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0113 | 2000 | $ 22.60 | $ 0.0131 | 2000 | $ 26.20 | $ 3.60 | 15.93% |
| Smart Meter Disposition Rider | Monthly | $ 7.2900 | 1 | $ 7.29 | | 1 | $ - | -$ 7.29 | -100.00% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| **Sub-Total A** | | | | $ 47.87 | | | $ 46.92 | **-$ 0.95** | **-1.98%** |
| Deferral/Variance Account Disposition Rate Rider | per kWh | -$ 0.0053 | 2000 | -$ 10.60 | -$ 0.0061 | 2000 | -$ 12.20 | -$ 1.60 | 15.09% |
| Stranded Meter Rate Rider | Monthly | | 1 | $ - | $ 3.21 | 1 | $ 3.21 | $ 3.21 | |
| | | | | | | | | | |
| Low Voltage Service Charge | per kWh | $ 0.0011 | 2000 | $ 2.20 | $ 0.0014 | 2000 | $ 2.80 | $ 0.60 | 27.27% |
| Smart Meter Entity Charge | Monthly | $ 0.7900 | 1 | $ 0.79 | $ 0.7900 | 1 | $ 0.79 | $ - | 0.00% |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 40.26** | | | **$ 41.52** | **$ 1.26** | **3.13%** |
| RTSR - Network | per kWh | $ 0.0051 | 2150 | $ 10.97 | $ 0.0062 | 2142 | $ 13.23 | $ 2.27 | 20.68% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0028 | 2150 | $ 6.02 | $ 0.0031 | 2142 | $ 6.75 | $ 0.73 | 12.05% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 57.25** | | | **$ 61.50** | **$ 4.25** | **7.43%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 2150 | $ 9.46 | $ 0.0044 | 2142 | $ 9.42 | -$ 0.04 | -0.37% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0012 | 2150 | $ 2.58 | $ 0.0012 | 2142 | $ 2.57 | -$ 0.01 | -0.37% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0070 | 2000 | $ 14.00 | $ 0.0070 | 2000 | $ 14.00 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0750 | 750 | $ 56.25 | $ 0.0750 | 750 | $ 56.25 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.0880 | 1400 | $ 123.20 | $ 0.0880 | 1392 | $ 122.50 | -$ 0.70 | -0.57% |
| TOU - Off Peak | | $ 0.0650 | 1376 | $ 89.44 | $ 0.0650 | 1371 | $ 89.11 | -$ 0.33 | -0.37% |
| TOU - Mid Peak | | $ 0.1000 | 387 | $ 38.70 | $ 0.1000 | 386 | $ 38.56 | -$ 0.14 | -0.37% |
| TOU - On Peak | | $ 0.1170 | 387 | $ 45.28 | $ 0.1170 | 386 | $ 45.11 | -$ 0.17 | -0.37% |
| | | | | | | | | | |
| **Total Bill on RPP (before Taxes)** | | | | **$ 262.99** | | | **$ 266.49** | **$ 3.50** | **1.33%** |
| HST | | 13% | | $ 34.19 | 13% | | $ 34.64 | $ 0.46 | 1.33% |
| **Total Bill** (including HST) | | | | $ 297.17 | | | $ 301.13 | $ 3.96 | 1.33% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 29.72 | | | -$ 30.11 | -$ 0.39 | 1.31% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 267.45** | | | **$ 271.02** | **$ 3.57** | **1.33%** |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 256.95** | | | **$ 260.52** | **$ 3.56** | **1.39%** |
| HST | | 13% | | $ 33.40 | 13% | | $ 33.87 | $ 0.46 | 1.39% |
| **Total Bill** (including HST) | | | | $ 290.36 | | | $ 294.38 | $ 4.03 | 1.39% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 29.04 | | | -$ 29.44 | -$ 0.40 | 1.38% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 261.32** | | | **$ 264.94** | **$ 3.63** | **1.39%** |
| | | | | | | | | | |
| **Loss Factor (%)** | | 7.5000% | 2150 | | 7.10% | | | | |

## Appendix 2-W
## Bill Impacts

**Customer Class:** **General Service 50 to 4999 kW**

**Consumption** 86000 kWh | **Consumption** 250 KW

| | | Current Board-Approved | | | Proposed | | | Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | **Charge Unit** | **Rate ($)** | **Volume** | **Charge ($)** | **Rate ($)** | **Volume** | **Charge ($)** | **$ Change** | **% Change** |
| Monthly Service Charge | Monthly | $ 114.02 | 1 | $ 114.02 | $ 94.34 | 1 | $ 94.34 | -$ 19.68 | -17.26% |
| Forgone Revenue Rider | Monthly | | 1 | $ - | $ 2.21 | 1 | $ 2.21 | $ 2.21 | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 2.6400 | 250 | $ 660.00 | $ 3.0850 | 250 | $ 771.25 | $ 111.25 | 16.86% |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| **Sub-Total A** | | | | $ 774.02 | | | $ 867.80 | **$ 93.78** | **12.12%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | -$ 2.1180 | 250 | -$ 529.50 | -$ 2.4348 | 250 | -$ 608.70 | -$ 79.20 | 14.96% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| GA Variance Account Disposition Rate Rider (Non-RPP) | per kW | $ 0.8435 | 250 | $ 210.88 | $ 1.8722 | 250 | $ 468.05 | $ 257.18 | 121.96% |
| Low Voltage Service Charge | per kW | $ 0.4442 | 250 | $ 111.05 | $ 0.5215 | 250 | $ 130.38 | $ 19.33 | 17.40% |
| Smart Meter Entity Charge | Monthly | | | | | | | | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 566.45** | | | **$ 857.53** | **$ 291.08** | **51.39%** |
| RTSR - Network | per kW | $ 2.0363 | 250 | $ 509.08 | $ 2.4666 | 250 | $ 616.65 | $ 107.57 | 21.13% |
| RTSR - Line and Transformation Connection | per kW | $ 1.1349 | 250 | $ 283.73 | $ 1.2764 | 250 | $ 319.09 | $ 35.37 | 12.47% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 1,359.25** | | | **$ 1,793.26** | **$ 434.02** | **31.93%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 92,450 | $ 406.78 | $ 0.0044 | 92,106 | $ 405.27 | -$ 1.51 | -0.37% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0012 | 92,450 | $ 110.94 | $ 0.0012 | 92,106 | $ 110.53 | -$ 0.41 | -0.37% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | per kWh | $ 0.0070 | 86,000 | $ 602.00 | $ 0.0070 | 86,000 | $ 602.00 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0750 | 750 | $ 56.25 | $ 0.0750 | 750 | $ 56.25 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.0880 | 91,700 | $ 8,069.60 | $ 0.0880 | 91,356 | $ 8,039.33 | -$ 30.27 | -0.38% |
| Energy - Commodity COP | per kWh | $ 0.0807 | 92,450 | $ 7,459.79 | $ 0.0807 | 92,106 | $ 7,432.03 | -$ 27.76 | -0.37% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| **Total Bill on Commodity COP** | | | | **$ 10,605.07** | | | **$ 11,006.89** | **$ 401.82** | **3.79%** |
| HST | | 13% | | $ 1,378.66 | 13% | | $ 1,430.90 | $ 52.24 | 3.79% |
| **Total Bill** (including HST) | | | | $ 11,983.72 | | | $ 12,437.78 | $ 454.06 | 3.79% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 1,198.37 | | | -$ 1,243.78 | -$ 45.41 | 3.79% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 10,785.35** | | | **$ 11,194.00** | **$ 408.65** | **3.79%** |

**Loss Factor (%)** 7.5000% | 7.10%

# Appendix 2-W
## Bill Impacts

**Customer Class:** **Unmetered Scattered Load**

**Consumption** 800 **kWh**

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | Proposed Rate ($) | Proposed Volume | Proposed Charge ($) | Impact $ Change | Impact % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ - | 1 | $ - | $ 0.46 | 1 | $ 0.46 | $ 0.46 | |
| Forgone Revenue Rider | Monthly | | 1 | $ - | -$ 1.1200 | 1 | -$ 1.12 | -$ 1.12 | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0177 | 800 | $ 14.16 | $ 0.0113 | 800 | $ 9.04 | -$ 5.12 | -36.16% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| **Sub-Total A** | | | | $ 14.16 | | | $ 8.38 | **-$ 5.78** | **-40.82%** |
| Deferral/Variance Account Disposition Rate Rider | per kWh | -$ 0.0046 | 800 | -$ 3.68 | -$ 0.0054 | 800 | -$ 4.32 | -$ 0.64 | 17.39% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| Low Voltage Service Charge | per kWh | $ 0.0011 | 800 | $ 0.88 | $ 0.0014 | 800 | $ 1.12 | $ 0.24 | 27.27% |
| Smart Meter Entity Charge | Monthly | | | | | | | | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 11.36** | | | **$ 5.18** | **-$ 6.18** | **-54.40%** |
| RTSR - Network | per kWh | $ 0.0051 | 860 | $ 4.39 | $ 0.0062 | 857 | $ 5.29 | $ 0.91 | 20.68% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0028 | 860 | $ 2.41 | $ 0.0031 | 857 | $ 2.70 | $ 0.29 | 12.05% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 18.15** | | | **$ 13.17** | **-$ 4.98** | **-27.45%** |
| Wholesale Market Service Charge (WMSC) | | $ 0.0044 | 860 | $ 3.78 | $ 0.0044 | 857 | $ 3.77 | -$ 0.01 | -0.37% |
| Rural and Remote Rate Protection (RRRP) | | $ 0.0012 | 860 | $ 1.03 | $ 0.0012 | 857 | $ 1.03 | -$ 0.00 | -0.37% |
| Standard Supply Service Charge | | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0070 | 800 | $ 5.60 | $ 0.0070 | 800 | $ 5.60 | $ - | 0.00% |
| Energy - RPP - Tier 1 | | $ 0.0750 | 750 | $ 56.25 | $ 0.0750 | 750 | $ 56.25 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.0880 | 110 | $ 9.68 | $ 0.0880 | 107 | $ 9.40 | -$ 0.28 | -2.91% |
| TOU - Off Peak | | $ 0.0650 | 550 | $ 35.78 | $ 0.0650 | 548 | $ 35.64 | -$ 0.13 | -0.37% |
| TOU - Mid Peak | | $ 0.1000 | 155 | $ 15.48 | $ 0.1000 | 154 | $ 15.42 | -$ 0.06 | -0.37% |
| TOU - On Peak | | $ 0.1170 | 155 | $ 18.11 | $ 0.1170 | 154 | $ 18.04 | -$ 0.07 | -0.37% |
| | | | | | | | | | |
| **Total Bill on RPP (before Taxes)** | | | | **$ 94.75** | | | **$ 89.47** | **-$ 5.28** | **-5.58%** |
| HST | | 13% | | $ 12.32 | 13% | | $ 11.63 | -$ 0.69 | -5.58% |
| **Total Bill** (including HST) | | | | $ 107.07 | | | $ 101.10 | -$ 5.97 | -5.58% |
| ***Ontario Clean Energy Benefit* [1]** | | | | -$ 10.71 | | | -$ 10.11 | $ 0.60 | -5.60% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 96.36** | | | **$ 90.99** | **-$ 5.37** | **-5.57%** |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 98.19** | | | **$ 92.93** | **-$ 5.26** | **-5.36%** |
| HST | | 13% | | $ 12.76 | 13% | | $ 12.08 | -$ 0.68 | -5.36% |
| **Total Bill** (including HST) | | | | $ 110.95 | | | $ 105.01 | -$ 5.94 | -5.36% |
| ***Ontario Clean Energy Benefit* [1]** | | | | -$ 11.10 | | | -$ 10.50 | $ 0.60 | -5.41% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 99.85** | | | **$ 94.51** | **-$ 5.34** | **-5.35%** |

**Loss Factor (%)** — Current: 7.5000% — Proposed: 7.10%

# Appendix 2-W
# Bill Impacts

**Customer Class:** **Streetlights**

**Consumption** 280 **kWh** **Consumption** 1 **KW**

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | Proposed Rate ($) | Proposed Volume | Proposed Charge ($) | Impact $ Change | Impact % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 3.1400 | 1 | $ 3.14 | $ 3.45 | 1 | $ 3.45 | $ 0.31 | 9.87% |
| Forgone Revenue Rider | Monthly | | 1 | $ - | $ 0.0600 | 1 | $ 0.06 | $ 0.06 | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 14.0054 | 1 | $ 14.01 | $ 14.3874 | 1 | $ 14.39 | $ 0.38 | 2.73% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| **Sub-Total A** | | | | $ 17.15 | | | $ 17.90 | **$ 0.75** | **4.39%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | -$ 2.2231 | 1 | -$ 2.22 | -$ 2.6672 | 1 | -$ 2.67 | -$ 0.44 | 19.98% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| GA Variance Account Disposition Rate Rider (Non-RPP) | per kWh | | 280 | $ - | $ 0.8216 | 1 | $ 0.82 | $ 0.82 | |
| Low Voltage Service Charge | per kW | $ 0.3434 | 1 | $ 0.34 | $ 0.4031 | 1 | $ 0.40 | $ 0.06 | 17.38% |
| Smart Meter Entity Charge | Monthly | | | | | | | | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 15.27** | | | **$ 16.45** | **$ 1.19** | **7.79%** |
| RTSR - Network | per kW | $ 1.5357 | 1 | $ 1.54 | $ 1.8602 | 1 | $ 1.86 | $ 0.32 | 21.13% |
| RTSR - Line and Transformation Connection | per kW | $ 0.8773 | 1 | $ 0.88 | $ 0.9867 | 1 | $ 0.99 | $ 0.11 | 12.47% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 17.68** | | | **$ 19.30** | **$ 1.62** | **9.18%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0044 | 301 | $ 1.32 | $ 0.0044 | 300 | $ 1.32 | -$ 0.00 | -0.37% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0012 | 301 | $ 0.36 | $ 0.0012 | 300 | $ 0.36 | -$ 0.00 | -0.37% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | per kWh | $ 0.0070 | 280 | $ 1.96 | $ 0.0070 | 280 | $ 1.96 | $ - | 0.00% |
| Energy - RPP - Tier 1 | per kWh | $ 0.0750 | | $ - | $ 0.0750 | | $ - | $ - | |
| Energy - RPP - Tier 2 | per kWh | $ 0.0880 | | $ - | $ 0.0880 | | $ - | $ - | |
| Energy - Commodity COP | per kWh | $ 0.0807 | 301 | $ 24.29 | $ 0.0807 | 300 | $ 24.20 | -$ 0.09 | -0.37% |
| | | | | $ - | | | $ - | $ - | |
| | | | | $ - | | | $ - | $ - | |
| **Total Bill on Commodity COP** | | | | **$ 45.86** | | | **$ 47.39** | **$ 1.53** | **3.33%** |
| HST | | 13% | | $ 5.96 | 13% | | $ 6.16 | $ 0.20 | 3.33% |
| **Total Bill** (including HST) | | | | $ 51.82 | | | $ 53.55 | $ 1.72 | 3.33% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 5.18 | | | -$ 5.35 | -$ 0.17 | 3.33% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 46.64** | | | **$ 48.19** | **$ 1.55** | **3.33%** |

**Loss Factor (%)** Current: 7.5000% Proposed: 7.10%

# 2013 Cost Allocation Model

## Sheet O1 Revenue to Cost Summary Worksheet - COLLUS 2013 - Final Run

**Instructions:**
**Please see the first tab in this workbook for detailed instructions**

### Class Revenue, Cost Analysis, and Return on Rate Base

| Rate Base Assets | | Total | 1<br>Residential | 2<br>General Service < 50 kW | 3<br>General Service 50 - 4,999 kW | 7<br>Street Lighting | 9<br>Unmetered Scattered Load |
|---|---|---|---|---|---|---|---|
| crev | Distribution Revenue at Existing Rates | $5,610,672 | $3,542,372 | $903,561 | $954,844 | $202,753 | $7,142 |
| mi | Miscellaneous Revenue (mi) | $480,405 | $320,982 | $103,611 | $38,860 | $16,661 | $291 |
| | | Miscellaneous Revenue Input equals Output | | | | | |
| | **Total Revenue at Existing Rates** | **$6,091,077** | **$3,863,354** | **$1,007,171** | **$993,704** | **$219,414** | **$7,433** |
| | Factor required to recover deficiency (1 + D) | 1.1193 | | | | | |
| | Distribution Revenue at Status Quo Rates | $6,280,048 | $3,964,991 | $1,011,359 | $1,068,761 | $226,943 | $7,994 |
| | Miscellaneous Revenue (mi) | $480,405 | $320,982 | $103,611 | $38,860 | $16,661 | $291 |
| | **Total Revenue at Status Quo Rates** | **$6,760,453** | **$4,285,974** | **$1,114,970** | **$1,107,620** | **$243,603** | **$8,285** |
| | **Expenses** | | | | | | |
| di | Distribution Costs (di) | $1,925,300 | $1,174,667 | $272,724 | $392,785 | $83,589 | $1,535 |
| cu | Customer Related Costs (cu) | $1,261,562 | $896,353 | $315,571 | $48,433 | $1,006 | $198 |
| ad | General and Administration (ad) | $1,398,298 | $905,855 | $257,153 | $196,959 | $37,560 | $770 |
| dep | Depreciation and Amortization (dep) | $940,212 | $542,528 | $157,873 | $206,613 | $32,495 | $703 |
| INPUT | PILs (INPUT) | $67,958 | $37,881 | $10,793 | $17,048 | $2,183 | $53 |
| INT | Interest | $461,552 | $257,276 | $73,304 | $115,785 | $14,824 | $363 |
| | **Total Expenses** | **$6,054,882** | **$3,814,560** | **$1,087,418** | **$977,624** | **$171,657** | **$3,623** |
| | **Direct Allocation** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| NI | Allocated Net Income (NI) | $705,571 | $393,296 | $112,059 | $177,000 | $22,662 | $555 |
| | **Revenue Requirement (includes NI)** | $6,760,453 | $4,207,856 | $1,199,476 | $1,154,624 | $194,319 | $4,177 |
| | | Revenue Requirement Input equals Output | | | | | |
| | **Total Rate Base** | **$19,642,858** | **$10,487,745** | **$3,148,292** | **$5,434,388** | **$554,752** | **$17,681** |
| | | Rate Base Input equals Output | | | | | |
| | **Equity Component of Rate Base** | **$7,857,143** | **$4,195,098** | **$1,259,317** | **$2,173,755** | **$221,901** | **$7,072** |
| | **Net Income on Allocated Assets** | **$705,571** | **$471,414** | **$27,552** | **$129,996** | **$71,946** | **$4,663** |
| | **Net Income on Direct Allocation Assets** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| | **Net Income** | **$705,571** | **$471,414** | **$27,552** | **$129,996** | **$71,946** | **$4,663** |
| | **RATIOS ANALYSIS** | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | **100.00%** | **101.86%** | **92.95%** | **95.93%** | **125.36%** | **198.34%** |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | **($669,376)** | ($344,502) | ($192,305) | ($160,920) | $25,095 | $3,256 |
| | | Deficiency Input equals Output | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | **$0** | $78,118 | ($84,507) | ($47,004) | $49,285 | $4,108 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 8.98% | 11.24% | 2.19% | 5.98% | 32.42% | 65.93% |

# Revenue Requirement Workform

**Version** 3.00

| | |
|---|---|
| **Utility Name** | COLLUS Power Corp. |
| **Service Territory** | |
| **Assigned EB Number** | EB-2012-0116 |
| **Name and Title** | Cindy Shuttleworth, CFO |
| **Phone Number** | 705-445-1800 ext 2270 |
| **Email Address** | cshuttleworth@collus.com |



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

# Revenue Requirement Workform



**Notes:**

**(1)** Pale green cells represent inputs

**(2)** Pale green boxes at the bottom of each page are for additional notes

**(3)** Pale yellow cells represent drop-down lists

**(4)** ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

**(5)** ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

# Revenue Requirement Workform

## Data Input (1)

| | | Initial Application | (2) | Adjustments | Settlement Agreement | (6) | Adjustments | Per Board Decision | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Rate Base** | | | | | | | | |
| | Gross Fixed Assets (average) | $32,024,061 | | ($149,000) | $ 31,875,061 | | | $31,875,061 | |
| | Accumulated Depreciation (average) | ($16,324,684) | (5) | $5,450 | ($16,319,234) | | | ($16,319,234) | |
| | Allowance for Working Capital: | | | | | | | | |
| | Controllable Expenses | $4,755,160 | | ($314,000) | $ 4,441,160 | | | $4,441,160 | |
| | Cost of Power | $30,273,460 | | ($656,050) | $ 29,617,410 | | | $29,617,410 | |
| | Working Capital Rate (%) | 13.00% | (9) | | 12.00% | (9) | | 12.00% | (9) |
| 2 | **Utility Income** | | | | | | | | |
| | Operating Revenues: | | | | | | | | |
| | Distribution Revenue at Current Rates | $5,581,495 | | $29,176 | $5,610,672 | | $0 | $5,610,672 | |
| | Distribution Revenue at Proposed Rates | $6,515,797 | | ($235,749) | $6,280,048 | | $0 | $6,280,048 | |
| | Other Revenue: | | | | | | | | |
| | Specific Service Charges | $204,000 | | ($40,000) | $164,000 | | $0 | $164,000 | |
| | Late Payment Charges | $84,000 | | $0 | $84,000 | | $0 | $84,000 | |
| | Other Distribution Revenue | $123,600 | | $50,205 | $173,805 | | $0 | $173,805 | |
| | Other Income and Deductions | $54,000 | | $4,600 | $58,600 | | $0 | $58,600 | |
| | Total Revenue Offsets | $465,600 | (7) | $14,805 | $480,405 | | $0 | $480,405 | |
| | Operating Expenses: | | | | | | | | |
| | OM+A Expenses | $4,755,160 | | ($170,000) | $ 4,585,160 | | | $4,585,160 | |
| | Depreciation/Amortization | $948,979 | (10) | ($8,767) | $ 940,212 | | | $940,212 | |
| | Property taxes | | | | | | | | |
| | Other expenses | | | | | | | | |
| 3 | **Taxes/PILs** | | | | | | | | |
| | Taxable Income: | | | | | | | | |
| | Adjustments required to arrive at taxable income | ($324,750) | (3) | | ($335,090) | | | ($335,090) | |
| | Utility Income Taxes and Rates: | | | | | | | | |
| | Income taxes (not grossed up) | $62,425 | | | $57,425 | | | $57,425 | |
| | Income taxes (grossed up) | $73,876 | | | $67,959 | | | $67,959 | |
| | Federal tax (%) | 4.50% | | | 4.50% | | | 4.50% | |
| | Provincial tax (%) | 11.00% | | | 11.00% | | | 11.00% | |
| | Income Tax Credits | $ - | | | $ - | | | $ - | |
| 4 | **Capitalization/Cost of Capital** | | | | | | | | |
| | Capital Structure: | | | | | | | | |
| | Long-term debt Capitalization Ratio (%) | 56.0% | | | 56.0% | | | 56.0% | |
| | Short-term debt Capitalization Ratio (%) | 4.0% | (8) | | 4.0% | (8) | | 4.0% | (8) |
| | Common Equity Capitalization Ratio (%) | 40.0% | | | 40.0% | | | 40.0% | |
| | Prefered Shares Capitalization Ratio (%) | | | | | | | | |
| | | 100.0% | | | 100.0% | | | 100.0% | |
| | Cost of Capital | | | | | | | | |
| | Long-term debt Cost Rate (%) | 4.05% | | | 4.05% | | | 4.05% | |
| | Short-term debt Cost Rate (%) | 2.07% | | | 2.07% | | | 2.07% | |
| | Common Equity Cost Rate (%) | 8.98% | | | 8.98% | | | 8.98% | |
| | Prefered Shares Cost Rate (%) | | | | | | | | |
| | Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($) | $ - | (11) | | | (11) | | | (11) |

**Notes:**

**General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

**(1)** All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

**(2)** Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

**(3)** Net of addbacks and deductions to arrive at taxable income.

**(4)** Average of Gross Fixed Assets at beginning and end of the Test Year

**(5)** Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

**(6)** Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

**(7)** Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

**(8)** 4.0% unless an Applicant has proposed or been approved for another amount.

**(9)** Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

**(10)** Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

**(11)** Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

Per Board Decision represents the Settlement Agreement if accepted by the Board

# Revenue Requirement Workform

## Rate Base and Working Capital

### Rate Base

| Line No. | Particulars | | Initial Application | Adjustments | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 1 | Gross Fixed Assets (average) | (3) | $32,024,061 | ($149,000) | $31,875,061 | $ - | $31,875,061 |
| 2 | Accumulated Depreciation (average) | (3) | ($16,324,684) | $5,450 | ($16,319,234) | $ - | ($16,319,234) |
| 3 | Net Fixed Assets (average) | (3) | $15,699,377 | ($143,550) | $15,555,827 | $ - | $15,555,827 |
| 4 | Allowance for Working Capital | (1) | $4,553,721 | ($466,692) | $4,087,028 | $ - | $4,087,028 |
| 5 | **Total Rate Base** | | $20,253,098 | ($610,242) | $19,642,855 | $ - | $19,642,855 |

### Allowance for Working Capital - Derivation

(1)

| Line No. | Particulars | | Initial Application | Adjustments | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|---|
| 6 | Controllable Expenses | | $4,755,160 | ($314,000) | $4,441,160 | $ - | $4,441,160 |
| 7 | Cost of Power | | $30,273,460 | ($656,050) | $29,617,410 | $ - | $29,617,410 |
| 8 | Working Capital Base | | $35,028,620 | ($970,050) | $34,058,570 | $ - | $34,058,570 |
| 9 | Working Capital Rate % | (2) | 13.00% | -1.00% | 12.00% | 0.00% | 12.00% |
| 10 | Working Capital Allowance | | $4,553,721 | ($466,692) | $4,087,028 | $ - | $4,087,028 |

**Notes**

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Per Board Decision represents the Settlement Agreement if accepted by the Board

# Revenue Requirement Workform

## Utility Income

| Line No. | Particulars | | Initial Application | Adjustments | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|---|
| | **Operating Revenues:** | | | | | | |
| 1 | Distribution Revenue (at Proposed Rates) | | $6,515,797 | ($235,749) | $6,280,048 | $ - | $6,280,048 |
| 2 | Other Revenue | (1) | $465,600 | $14,805 | $480,405 | $ - | $480,405 |
| 3 | Total Operating Revenues | | $6,981,397 | ($220,944) | $6,760,453 | $ - | $6,760,453 |
| | **Operating Expenses:** | | | | | | |
| 4 | OM+A Expenses | | $4,755,160 | ($170,000) | $4,585,160 | $ - | $4,585,160 |
| 5 | Depreciation/Amortization | | $948,979 | ($8,767) | $940,212 | $ - | $940,212 |
| 6 | Property taxes | | $ - | $ - | | $ - | |
| 7 | Capital taxes | | $ - | $ - | $ - | $ - | $ - |
| 8 | Other expense | | $ - | $ - | | $ - | |
| 9 | Subtotal (lines 4 to 8) | | $5,704,139 | ($178,767) | $5,525,372 | $ - | $5,525,372 |
| 10 | Deemed Interest Expense | | $475,891 | ($14,339) | $461,552 | $ - | $461,552 |
| 11 | Total Expenses (lines 9 to 10) | | $6,180,030 | ($193,106) | $5,986,924 | $ - | $5,986,924 |
| 12 | Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS | | $ - | $ - | $ - | $ - | $ - |
| 13 | **Utility income before income taxes** | | $801,367 | ($27,838) | $773,530 | $ - | $773,530 |
| 14 | Income taxes (grossed-up) | | $73,876 | ($5,917) | $67,959 | $ - | $67,959 |
| 15 | **Utility net income** | | $727,492 | ($21,921) | $705,571 | $ - | $705,571 |

**Notes**

### Other Revenues / Revenue Offsets

| Note | Particulars | Initial Application | Adjustments | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|
| (1) | Specific Service Charges | $204,000 | ($40,000) | $164,000 | $ - | $164,000 |
| | Late Payment Charges | $84,000 | $ - | $84,000 | $ - | $84,000 |
| | Other Distribution Revenue | $123,600 | $50,205 | $173,805 | $ - | $173,805 |
| | Other Income and Deductions | $54,000 | $4,600 | $58,600 | $ - | $58,600 |
| | Total Revenue Offsets | $465,600 | $14,805 | $480,405 | $ - | $480,405 |

Per Board Decision represents the Settlement Agreement if accepted by the Board

# Revenue Requirement Workform

## Taxes/PILs

| Line No. | Particulars | Application | Settlement Agreement | Per Board Decision |
|---|---|---|---|---|
| | **Determination of Taxable Income** | | | |
| 1 | Utility net income before taxes | $727,491 | $705,571 | $705,571 |
| 2 | Adjustments required to arrive at taxable utility income | ($324,750) | ($335,090) | ($335,090) |
| 3 | Taxable income | $402,741 | $370,481 | $370,482 |
| | **Calculation of Utility income Taxes** | | | |
| 4 | Income taxes | $62,425 | $57,425 | $57,425 |
| 6 | Total taxes | $62,425 | $57,425 | $57,425 |
| 7 | Gross-up of Income Taxes | $11,451 | $10,534 | $10,534 |
| 8 | Grossed-up Income Taxes | $73,876 | $67,959 | $67,959 |
| 9 | PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | $73,876 | $67,959 | $67,959 |
| 10 | Other tax Credits | $ - | $ - | $ - |
| | **Tax Rates** | | | |
| 11 | Federal tax (%) | 4.50% | 4.50% | 4.50% |
| 12 | Provincial tax (%) | 11.00% | 11.00% | 11.00% |
| 13 | Total tax rate (%) | 15.50% | 15.50% | 15.50% |

**Notes**

Per Board Decision represents the Settlement Agreement if accepted by the Board

# Revenue Requirement Workform

## Capitalization/Cost of Capital

| Line No. | Particulars | Capitalization Ratio | | Cost Rate | Return |
|---|---|---|---|---|---|
| | | **Initial Application** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 56.00% | $11,341,735 | 4.05% | $459,121 |
| 2 | Short-term Debt | 4.00% | $810,124 | 2.07% | $16,770 |
| 3 | **Total Debt** | 60.00% | $12,151,859 | 3.92% | $475,891 |
| | **Equity** | | | | |
| 4 | Common Equity | 40.00% | $8,101,239 | 8.98% | $727,491 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 40.00% | $8,101,239 | 8.98% | $727,491 |
| 7 | **Total** | 100.00% | $20,253,098 | 5.94% | $1,203,382 |
| | | **Settlement Agreement** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 1 | Long-term Debt | 56.00% | $10,999,999 | 4.05% | $445,288 |
| 2 | Short-term Debt | 4.00% | $785,714 | 2.07% | $16,264 |
| 3 | **Total Debt** | 60.00% | $11,785,713 | 3.92% | $461,552 |
| | **Equity** | | | | |
| 4 | Common Equity | 40.00% | $7,857,142 | 8.98% | $705,571 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 6 | **Total Equity** | 40.00% | $7,857,142 | 8.98% | $705,571 |
| 7 | **Total** | 100.00% | $19,642,855 | 5.94% | $1,167,123 |
| | | **Per Board Decision** | | | |
| | | (%) | ($) | (%) | ($) |
| | **Debt** | | | | |
| 8 | Long-term Debt | 56.00% | $10,999,999 | 4.05% | $445,288 |
| 9 | Short-term Debt | 4.00% | $785,714 | 2.07% | $16,264 |
| 10 | **Total Debt** | 60.00% | $11,785,713 | 3.92% | $461,552 |
| | **Equity** | | | | |
| 11 | Common Equity | 40.00% | $7,857,142 | 8.98% | $705,571 |
| 12 | Preferred Shares | 0.00% | $ - | 0.00% | $ - |
| 13 | **Total Equity** | 40.00% | $7,857,142 | 8.98% | $705,571 |
| 14 | **Total** | 100.00% | $19,642,855 | 5.94% | $1,167,123 |

**Notes**

**(1)** Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Per Board Decision represents the Settlement Agreement if accepted by the Board

# Revenue Requirement Workform

## Revenue Deficiency/Sufficiency

| Line No. | Particulars | Initial Application: At Current Approved Rates | Initial Application: At Proposed Rates | Settlement Agreement: At Current Approved Rates | Settlement Agreement: At Proposed Rates | Per Board Decision: At Current Approved Rates | Per Board Decision: At Proposed Rates |
|---|---|---|---|---|---|---|---|
| 1 | Revenue Deficiency from Below | | $934,301 | | $669,377 | | $669,377 |
| 2 | Distribution Revenue | $5,581,495 | $5,581,496 | $5,610,672 | $5,610,672 | $5,610,672 | $5,610,672 |
| 3 | Other Operating Revenue Offsets - net | $465,600 | $465,600 | $480,405 | $480,405 | $480,405 | $480,405 |
| 4 | **Total Revenue** | $6,047,095 | $6,981,397 | $6,091,077 | $6,760,453 | $6,091,077 | $6,760,453 |
| 5 | Operating Expenses | $5,704,139 | $5,704,139 | $5,525,372 | $5,525,372 | $5,525,372 | $5,525,372 |
| 6 | Deemed Interest Expense | $475,891 | $475,891 | $461,552 | $461,552 | $461,552 | $461,552 |
| 7 | Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS | $ - **(2)** | $ - | $ - **(2)** | $ - | $ - **(2)** | $ - |
| 8 | **Total Cost and Expenses** | $6,180,030 | $6,180,030 | $5,986,924 | $5,986,924 | $5,986,924 | $5,986,924 |
| 9 | **Utility Income Before Income Taxes** | ($132,934) | $801,367 | $104,153 | $773,530 | $104,153 | $773,530 |
| 10 | Tax Adjustments to Accounting Income per 2013 PILs model | ($324,750) | ($324,750) | ($335,090) | ($335,090) | ($335,090) | ($335,090) |
| 11 | **Taxable Income** | ($457,684) | $476,617 | ($230,937) | $438,440 | ($230,937) | $438,440 |
| 12 | Income Tax Rate | 15.50% | 15.50% | 15.50% | 15.50% | 15.50% | 15.50% |
| 13 | **Income Tax on Taxable Income** | ($70,941) | $73,876 | ($35,795) | $67,958 | ($35,795) | $67,958 |
| 14 | **Income Tax Credits** | $ - | $ - | $ - | $ - | $ - | $ - |
| 15 | **Utility Net Income** | ($61,993) | $727,492 | $139,948 | $705,571 | $139,948 | $705,571 |
| 16 | **Utility Rate Base** | $20,253,098 | $20,253,098 | $19,642,855 | $19,642,855 | $19,642,855 | $19,642,855 |
| 17 | Deemed Equity Portion of Rate Base | $8,101,239 | $8,101,239 | $7,857,142 | $7,857,142 | $7,857,142 | $7,857,142 |
| 18 | Income/(Equity Portion of Rate Base) | -0.77% | 8.98% | 1.78% | 8.98% | 1.78% | 8.98% |
| 19 | Target Return - Equity on Rate Base | 8.98% | 8.98% | 8.98% | 8.98% | 8.98% | 8.98% |
| 20 | Deficiency/Sufficiency in Return on Equity | -9.75% | 0.00% | -7.20% | 0.00% | -7.20% | 0.00% |
| 21 | Indicated Rate of Return | 2.04% | 5.94% | 3.06% | 5.94% | 3.06% | 5.94% |
| 22 | Requested Rate of Return on Rate Base | 5.94% | 5.94% | 5.94% | 5.94% | 5.94% | 5.94% |
| 23 | Deficiency/Sufficiency in Rate of Return | -3.90% | 0.00% | -2.88% | 0.00% | -2.88% | 0.00% |
| 24 | Target Return on Equity | $727,491 | $727,491 | $705,571 | $705,571 | $705,571 | $705,571 |
| 25 | Revenue Deficiency/(Sufficiency) | $789,485 | $0 | $565,623 | ($0) | $565,623 | ($0) |
| 26 | **Gross Revenue Deficiency/(Sufficiency)** | $934,301 **(1)** | | $669,377 **(1)** | | $669,377 **(1)** | |

**Notes:**

**(1)** Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

**(2)** Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

Per Board Decision represents the Settlement Agreement if accepted by the Board

# Revenue Requirement Workform

## Revenue Requirement

| Line No. | Particulars | Application | Settlement Agreement | Per Board Decision |
|---|---|---|---|---|
| 1 | OM&A Expenses | $4,755,160 | $4,585,160 | $4,585,160 |
| 2 | Amortization/Depreciation | $948,979 | $940,212 | $940,212 |
| 3 | Property Taxes | $ - | | |
| 5 | Income Taxes (Grossed up) | $73,876 | $67,959 | $67,959 |
| 6 | Other Expenses | $ - | | |
| 7 | Return | | | |
| | Deemed Interest Expense | $475,891 | $461,552 | $461,552 |
| | Return on Deemed Equity | $727,491 | $705,571 | $705,571 |
| | Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS | $ - | $ - | $ - |
| 8 | **Service Revenue Requirement (before Revenues)** | $6,981,397 | $6,760,454 | $6,760,454 |
| 9 | Revenue Offsets | $465,600 | $480,405 | $480,405 |
| 10 | **Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)** | $6,515,797 | $6,280,049 | $6,280,049 |
| 11 | Distribution revenue | $6,515,797 | $6,280,048 | $6,280,048 |
| 12 | Other revenue | $465,600 | $480,405 | $480,405 |
| 13 | **Total revenue** | $6,981,397 | $6,760,453 | $6,760,453 |
| 14 | **Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)** | $0 **(1)** | ($0) **(1)** | ($0) **(1)** |

**Notes**

**(1)** Line 11 - Line 8

Per Board Decision represents the Settlement Agreement if accepted by the Board

## Table L-1: Class Revenue Share based on Current Rates and 2013 Billing Determinants

| | 2013 Test Year Forecast | | | Current Rates | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Class** | **Customer count** | **kWhs** | **kWs** | **Fixed Rate** | **Variable Rate** | **Fixed Revenue** | **Variable Revenue** | **Adjustment[1]** | **Total Revenue** |
| Residential | *14,233* | 117,956,589 | | $ 9.00 | $ 0.0170 | $ 1,537,147 | $ 2,005,262 | | **$ 3,542,409** |
| GS<50 | *1,717* | 47,173,865 | | $ 17.98 | $ 0.0113 | $ 370,456 | $ 533,065 | | **$ 903,521** |
| GS>50 | *117* | 116,404,810 | 342,409 | $ 114.02 | $ 2.6400 | $ 160,082 | $ 903,960 | $ (109,200) | **$ 954,842** |
| USL | *30* | 403,504 | | $ - | $ 0.0177 | $ - | $ 7,142 | | **$ 7,142** |
| Street Lighting | *3,045* | 2,165,737 | 6,285 | $ 3.14 | $ 14.0054 | $ 114,734 | $ 88,024 | | **$ 202,758** |
| **Total** | ***19,142*** | **284,104,505** | **348,694** | | | **$ 2,182,420** | **$ 3,537,452** | **$ (109,200)** | **$ 5,610,672** |

NOTE 1:

Adjustment of $(109,200) consists of:

1. Adjustment for Transformer Ownership Allowance - $(120,000)
2. Adjustment for Revenue for "replacement" customer (as per Settlement Agreement) - $10,800.

# Appendix 2-V
## Revenue Reconciliation

| | | Number of Customers/ Connections | | | Test Year Consumption | | Proposed Rates | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | Customers/ Connections | Start of Test Year | End of Test Year | Average | kWh | kW | Monthly Service Charge | Volumetric kWh | Volumetric kW | Revenues at Proposed Rates | Service Revenue Requirement | Transformer Allowance Credit | Total | Difference |
| Residential | Customers | 14,082 | 14,383 | 14,233 | 117,956,589 | | $ 9.88 | $ 0.0193 | | **$ 3,964,991** | $ 3,964,991 | | **$ 3,964,991** | $0 |
| GS < 50 kW | Customers | 1,705 | 1,729 | 1,717 | 47,173,865 | | $ 19.74 | $ 0.0131 | | **$ 1,024,701** | $ 1,025,094 | | **$ 1,025,094** | ($393) |
| GS > 50 to 4,999 kW | Customers | 117 | 117 | 117 | | 342,409 | $ 94.34 | | $ 3.0850 | **$ 1,188,785** | $ 1,068,761 | $ 120,000 | **$ 1,188,761** | $25 |
| Large Use | Customers | - | - | - | | - | $ - | | $ - | **$ -** | $ - | $ - | **$ -** | $0 |
| Streetlighting | Connections | 3,026 | 3,063 | 3,045 | | 6,285 | $ 3.45 | | $ 14.3874 | **$ 216,467** | $ 216,481 | | **$ 216,481** | ($14) |
| Sentinel Lighting | Connections | - | - | - | | - | $ - | | $ - | **$ -** | $ - | | **$ -** | $0 |
| Unmetered Scattered Load | Customers | 30 | 30 | 30 | 403,504 | | $ 0.46 | $ 0.0113 | | **$ 4,725** | $ 4,721 | | **$ 4,721** | $4 |
| **Total** | | | | | | | | | | **$ 6,399,669** | **$ 6,280,048** | **$ 120,000** | **$ 6,400,048** | **($378)** |

**Note**

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement
2 The Service Revenue Requirement was calculated without the Transformer Ownership Allowance cost which is converted to a rate adder and added to the GS>50 kW class that receives the allowance.