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October 23, 2013

Delivered by RESS and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

**Re: EB-2012-0109 – Brantford Power Inc.
Application to the Ontario Energy Board for Electricity Distribution Rates and Charges effective November 1, 2013**

We are counsel to Brantford Power Inc. ("**BPI**") with respect to the above-captioned matter. Please find enclosed BPI's interrogatory responses in respect of the above noted matter, which is being filed pursuant to the Board's correspondence dated October 22, 2013 granting BPI a two (2) day extension to the deadline for BPI to file its written interrogatory responses as set out in Procedural Order No. 1 and Procedural Order No. 2.

Confidentiality Request

Pursuant to Rule 10.01 of the Board's *Rules of Practice and Procedure*, for the reasons described below BPI respectfully requests that portions of the following three (3) interrogatory responses be held in confidence by the Board:

1. 4.0 Staff-19(a);
2. 4.0 Staff-20; and
3. 5.0 SEC-18.

4.0 Staff 19(a)

Board Staff asked in interrogatory 4.0 Staff-19(a):

> "BPI has included a cost driver in 2012 of $217k for amounts owed in relation to a retirement. a) Please explain the components of this retirement amount."

The amount relates to retirement payment(s) to one or more identifiable individual(s).

Under the *Freedom of Information and Protection of Privacy Act* ("***FIPPA***"), personal information means recorded information about an identifiable individual, including, among other things, information relating to financial transactions in which the individual has been involved.

Section 4.3.1 of the Board's *Practice Direction on Confidential Filings* provides:

> "Subject to limited exceptions, the Board is prohibited from releasing personal information, as that phrase is defined in FIPPA. When a person files a document or record that contains the personal information of another person who is not a party to the proceeding, the person filing the document or record must file two versions of the document or record in accordance with Rule 9A.01 of the Board's Rules of Practice and Procedure. As indicated in Rule 9A.02, the confidential, un-redacted version of the document or record will be held in confidence and neither that version of the document or record nor the personal information contained in it will be placed on the public record or provided to any other party, including a person from whom the Board has accepted a Declaration and Undertaking under section 6.1, unless the Board determines that the information is not personal information or that the disclosure of the personal information would be in accordance with the requirements of FIPPA."

A confidential, un-redacted version of this interrogatory response containing all of the information for which confidentiality is requested has been filed with the Board. In addition, a non-confidential, redacted version of the interrogatory response with the information that is the subject of this confidentiality request deleted has been filed together with the balance of BPI's interrogatory responses.

4.0 Staff-20

Board Staff asked in interrogatory 4.0 Staff-20 for a revised Appendix 2-K that removes all estimates of services provided and only includes BPI employees for the years 2008 actual to 2013 test year. Board Staff requested that BPI ensure that salary, wages, benefits and overtime amounts reflect only the amounts paid to BPI employees, and do not reflect amounts paid to service providers. Finally, Board Staff requested in a separate table average base wages, overtime, incentive pay and benefits for 2012 on both a pre-transfer and post-transfer basis, using the same FTEE categories contained in Appendix 2-K.

As evidenced in the non-confidential redacted version of Appendix 2-K filed in response to this interrogatory - for the years 2008, 2009, 2010 and 2011, BPI had a single employee. Not surprisingly, BPI also only had a single employee pre-transfer in 2012.

Consequently, for 2008, 2009, 2010, 2011, and pre-transfer in 2012 the information about salary and wages, benefits, accrued pension and post-retirement benefits and total compensation all relate to a single identifiable individual and constitutes personal information within the meaning of *FIPPA*. As a result, Section 4.3.1 of the Board's *Practice Direction on Confidential Filings* applies to this information.

A confidential, un-redacted version of this interrogatory response containing all of the information for which confidentiality is requested has been filed with the Board. In addition, a non-confidential, redacted version of the interrogatory response with the information that is the subject of this confidentiality request redacted has been filed together with the balance of BPI's interrogatory responses.

5.0 SEC-18

SEC asked in interrogatory 5.0 SEC-18 to provide all outstanding debt instruments not already provided in evidence.

This IR was limited in scope to the Infrastructure Ontario and RBC debt instruments because the City note is already on the evidentiary record. In compiling a response to this interrogatory, BPI was legally required pursuant to existing confidentiality arrangements to seek the consent of its third party lenders to file the relevant agreements. BPI requested such consent from Infrastructure Ontario, which has consented to the disclosure of the relevant IO debt instrument on a non-confidential basis.

BPI also requested the consent of its commercial lender, RBC. We have enclosed as Appendix "A" a letter from RBC setting out its response to this request. In light of this letter, at the request of RBC and for the reasons set out in RBC's letter and the reasons that follow, BPI is requesting that the entire RBC loan agreement be held in confidence by the Board.

In Appendix B of the *Practice Direction on Confidential Filings* the Board provides an illustrative list of the types of information previously assessed or maintained by the Board as confidential. The list includes "third party information as described in Section 17(1) of FIPPA, including vendor pricing information."

Section 17(1) of FIPPA provides:

> A head shall refuse to disclose a record that reveals a trade secret or scientific, technical, commercial, financial or labour relations information, supplied in confidence implicitly or explicitly, where the disclosure could reasonably be expected to,
>
> (a) prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of a person, group of persons, or organization;
>
> (b) result in similar information no longer being supplied to the institution where it is in the public interest that similar information continue to be so supplied;
>
> (c) result in undue loss or gain to any person, group, committee or financial institution or agency; or
>
> (d) reveal information supplied to or the report of a conciliation officer, mediator, labour relations officer or other person appointed to resolve a labour relations dispute.

The reasons RBC objects to the public disclosure of the loan agreement, as set out in the Appendix "A" letter, include the following:

> "(a) disclosure of the Loan Agreement publicly would negatively impact negotiations between RBC and other similar clients who may request similar terms and pricing;

(b) RBC does not want pricing disclosed to competitors;
(c) the Loan Agreement contains references to the names of third parties who have not consented to the public disclosure of their private information;
(d) the Loan Agreement contains certain standard clauses which RBC has developed and which are unique to RBC which RBC does not want competitors to have access to;
(e) the Loan Agreement contains certain proprietary information; and
(f) the Loan Agreement contains certain aspects of RBC’s lending model which RBC does not want competitors to have access to.”

Based on the RBC letter, BPI submits that the loan agreement reveals proprietary, commercial and financial information that was supplied in confidence to BPI and the public disclosure of the loan agreement could reasonably be expected to prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of RBC; result in similar information no longer being supplied to BPI where it is in the public interest that similar information continue to be so supplied; and result in undue loss to RBC and gain to RBC’s competitors.

A confidential, un-redacted version of the RBC loan agreement containing all of the information for which confidentiality is requested has been filed with the Board on coloured paper. In addition, a non-confidential, version of the interrogatory response with the RBC loan agreement that is the subject of this confidentiality request removed has been filed together with the balance of BPI’s interrogatory responses.

Should you have any questions or require further information, please do not hesitate to contact me.

Yours Truly,

BORDEN LADNER GERVAIS LLP

Original Signed by John A.D. Vellone

John A.D. Vellone

cc. Paul Kwasnik, Brantford Power Inc.
Heather Wyatt, Brantford Power Inc.
Parties of record in EB-2012-0109

TOR01: 5369255: v2

Borden Ladner Gervais

Appendix "A"
RBC Letter

Please see attached.

RBC Royal Bank®

Chris Hiebert
Regional Director
Public Sector – South Western Ontario

RBC Royal Bank
Commercial Financial Services
3405 Harvester Road, Suite 201
Burlington, Ontario L7N 3N1

Tel: (905) 333-7226 Fax: (905) 333-7321

October 22, 2013

Brantford Power Inc.
84 Market Street
P.O. Box 308
Brantford, Ontario
N3T 5N8

Attention: Brian D'Amboise

Dear Brian:

Re: Rate Application by Brantford Power Inc. to the Ontario Energy Board (the "OEB"), Confidentiality Request for the entire Loan Agreement dated September 28, 2012 between RBC and Brantford Power Inc. (as amended, modified or restated from time to time, the "Loan Agreement")

Royal Bank of Canada ("RBC") understands that Brantford Power Inc. (the "Borrower") will be applying to the OEB for a rate increase and that as part of such application, the Borrower is required to file a copy of its Loan Agreement with the OEB.

RBC also understands that pursuant to Section 5.1 of the OEB's Practice Direction on Confidential filings (Revised October 13, 2011) (the "Direction"), the Borrower may request that all of a document be held confidential.

RBC hereby requests the Borrower to make a request for confidentiality of the entire Loan Agreement to the Board Secretary of the OEB.

The reasons why RBC would like the entire Loan Agreement to be kept confidential are as follows:

(a) disclosure of the Loan Agreement publicly would negatively impact negotiations between RBC and other similar clients who may request similar terms and pricing;
(b) RBC does not want pricing disclosed to competitors;
(c) the Loan Agreement contains references to the names of third parties who have not consented to the public disclosure of their private information;

(d) the Loan Agreement contains certain standard clauses which RBC has developed and which are unique to RBC which RBC does not want competitors to have access to;
(e) the Loan Agreement contains certain proprietary information; and
(f) the Loan Agreement contains certain aspects of RBC's lending model which RBC does not want competitors to have access to.

For the above reasons, the potential negative impact on RBC from the public disclosure of the Loan Agreement is greater than any possible benefit to Brantford Power in publicly disclosing it.

Since confidential treatment is being requested in relation to the entire document, please submit the document to the OEB on coloured paper as required pursuant to Section 5.1.4(b) of the Direction.

The Loan Agreement may be submitted to the OEB by the Borrower but RBC requests that the Loan Agreement not be filed publicly.

Yours truly,

EB-2012-0109

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15, as amended;

AND IN THE MATTER OF an Application by Brantford Power Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of November 1, 2013.

BRANTFORD POWER INC.

2013 ELECTRICITY DISTRIBUTION RATE APPLICATION
RESPONSES TO INTERROGATORIES
FILED: OCTOBER 23, 2013

Applicant: Brantford Power Inc.

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EB-2012-0109

BRANTFORD POWER INC.

2013 ELECTRICITY DISTRIBUTION RATE APPLICATION

RESPONSES TO INTERROGATORIES

INDEX

1	Responses to Interrogatories
Attachments	Reference:
A	1.0 SEC 1
B	1.0 Energy Probe-1
C	1.0 Energy Probe-5
D	1.0 Energy Probe-7a
E	1.0 Energy Probe-7b
F	1.0 HVAC-4
G	2.0 Energy Probe-14
H	2.0 SEC-8
I	3.0 Staff-11
J	3.0 Staff-13
K	4.0 Energy Probe-24
L	4.0 SEC-11
M	4.0 SEC-15
N	5.0 Energy Probe-26
O	5.0 SEC-18
P	8.0 Staff-30
Q	9.0 Staff-35
R	Chapter 2 Appendicies Revisions
S	1.0 Staff-1
T	1.0 Staff 2

General

1.0 Staff-1 – Responses to Updated Revenue Requirement Workform

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Upon completing responses to all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or any explanatory note.

Response: Please find attached an updated Revenue Requirement Work Form as Attachment S. The following table documents the adjustments made, with reference to the applicable interrogatories.

Reference	Item	Rate Base	Return on Rate Base	Regulated Rate of Return	Working Capital Base	Working Capital Allowance	Amortization	PILS	OM&A	Service Revenue Requirement	Base Revenue Requirement	Gross Revenue Deficiency
Application		**$78,748,369**	**$5,175,141**	**6.57%**	**$107,238,853**	**$13,941,051**	**$2,995,584**	**$477,851**	**$9,204,025**	**$17,864,600**	**$16,703,454**	**$ 1,409,559**
2-Energy Probe-8, 2-Energy Probe-9, 2-Energy Probe-13 b)	Update to 2012 Actuals	$77,775,365	$5,111,198	6.57%	$ 107,238,853	$13,941,051	$2,995,584	$481,958	$9,204,025	$17,804,764	$16,643,618	$ 1,349,722
	Change	$ (973,004)	$ (63,943)	0%	$ -	$ -	$ -	$ 4,107	$ -	$ (59,836)	$ (59,836)	$ (59,837)
2-Energy Probe-14	Correction to the Cost of Power Calculation	$ 77,671,375	$ 5,104,364	6.57%	$106,438,930	$13,837,061	$2,995,584	$480,771	$9,204,025	$17,796,743	$16,635,597	$ 1,341,701
	Change	$ (1,076,994)	$ (70,777)	0%	$ (799,923)	$ (103,990)	$ -	$ 2,919	$ -	$ (67,857)	$ (67,857)	$ (67,858)
9-Staff-36	Correction to Provincial Tax Rate	$ 77,671,375	$ 5,104,364	6.57%	$106,438,930	$13,837,061	$2,995,584	$484,139	$9,204,025	$17,800,112	$16,638,965	$ 1,345,070
	Change	$ (1,076,994)	$ (70,777)	0%	$ (799,923)	$ (103,990)	$ -	$ 6,288	$ -	$ (64,489)	$ (64,489)	$ (64,489)
3- Staff-11	Load Forecast: Updated Negative Impact	$77,391,058	$5,085,942	6.57%	$104,282,650	$13,556,745	$2,995,584	$480,909	$9,204,025	$17,778,460	$16,617,313	$ 1,521,105
		$ (1,357,311)	$ (89,199)	0%	$ (2,956,203)	$ (384,306)	$ -	$ 3,058	$ -	$ (86,141)	$ (86,141)	$ 111,547
4-Energy Probe-25	CCA Changes	$77,391,058	$5,085,942	6.57%	$104,282,650	$13,556,745	$2,995,584	$496,909	$9,204,025	$17,794,460	$16,633,314	$ 1,537,106
		$ (1,357,311)	$ (89,199)	0%	$ (2,956,203)	$ (384,306)	$ -	$ 19,058	$ -	$ (70,140)	$ (70,140)	$ 127,547
								$ -				
Interrogatories		**$ 77,391,058**	**$ 5,085,942**	**6.57%**	**$ 104,282,650**	**$ 13,556,745**	**$ 2,995,584**	**$ 496,909**	**$ 9,204,025**	**$ 17,794,460**	**$ 16,633,314**	**$ 1,537,106**

1.0 Staff-2 - Updated Cost Allocation Study

Upon completing responses to all interrogatories from Board staff and intervenors, please provide a corrected Cost Allocation study with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the Cost Allocation model. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or any explanatory note.

Response: Please find attached an updated Cost Allocation Study which incorporates the following adjustments as Attachment T.

Sheet I3- Trial Balance Data has been updated to correspond to the updates to 2012 Actuals in BPI's Trial Balance, as requested in 2-Energy Probe-8, 2-Energy Probe 9 and 2-Energy Probe 13 b). There was an additional update to the Cost of Power amounts, reflecting the new Load Forecast prepared for 3-Staf-11 and with a corrected Non-RPP cost in response to 2.0-Energy Probe-14,

Sheet I6.1- Revenue has been updated to match BPI's updated Load Forecast, which was provided in response to 3-Board Staff-11. As well, the Revenue Deficiency has been changed as a result of the already-mentioned Trial Balance and Load Forecast changes.

Sheet I8- Demand Data has also been amended to correspond with the Load Forecast from 3-Board Staff-11.

Please note that as a result of these updates, the Street Light Revenue- to – Cost ratio increased to 121%. During the Rate Design process used to generate the updated Bill Impacts for 1-Staff-3, BPI followed the same process described in Exhibit 7, Tab1, Schedule 2, page 5, but also shifted the Street Light ratio to the Board's target high Revenue-to Cost ratio of 120%, reallocating the minimal resultant change in revenue to the GS<50 class.

1.0 Staff-3 - Updated Appendix 2-W – Bill Impacts

Upon completing responses to all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption/demand levels (i.e. 800 kWh for Residential, 2,000 kWh for General Service Less Than 50 kW).

Response: These Bill Impacts include the following changes:

- Updated Rates for each class which reflect the changes resulting from the updated Trial Balance (including Cost of Power in response to 2-Energy Probe-14, LEAP Amounts and 2012 Actuals), as well as the updated Load Forecast resulting from 3-Staff-11.
- Updated Stranded Meter Recovery Rate Rider and Smart Meter Disposition Rate Rider, as calculated in response to the interrogatories 9 Staff 40 and 9 Staff-41.
- Updated Network and Line Retail Transmission Rates, in response to interrogatories Attachment P and 8.0 Staff-30.
- LRAM Rate Riders, LRAMVA Rate Rider, Deferral and Variance Account Rate Riders and Non-RPP Global Adjustment Rate Riders, all updated to reflect the new Load Forecast resulting from 3-Staff-11.

1.0 SEC-1

Please provide all documents and information that was provided to the Board of Directors, in approving this application and the Test Year budget.

Response: The report to the BPI Board of Directors seeking approval of the 2013 Test Year Budget is attached as Attachment A to this document.

BPI advises that while the BPI Board of Directors was provided with regular status updates on the progress of this application, the BPI Board of Directors did not specifically approve the application.

Exhibit 1 – Administrative Documents

1.0 Energy Probe-1

Ref: Exhibit 1, Tab 1, Schedule 2

The evidence indicates that the test year budget was approved by the BPI Board of Directors on January 24, 2013.

a) Have any changes been made to the test year budget since this approval?

Response: No changes have been made to the 2013 test year budget since the BPI Board's approval on January 24, 2013.

b) Has the Board of Directors seen any updates, comparison to budget, etc. since the approval was provided on January 24, 2013? If yes, please provide all material and presentations made to the Board of Directors subsequent to the January 24, 2013 approval.

Response: The BPI Board of Directors has received two updates reporting on the Interim Financial Statements for the first quarter 2013 and the second quarter 2013. A copy of each report is attached as Attachment B to this document.

1.0 Energy Probe-2

Ref: Exhibit 1, Tab 1, Schedule 13

Are any of the costs of the Board of Directors of the companies shown in diagram allocated to BPI and included in the historical cost data or the test year forecast? If yes, please show the amounts allocated by year, the company they are allocated from and the basis upon which this allocation has been made.

Response: The costs for the Brantford Power Board of Directors are as follows:

Brantford Power Board of Directors Costs	
2008	$83,746
2009	$53,050
2010	$48,427
2011	$44,935
2012 (Actual)	$47,156
2013	$69,867

There were previously costs for Brantford Energy management fees allocated to BPI. The table below provides the amounts paid between 2008 and 2011. As mentioned in the rate application on Exhibit 4, Tab 2, Schedule 4, page 19 of 26 and page 26 of 26, these costs were removed in 2012 and 2013.

2008	$ 176,889
2009	$ 118,960
2010	$ 124,125
2011	$ 151,041

The Brantford Energy Corporation (BEC) Board of Directors' costs were previously allocated 90% to BPI and 10% to Brantford Hydro Inc. (BHI) and Brantford Generation Inc. (BGI). This allocation was based on a historical figure that valued the assets of each company. The basis of the allocation was changed in the year 2009 to 60% BPI and 40% BHI and BGI. The basis of this updated allocation was the estimate of time that that BEC spent dealing with matters pertaining to each of the companies.

1.0 Energy Probe-3

Ref: Exhibit 1, Tab 2, Schedule 1

At page 4 of the schedule the evidence indicates that the information presented in the application represents BPI's forecast results for the 2013 test year, along with the forecasted results for the 2012 bridge year.

a) How many months of actual data for the 2013 test year, if any, are included in the OM&A forecasts for capital expenditures, OM&A and/or revenues?

Response: There were not any months of actual data used for the 2013 Test Year.

b) How many months of actual data are included in the 2012 bridge year forecasts for each of capital expenditures, OM&A, depreciation, revenues (including other revenue) and PILs?

Response: As stated in Exhibit 4, Tab 2, Schedule 1, page 4 of 4, the 2012 Bridge Year forecast is based on actual expenses as of June 30, 2012

1.0 Energy Probe-4

Ref: Exhibit 1, Tab 2, Schedule 4

a) Please explain the significant increase in property taxes between 2012 and 2013 shown in Table 1.5.

Response: The 2012 property tax expense included only the interim instalment of $4,525.75 for Payment in Lieu of Property Taxes that is filed with the Minister of Finance annually. BPI has requested a review of the Assessment Roll Numbers that appear on the annual return as many of these have not been used for electricity transmission in years. BPI filed the 2012 return removing the disputed roll numbers and determined no additional payments were due at that time. As the outcome of the review is not known at this time, BPI included a budget of $12,000 for the 2013 annual return.

b) Please provide the actual historical property taxes for each year in the 2009 through 2012 period.

Response: Please find below a table providing actual historical property taxes for each year from 2009 to 2012.

2009	$ 10,498.77
2010	$ 11,271.80
2011	$ 9,051.50
2012	$ 4,525.75

1.0 Energy Probe-5

Ref: Exhibit 1, Tab 3, Schedule 1

Please provide a copy of the 2012 Audited Financial Statements.

Response: Please see Attachment C for the 2012 Audited Financial Statements.

1.0 Energy Probe-6

Ref: Exhibit 1, Tab 3, Schedule 2

Please update Table 1.6 to include actual data for 2012.

Response: Please find below a revised table 1.6 which now includes actual data for 2012.

Description	2008	2009	2010	2011	2012
OM&A as per Audited Financial Statements	**7,973,320**	**7,688,125**	**7,548,966**	**6,971,079**	**7,877,099**
Add Special Purpose Charge	0	0	376,534	0	-
Add IESO Fees and Penalties	54,424	51,567	51,566	51,758	56,177
Add Retailer RCB Avoided cost	30	0	0	0	-
Less Smart Meter Amortization	0	0	373,781	315,364	321,320
Less Property Taxes	11,149	10,498	11,272	9,052	4,526
Less OPA CDM	321,479	0	0	0	
Less Donations	1,150	1,125	7,075	1,450	22,250
OEB Trial Balance	**7,693,996**	**7,728,069**	**7,584,938**	**6,696,972**	**7,585,180**
OM&A Contra Account Adjustment	0	0	373,781	315,364	321,320
Total OM&A Expenses	**7,693,996**	**7,728,069**	**7,958,719**	**7,012,336**	**7,906,500**
Less Special Purpose Charge	0	0	376,534	0	0
Total Recoverable OM&A Expenses	**7,693,996**	**7,728,069**	**7,582,185**	**7,012,336**	**7,906,500**

1.0 Energy Probe-7

Ref: Exhibit 1, Tab 3, Schedule 5

a) Please provide copies of BEC's consolidated and non-consolidated 2012 Audited Financial Statements.

Response: Please see BEC’s Consolidated 2012 Audited Financial Statements as Attachment D and BEC’s 2012 Non-Consolidated Financial Statements.

b) Please provide a copy of the BEC Annual Report for 2012.

Response: Please see BEC’s Annual Report for 2012 as Attachment E.

1.0 SEC-2

Ref: Exhibit 1, Tab 3, Schedule 1

Please provide the following documents:

a) The Applicant's Audited 2012 Financial Statements

Response: Please see response to 1.0 Energy Probe-5.

b) Brantford Energy Corporations 2012 Non-Consolidated Financial Statements

Response: Please see response to 1.0 Energy Probe-7 a).

c) Brantford Energy Corporations 2012 Consolidated Financial Statements

Response: Please see response to 1.0 Energy Probe-7 a).

1.0 VECC- 1

Reference: Exhibit 1, Tab 2, Schedule 5, pg. 1/ 2013_Rev_Req_Work_Form_V3_March13 2013, 201130717

a) Please explain the discrepancy between the revenue deficiency of $1,409,559 given at page 1 of E1/T2/S5/pg.5 and the amount of $3,503,478 shown in the RRWF Excel spreadsheet.

Response: The amount of $3,503,478 is linked to column M of the Data Input Sheet which is the column where Interrogatory responses are updated. BPI assumed this column was to be updated at the time of Interrogatories as the column suggests. It has now been updated and the $3,503,478 amount is not relevant.

1.0 VECC- 2

Reference: Exhibit 1, Tab 2, Schedule 1, pg. 4

a) Please explain what portion of the 2013 revenue deficiency is being sought for recovery for the period between November 1, 2013 and April 30, 2014.

Response: The Application has been prepared on the assumption that 100% of the 2013 revenue deficiency would be recovered through a one-year period in which the approved rates are in place and BPI has assumed an implementation date of November 1, 2013. BPI seeks recovery of the full 2013 Test Year revenue deficiency.

1.0 HVAC 1

Ref: Exhibit 1, Tab 1, Schedule 13

1. Please confirm that “Brantford Hydro” was formerly the name of the regulated utility, and is now the name of a retail affiliate.

Response: BPI advises that up to 1997, the vertically integrated utility, which provided water, electricity-related and transit services was named the Public Utilities Commission of the City of Brantford. Electricity-related services included electric water heater and sentinel light rental services as well as electricity distribution. A restructuring of the Public Utilities Commission in 1997 saw the transfer of water and transit services to the Corporation of the City of Brantford. The electricity-related services identified above were delivered by the Hydro-Electric Commission of Brantford until 2000 under the name of “Brantford Hydro”. Upon deregulation of the electricity sector, electric water heater and sentinel light assets previously branded as “Brantford Hydro” from 1997 were transferred to the newly incorporated (in 2000) retail affiliate, Brantford Hydro Inc. Electricity distribution services have been delivered by regulated entity incorporated as Brantford Power Inc. since incorporation on March 1, 2000.

As discussed in greater detail in response to HVAC Interrogatory 2 below, BPI has been advised that BHI is rolling out the “EnerSure” brand name for an expanded product line including natural gas water heaters, tankless water heaters and water conditioners in October 2013.

1.0 HVAC 2

Ref: Exhibit 1, Tab 1, Schedule 14

2. Please advise whether any additional unregulated affiliates are currently planned or expected. Please confirm that the corporate group has reserved the name "EnerSure" for unregulated businesses. Please advise which existing or expected members of the corporate group will be rebranded with this name, or any other new name, when, and for what business activities.

Response: BPI is not aware of any additional unregulated affiliates currently planned or expected.

The following is an extract from the Brantford Energy Corporation 2011 Annual Report regarding Brantford Hydro Inc., which describes the member of the corporate group and the business activities to be rebranded with the name "Enersure".

> *Brantford Hydro Inc. (BHI) has made a promising start in achieving its strategic goal to offer new products and services under a new home-based marketing banner. The expanded product line in the equipment rental business now includes natural gas water heaters, tankless water heaters and water conditioners, complementing the existing line of electric water heaters. The new business primarily came from new residential customers through relationships developed with new home builders and service providers.*

The "Enersure" logo is below:

BPI has been advised that BHI is rolling-out the "Enersure" branding for the expanded product line including natural gas water heaters, tankless water heaters and water conditioners in October 2013.

1.0 HVAC 3

Reference: Exhibit 1, Tab 1, Schedule 14

3. Please confirm that the corporate group plans to expand its unregulated activities.

Response: BPI is not aware of plans for the corporate group to expand its unregulated activities beyond those activities discussed in BPI's response to HVAC Question 2.

1.0 HVAC 4

Reference: Exhibit 1, Tab 1. Schedule 14

4. Please file any business plans, strategic plans, or similar documents of the parent company, the utility, or any affiliate, that include any unregulated activities that will rely in whole or in part on assets, personnel, or shared services (including shared services shared via the City) from the regulated utility. In each case please provide details of the nature, quantity and value of assets, personnel and shared services that will be used, and how the Applicant is ensuring that there is no ratepayer subsidy of unregulated activities.

Response: BPI's Strategic Plan for 2010 to 2013, which is its most current Strategic Plan, is attached as Attachment F to this document.

BPI is not aware of any business plans, strategic plans or similar documents of Brantford Energy Corporation [BEC] or its affiliates Brantford Hydro Inc. and Brantford Generation Inc.

As of April 1, 2012, BPI underwent a corporate restructuring that saw the transfer to BPI of those City of Brantford employees who provided services to BPI. Functions that had been shared among the Energy group of companies – specifically the Chief Financial Officer, Utilities Accounting [now Financial Support] and the Board Secretary were transferred to BPI. Assets, specifically computer hardware and software that had been shared among the corporate family, were transferred to BPI for its exclusive use as of January 1, 2013. As of May 6, 2013, BPI completed the separation of joint utility bills and began to issue customer invoices for electricity distribution and related charges only. The effect of these changes has been to eliminate sharing of assets, personnel and services between BPI and other entities in the Brantford Energy group of companies and ensures that there is no ratepayer subsidy of unregulated activities.

1.0 HVAC 5

5. Please file the Applicant's most recent ARC Compliance Report from the Board.

Response: BPI has not received an ARC Compliance Report from the Ontario Energy Board.

Exhibit 2 – Rate Base

2.0 Staff-4

Ref: Exhibit 2, Tab 2, Schedule 3, Page 5

Ref: Exhibit 2, Tab 3, Schedule 2, Appendix 2-A

In the first reference above, BPI has partially explained its 2012 Bridge Year variance through the purchase of a cube van for $325k. Vehicle replacements for 2012 as shown in Appendix 2-A and capital project descriptions appear to be $123,836.

a) Please explain the purchase price of $325k for this vehicle.

Response: The purchase price of $325,000 was the budget forecast for 2012 which included 4 vehicles. This forecast was not updated to reflect that BPI only purchased 1 vehicle (cube van).

b) Please provide an explanation for the remaining difference between the $325k cost of the vehicle and the $124k shown in Appendix 2-A.

Response: Please see 2-Staff-4 (a) response as it explains the remaining difference between the $325,000 cost of the vehicle and the $124,000 shown in Appendix 2-A.

2.0 Staff-5

Ref: Exhibit 2, Tab 3, Schedule 2, Page 2 &
Appendix 2-A & Asset Management Plan

Board staff notes that BPI has adjusted its Appendix 2-A to calculate the miscellaneous line as the difference between the total and subtotal amounts for each year in the table. The model provided to applicants includes the miscellaneous line as an input. Board staff further notes that the formula entered on line 33 of the model deducts the total on line 36 from the subtotal on line 32, resulting in negative miscellaneous amounts for the years 2013, 2012 and 2009.

a) Please confirm that the miscellaneous amounts in 2009, 2012 and 2013 should be positive amounts based on the project information provided in the table, and that the miscellaneous amounts in 2008, 2010 and 2011 would be negative.

Response: BPI has corrected the formula in line 33 of Appendix 2-A. The formula is now deducting the subtotal on line 32 from the total on line 36.

b) Please explain the negative spending amounts for 2008, 2010 and 2011.

Response: BPI has negative spending amounts for 2008, 2010 and 2011 because there was a mismatch between projects done and capital contributions collected.

c) Please provide a breakdown of the miscellaneous spending in 2012 of $897,460.

Response: BPI advises that the 2012 bridge year budget of $5,208,471 was based on 6 months of actual spending and 6 months of forecasted spending. Appendix 2-A was completed at a later date, when more updated actual capital spending was available. The difference between initial and later estimates contributed to the miscellaneous spending in the amount of $897,460. BPI’s 2012 actual capital program was $3,935,915. The difference between the 2012 forecast and the 2012 actual program of $1,272,556 explains the forecasted miscellaneous spending set out in the Capital Projects Table.

d) Please confirm that BPI's planned capital spending is $3,440,160, consistent with BPI's Asset Management Plan.

Response: BPI confirms that based on the update to forecast prepared in response to interrogatories, the 2013 forecasted capital spend is $3,074,285. Those discretionary projects related to the distribution system in the capital plan are consistent with BPI's Asset Management Plan.

BPI uses the Asset Management Program to identify and prioritize the renewal projects that are discretionary in nature. In 2013, the Annual Pole Replacements & General Yearly Rebuilds project, consist of items identified in the Asset Management Program~~.~~ Some projects identified in the multiyear Asset Management Plan have been deferred to better align with the municipality's road and sewer reconstruction schedule as it is more cost effective to undertake both municipal and electrical distribution works in the an area at the same time.

If necessary, please provide a corrected Appendix 2-A.

Response: Below is BPI's corrected Appendix 2-A Capital Projects Table.

Appendix 2-A - Capital Projects Table

Projects	2008	Projects	2009	Projects	2010	Projects	2011	Projects	2012 Bridge Year	Projects	2013 Test Year
Reporting Basis	CGAAP		CGAAP		CGAAP		CGAAP		CGAAP		Modified CGAAP
Capital Project #1- Residential Seconary Services	$ 93,448	Capital Project #1- Residential Seconary Services	$ 112,524	Capital Project #1- Residential Seconary Services	$ 156,047	Capital Project #1- Residential Seconary Services	$ 118,230	Capital Project #1- Residential Seconary Services	$ 134,156	Capital Project #1- Residential Seconary Services	$ 110,000
Capital Project #2 - Overhead Line Extensions	$ 263,594	Capital Project #2 - Overhead Line Extensions	$ 206,127	Capital Project #2 - Overhead Line Extensions	$ 354,061	Capital Project #2 - Overhead Line Extensions	$ 352,871	Capital Project #2 - Overhead Line Extensions	$ 179,453	Capital Project #2 - Overhead Line Extensions	$ 265,000
Capital Project #3 - Underground Line Extensions	$ 330,157	Capital Project #3 - Underground Line Extensions	$ 236,335	Capital Project #3 - Underground Line Extensions	$ 483,721	Capital Project #3 - Underground Line Extensions	$ 327,251	Capital Project #3 - Underground Line Extensions	$ 351,833	Capital Project #3 - Underground Line Extensions	$ 280,000
Capital Project #4 - Overhead Transformers	$ 314,189	Capital Project #4 - Overhead Transformers	$ 202,555	Capital Project #4- Underground Transformers	$ 593,583	Capital Project #4 - Overhead Transformers	$ 83,450	Capital Project #4 - Overhead Transformers	$ 156,725	Capital Project #4 - Overhead Transformers	$ 45,000
Capital Project #5 - Underground Transformers	$ 617,980	Capital Project #5 - Underground Transformers	$ 277,149	Capital Project #5- Powerline Feeder Upgrades	$ 524,514	Capital Project #5 - Underground Transformers	$ 508,860	Capital Project #5 - Underground Transformers	$ 210,587	Capital Project #5 - Underground Transformers	$ 360,000
Capital Project #6- New Subdivisions and Townhomes	$ 838,213	Capital Project #6 - Powerline Feeder Upgrades	$ 353,641	Capital Projects #6 - New Subdivisions and Townhomes	$ 265,408	Capital Project #6 - Powerline Feeder Upgrades	$ 489,849	Capital Project #6 - Powerline Feeder Upgrades	$ 692,218	Capital Project #6 - Powerline Feeder Upgrades	$ 450,000
Capital Project #7City/Ministry of Transportation Relocates	$ 103,262	Capital Project #7 - New Subdivisions and Townhomes	$ 1,654,016	Capital Project #7 - Scada & Distribution/ System Upgrade to Windows	$ 246,707	Capital Projects #7 -New Subdivisions and Townhomes	$ 328,556	Capital Project #7 New Subdivisions and Townhomes	$ 841,872	Capital Project #7 New Subdivisions and Townhomes	$ 446,100
Capital Project #8 - Scada & Distribution Automation/Brantford General Hospital Automatic Load Transfer System	$ 179,175	Capital Project #8 - Scada & Distribution Automation/Reloser Installation	$ 96,919	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ 432,011	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ 613,691	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ 660,709	Capital Project #8- Scada & Distribution Automation	$ 150,000
Capital Project #9- Conversion of Lines from 4 & 8 Kv to 27 KvSystem - Applewood & Brier Park Subdivision	$ 1,960,631	Capital Project #9 - Conversion of Lines from 4 & 8 Kv to 27 Kv System - Tranquility, Rosewood, etc.	$ 1,402,272	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park	$ 1,537,546	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park/Dunsdon Rebuild	$ 1,468,877	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Lynden Hill Estates	$ 1,096,019	Capital Project #9- Capacitor Study/Installation of Line Banks	$ 120,000
Capital Project #10- Annual Pole Replacements - General Yearly Rebuilds	$ 471,404	Capital Project #10 - Annual Pole Replacements - General Yearly Rebuilds	$ 512,324	Capital Project #10- - Metering	$ 355,369	Capital Project #10 - Asset Management & Consultancy Software	$ 219,196	Capital Project #10 - Asset Management & Consultancy Software	$ 230,987	Capital Project #10- Ownership Transfers - Primary Services and older 27.6Kv Townhome Sites	$ 110,000
Capital Project #11 - AM/FM GIS System Upgrade	$ 241,944	Capital Project #11 - Testing of G-Technology Version 9.4	$ 70,814	Capital Project #11- - Wholesale Metering (Brantford TS)	$ 769,365	Capital Project #11 Upgrade to G-Technology Version 10	$ 75,249	Capital Project #11 - Replacement of Vehicles	$ 123,836	Capital Project #11 Annual Pole Replacements - General Yearly Rebuilds	$ 390,000
Capital Project #12 - Metering	$ 229,050	Capital Project #12 - Metering	$ 349,517	Capital Project #12- Replacement of Vehicles	$ 248,832	Capital Project #12 - Metering	$ 150,239	Capital Project #12 - Office Furniture & Computer Equipment	$ 106,553	Capital Project #12 - Asset Management Consultancy &Software	$ 150,000
Capital Project #13 - Replacement of Vehicles	$ 165,750	Capital Project #13 - Replacement of Vehicles	$ 312,919			Capital Project #13- - Wholesale Metering (Brantford TS)	$ 26,781	Capital Project #13 - Metering	$ 129,614	Capital Project #13 - Metering	$ 205,000
						Capital Project #14 - Replacement of Vehicles	$ 309,767			Capital Project #14 - Replacement of Vehicles	$ 200,000
										Capital Project #15 - Customer Services (CS) Requirements	$ 160,000
										Capital Project #16 - City/MTO Relocation Overhead	$ 100,000
Capital Contributions	-$ 627,570	Capital Contributions	-$ 745,257	Capital Contribtuions	-$ 196,588	Capital Contributions	-$ 265,560	Capital Contributions	-$ 605,551	Capital Contributions	-$ 203,440
Sub Total:	$ 5,181,227	Sub Total:	$ 5,041,855	Sub Total:	$ 5,770,576	Sub Total:	$ 4,807,307	Sub Total:	$ 4,309,011	Sub Total:	$ 3,337,660
Miscellaneous	-$ 22,289	Miscellaneous	$ 88,042	Miscellaneous	-$ 101,275	Miscellaneous	-$ 226,611	Miscellaneous	$ 897,460	Miscellaneous	$ 102,500
Total:	$ 5,158,938	Total	$ 5,129,897	Total:	$ 5,669,301	Total:	$ 4,580,696	Total:	$ 5,206,471	Total:	$ 3,440,160

2.0 Staff-6

Ref: Exhibit 2, Tab 3, Schedule 2, Page 2 &
Exhibit 2, Tab 3, Schedule 2, Page 9 &
Appendix -2-A

BPI explains its decline in capital spending in 2011 as having been the result of no conversion projects occurring in that year. Board staff notes that no conversion projects are described or included in Appendix 2-A for 2010, 2011, 2012 or 2013. BPI's increased spending in 2012 is described as "a return to a normal level" of capital spending.

a) When was BPI's conversion project completed?

Response: In the main, BPI's long-term conversion projects which involved the upgrade of 4kV and 8 kV assets to a standard 27 kV standard were completed in 2009. There relatively small amounts of 4 kV and 8 kV assets servicing townhomes and condominiums that will be upgraded in the future.

b) Did BPI undertake any conversion projects in 2010? If so, where have they been included in BPI's capital projects evidence?

Response: BPI did not undertake any conversion projects in 2010. In the 2010 capital plan, conversion projects were replaced by general yearly rebuild projects. The specific 2010 project was Capital Project #9 – Brantwood Park General Yearly Rebuilds.

c) If no conversion projects were undertaken in 2010, please explain the decrease in spending in 2011.

Response: The decrease in spending in 2011 compared to 2010 was a result of a change in projects undertaken by BPI. In 2010, BPI spent $769,365 installing Wholesale

Meters at its Brantford Transformer Station and $246,707 upgrading its SCADA software/hardware from a Virtual Memory System to a Windows platform.
In 2011, BPI did not undertake projects of similar scope and cost resulting in the decrease in capital spending in 2011.

d) Does BPI consider its conversion to be an exceptional project or business as usual?

Response: The conversion projects were undertaken as a long-term capital project to convert existing 4 and 8 kV systems to more efficient 27 kV systems. As such, BPI would have considered those conversion projects to have been exceptional projects. However, BPI considers the General Yearly Rebuild projects that have replaced the conversion projects as business as usual projects.

e) Please explain BPI's description of its 2012 spending level as a return to normal if conversions are exceptional.

Response: As discussed in response to 2-Staff-6d above, BPI considers that the General Yearly Rebuild projects that replaced the conversion projects starting in 2010 as business as usual projects.

2.0 Staff-7

Ref: Exhibit 2, Tab 3, Schedule 2 Appendix 2-A Capital Projects Table – Pole Replacement

BPI has indicated various amounts from 2008 to 2013 for pole replacements as follows: $471.4k for 2008, $512.3k for 2009, $1,537.5k for 2010, $1,469k for 2011 and $1,096k for 2012. Board staff notes that the pole replacement budget for 2013 is $390k, based on the asset management plan.

a) Please explain the variability in this expense type from 2008 to 2012.

Response: The “annual pole replacements – general yearly rebuilds” are Capital Project (CP) #10 – 2008, CP#10 – 2009, CP#8 – 2010, CP#8 – 2011, CP#8 – 2012, and CP#11 – 2013. These capital projects are distinctly different from CP#9 – 2010 – Brantwood Park Rehabilitation, CP#9 – 2011 – Brantwood Park / Dunsdon Rebuild and CP#9 – 2012 – Lynden Hills Estate. They are different in that the “annual pole replacement – general yearly rebuilds” occur at various locations within BPI’s service territory in any given year. CP#9 in each of 2010, 2011 and 2012 was where asset renewal was completed within a specific geographical area of BPI’s service territory.

The “annual pole replacement – general yearly rebuilds” vary between a minimum of $432,011 in 2010 and a maximum of $660,709 in 2012 over the period from 2008 to 2012.

2.0 Staff-8

Ref: Exhibit 2, Tab 3, Schedule 5, Appendix C & Appendix 2-A

Board staff notes that BPI's asset management plan shows a spending level pattern as follows:

2014 – increase 52%
2015 – increase 16%
2016 – increase 11%
2017 – decrease 28%

Board staff notes a similar pattern in the historical information, showing higher spending in the years between cost of service applications, culminating in a reduction of 34% between 2012 and 2013.

a) Please describe BPI's approach to address the pace of capital spending.

Response: The 2013 capital plan was based on the forecasted funding levels in 2013.

The approach to addressing the pace of capital spending in future years assumes a replenishment of earnings resulting from the outcome of the current cost-of-service rate application as a result of which retained earnings would be set aside for future capital investments. At the same time, the repayment of principal on existing third-party debt will free up debt capacity to allow for borrowings to fund future capital expenditures.

b) Please explain how BPI's asset management plan addresses the pace of capital spending.

Response: BPI's asset management plan provides a prioritized list of capital projects based on the overall risk of assets within the project boundaries. The plan does not assign a timeline as to when these projects must be undertaken nor does it takes into consideration the cost outlay required for undertaking the projects, as part of the prioritization. However, if a high priority project is not included within a capital plan, there is a possibility that the high risk assets may further deteriorate over time due to changes in condition, age or other factors that are used to determine their overall risk.

Hence, the pace of capital spending is determined by BPI's Management Team based on non-discretionary project needs first, available spending envelope, and then other discretionary projects including the ones coming out of the asset management plan.

2.0 Staff-9

Ref: Exhibit 2, Tab 3, Schedule 6, Page 2, Table 2.21

Board staff notes that the service quality indicators for telephone accessibility have trended down since 2008, from 80% to 54% in 2013. BPI has explained the below standard SQI in 2012 as the result of vacancies at the time of employee transfers from the City of Brantford.

a) Please provide an explanation for this decline in service quality since 2008.

Response: BPI notes that the service quality indicator for telephone accessibility has trended downward to from 80 per cent in 2008 to 64.7 per cent in 2012 with a 2013 target of 65 per cent based on the Board's minimum standard.

The corporate restructuring that occurred in 2012 is the most significant factor impacting the downward trend in the telephone accessibility SQI. On April 1, 2012, an equivalent 12 FTE Customer Service staff including vacant positions were transferred from the City of Brantford to BPI to provide services exclusively to BPI. However, there was not a corresponding decrease in the number of customer calls that the proportionately smaller number of Customer Services staff were required to answer. On the basis of seniority, Customer Services staff was given the opportunity to decide whether they wished to remain with the City of Brantford or transfer to BPI with the result that the longer-term, more experienced Customer Services staff remained with the City of Brantford.

b) Please explain the steps BPI proposes to take to reverse the decline in service quality.

Response: BPI has already taken a number of steps to reverse the decline in service quality and proposes further steps in the future.

In 2012, BPI repurposed a Customer Premises Representative position that was vacant due to the retirement of the incumbent as a Customer Services Representative position to handle customer calls and service requests.

In the 2013 test year budget, BPI has proposed an increase of 1 FTE Customer Services Representative position. Pending conclusion of the cost-of-service rate application, BPI has backfilled that position and other vacancies that have occurred since April 1, 2012 with employees for temporary employment agencies.

Throughout 2012 and 2013, BPI has provided additional in-house training for Customer Services staff.

Along with ongoing increased investment in staff training and development, further steps that BPI has proposed to reverse this decline in service quality include:

- Completion of the Systems Integration Study, the result of which is to leverage technology to achieve productivity improvements. The study will identify improvements to the Customer Information System to provide Customer Services staff with better tools to respond to customer inquiries and requests in a more efficient manner. As well, the study will identify other automation opportunities such as e-billing that BPI may pursue following business case analysis;

- A study of customer services business processes to identify ways in which those business processes can be improved and made more efficient to free up Customer Services staff time to respond to customer inquiries and requests; and

- Further development of the BPI website as a self-service source of customer information.

2.0 Energy Probe-8

Ref: Exhibit 2, Tab 1, Schedule 2

a) Please update Table 2.1 to reflect actual data for 2012.

Response: Below is BPI's update to Table 2.1 to reflect actual data for 2012.

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Average Net Book Value	$ 57,505,800	$ 57,342,802	$ 59,098,860	$ 60,935,057	$ 62,191,372	$ 60,876,958	$ 63,760,430
Working Capital Allowance*	$ 12,096,131	$ 12,295,065	$ 11,987,350	$ 12,779,357	$ 13,404,151	$ 14,430,654	$ 13,556,745
Rate Base	$ 69,601,931	$ 69,637,867	$ 71,086,210	$ 73,714,414	$ 75,595,523	$ 75,307,612	$ 77,317,175
*15% (2008-2012) & 13% (2013)					`		

b) Please indicate which years shown are based on CGAAP and which years, other than 2013, that are based on Modified CGAAP.

Response: Only 2013 is based on Modified CGAAP.

2.0 Energy Probe-9

Ref: Exhibit 2, Tab 2, Schedule 1

a) Please provide a revised Table 2.13 that reflects actual data for 2012.

Response: Please find below revised Table 2.13 reflecting actual data for 2012.

Appendix 2-B
Fixed Asset Continuity Schedule

Year: 2013

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Reallocate Smart Meters	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Reallocate Smart Meters	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 200,139	$ 1,963	$ 166,000	$ -	$ 368,102	-$ 326,271	-$ 647	-$ 112,129	$ -	-$ 439,047	-$ 70,945
CEC	1612	Land Rights (Formally known as Account 1906)		$ 88,033	$ -	$ -	$ -	$ 88,033	-$ 7,749	$ -	-$ 1,790	$ -	-$ 9,539	$ 78,494
N/A	1805	Land		$ 161,661	$ -	$ -	$ -	$ 161,661	$ -	$ -	$ -	$ -	$ -	$ 161,661
CEC	1806	Land Rights		$ 3,966	$ -	$ -	$ -	$ 3,966	$ -	$ -	$ -	$ -	$ -	$ 3,966
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ -	$ 1,163,732	-$ 194,530	$ -	-$ 27,086	$ -	-$ 221,616	$ 942,116
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,207,912	$ -	$ -	$ -	$ 4,207,912	-$ 889,381	$ -	-$ 108,104	$ -	-$ 997,485	$ 3,210,427
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ -	$ 74,427	-$ 30,085	$ -	-$ 1,360	$ -	-$ 31,445	$ 42,982
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 16,966,416	$ -	$ 200,025	$ -	$ 17,166,441	-$ 6,440,840	$ -	-$ 390,465	$ -	-$ 6,831,305	$ 10,335,136
47	1835	Overhead Conductors & Devices		$ 12,550,744	$ -	$ 952,900	$ -	$ 13,503,644	-$ 4,373,590	$ -	-$ 235,668	$ -	-$ 4,609,258	$ 8,894,386
47	1840	Underground Conduit		$ 13,658,533	$ -	$ 22,300	$ -	$ 13,680,833	-$ 5,327,722	$ -	-$ 235,277	$ -	-$ 5,562,999	$ 8,117,834
47	1845	Underground Conductors & Devices		$ 18,383,842	$ -	$ 999,200	$ -	$ 19,383,042	-$ 4,798,200	$ -	-$ 622,783	$ -	-$ 5,420,983	$ 14,162,069
47	1850	Line Transformers		$ 17,383,772	$ -	$ 452,900	$ -	$ 17,836,672	-$ 6,366,512	$ -	-$ 436,147	$ -	-$ 6,802,659	$ 11,034,013
47	1855	Services (Overhead & Underground)		$ 1,563,763	$ -	$ 97,400	$ -	$ 1,661,163	-$ 276,746	$ -	-$ 66,497	$ -	-$ 343,243	$ 1,317,920
47	1860	Meters		$ -	$ -	$ 161,160	$ -	$ 161,160	$ -	$ -	-$ 429,758	$ -	-$ 429,758	-$ 268,598
47	1860	Meters (Smart Meters)		$ -	$ 5,308,885	$ -	$ -	$ 5,308,885	$ -	-$ 878,737	-$ 305,322	$ -	-$ 1,184,059	$ 3,885,776
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 312	$ -	-$ 312	-$ 312
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ 41,938	$ 13,800	$ -	$ 55,738	$ -	-$ 28,840	-$ 27,585	$ -	-$ 56,425	-$ 687
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 435,328	$ -	$ -	$ -	$ 435,328	$ -	$ -	$ -	$ -	$ -	$ 435,328
10	1930	Transportation Equipment		$ 2,928,990	$ -	$ 200,000	$ -	$ 3,128,990	-$ 2,128,692	$ -	-$ 129,172	$ -	-$ 2,257,864	$ 871,126
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 143,992	$ -	$ 25,000	$ -	$ 168,992	-$ 75,675	$ -	-$ 15,651	$ -	-$ 91,326	$ 77,666
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 6,662	$ -	-$ 6,662	-$ 6,662
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls - Customer Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 697,287	$ -	$ 50,000	$ -	$ 747,287	-$ 196,759	$ -	-$ 36,074	$ -	-$ 232,833	$ 514,454
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 4,497,124	$ -	-$ 273,052	$ -	-$ 4,770,176	$ 899,099	$ -	$ 100,128	$ -	$ 999,227	-$ 3,770,949
N/A	2050	Plant Held for Future Use		-$ 0	$ -	$ -	$ -	-$ 0	$ -	$ -	$ -	$ -	$ -	-$ 0
	etc.							$ -						
								$ -						
		Total		$ 86,888,770	$ 5,373,737	$ 3,097,420	$ -	$ 95,360,113	-$ 30,523,713	-$ 1,000,324	-$ 3,147,086	$ -	-$ 34,711,123	$ 60,646,019

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	$ 129,172
Stores Equipment	
Net Depreciation	$ 2,983,914

b) Please provide a revised Table 2.14 that reflects the actual data for 2012, along with actual expenditures closed to rate base in 2013 along with the remaining forecast for the 2013 test year.

Response: The revised Table 2.14 below reflects actual data for 2012 along with actual expenditures closed to rate base in 2013 along with the remaining forecast for the 2013 test year.

Appendix 2-B

Fixed Asset Continuity Schedule

Year 2013

				Cost					Accumulated Depreciation					
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Reallocate Smart Meters	Additions	Disposals	Closing Balance	Opening Balance	Reallocate Smart Meters	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 200,139	$ 1,963	$ 310,000	$ -	$ 512,102	-$ 326,271	-$ 647	-$ 121,074	$ -	-$ 447,992	$ 64,110
CEC	1612	Land Rights (Formally known as Account 1906)		$ 89,022	$ -	$ -	$ -	$ 89,022	-$ 7,748	$ -	-$ 1,294	$ -	-$ 9,042	$ 79,980
N/A	1805	Land		$ 181,961	$ -	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ 5,968	$ -	$ -	$ -	$ 5,968	$ -	$ -	$ -	$ -	$ -	$ 5,968
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ -	$ 1,163,732	-$ 194,532	$ -	-$ 27,086	$ -	-$ 221,618	$ 942,114
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,507,912	$ -	$ -	$ -	$ 4,507,912	-$ 893,531	$ -	-$ 104,104	$ -	-$ 997,635	$ 3,510,277
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ -	$ 74,427	-$ 30,025	$ -	-$ 1,560	$ -	-$ 31,585	$ 42,842
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 16,966,416	$ -	$ 215,000	$ -	$ 17,181,416	-$ 6,440,840	$ -	-$ 374,253	$ -	-$ 6,815,093	$ 10,366,323
47	1835	Overhead Conductors & Devices		$ 12,550,744	$ -	$ 958,000	$ -	$ 13,508,744	-$ 4,373,530	$ -	-$ 243,122	$ -	-$ 4,616,652	$ 8,892,092
47	1840	Underground Conduit		$ 13,858,533	$ -	$ 35,000	$ -	$ 13,893,533	-$ 5,327,722	$ -	-$ 233,392	$ -	-$ 5,561,114	$ 8,332,419
47	1845	Underground Conductors & Devices		$ 18,593,842	$ -	$ 856,100	$ -	$ 19,449,942	-$ 4,788,200	$ -	-$ 640,974	$ -	-$ 5,429,174	$ 14,020,768
47	1850	Line Transformers		$ 17,383,772	$ -	$ 502,000	$ -	$ 17,885,772	-$ 6,365,512	$ -	-$ 447,040	$ -	-$ 6,812,552	$ 11,073,220
47	1855	Services (Overhead & Underground)		$ 1,563,785	$ -	$ 110,000	$ -	$ 1,673,785	-$ 270,746	$ -	-$ 56,061	$ -	-$ 326,807	$ 1,346,978
47	1860	Meters		$ -	$ -	$ 205,000	$ -	$ 205,000	$ -	$ -	-$ 427,843	$ -	-$ 427,843	-$ 222,843
47	1860	Meters (Smart Meters)		$ -	$ 5,329,835	$ -	$ -	$ 5,329,835	$ -	-$ 978,737	-$ 355,322	$ -	-$ 1,334,059	$ 3,995,776
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 500	$ -	-$ 500	-$ 500
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ 41,939	$ 77,500	$ -	$ 119,439	$ -	-$ 28,940	-$ 18,326	$ -	-$ 47,266	$ 72,173
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 435,329	$ -	$ -	$ -	$ 435,329	$ -	$ -	$ -	$ -	$ -	$ 435,329
10	1930	Transportation Equipment		$ 2,928,990	$ -	$ 200,000	$ -	$ 3,128,990	-$ 2,132,692	$ -	-$ 161,947	$ -	-$ 2,294,639	$ 834,351
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 143,992	$ -	$ 25,000	$ -	$ 168,992	-$ 73,675	$ -	-$ 17,781	$ -	-$ 91,456	$ 77,536
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls - Customer Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 697,337	$ -	$ 150,000	$ -	$ 847,337	-$ 196,759	$ -	-$ 31,605	$ -	-$ 228,364	$ 618,973
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 4,457,124	$ -	-$ 203,440	$ -	-$ 4,660,564	$ 863,069	$ -	$ 105,753	$ -	$ 968,822	-$ 3,691,742
N/A	2040	Plant Held for Future Use		-$ 0	$ -	$ -	$ -	-$ 0	$ -	$ -	$ -	$ -	$ -	-$ 0
	etc.							$ -					$ -	$ -
								$ -						
		Total		**$ 86,888,776**	**$ 5,373,737**	**$ 3,440,160**	**$ -**	**$ 95,702,673**	**-$ 30,558,713**	**-$ 1,008,324**	**-$ 3,157,531**	**$ -**	**-$ 34,724,568**	**$ 60,978,104**
									Less: *Fully Allocated Depreciation*					
10		Transportation							Transportation			$ 161,947		
8		Stores Equipment							Stores Equipment					
									Net Depreciation			$ 2,995,584		

c) Please indicate the reduction in 2013 capital additions as a result of moving to Modified CGAAP.

Response: BPI's 2013 capital additions reduced by $972,502 as a result of moving to Modified CGAAP.

d) Please indicate how much of the fully allocated depreciation shown in Table 2.14 of $161,947 is allocated to OM&A and to capital additions, respectively.

Response: Based on BPI's 2013 Budget for fleet allocation, 66.4% is allocated to OM&A and 33.6% is allocated to capital additions.

e) How does BPI account for any work-in-progress that may exist at the end of the year?

Response: BPI reviews all capital expenditures by project at the end of the year and determines which ones have not been completed. Any projects that are deemed "in progress" are allocated into the Work-in-Progress Account.

2.0 Energy Probe-10

Ref: Exhibit 2, Tab 2, Schedule 1

At page 6, the evidence indicates that the smart meter funding adder has generated revenues of $2,683,669.

a) Please indicate the period over which this revenue from the funding adder has been collected.

Response: This revenue from the funding adder has been collected from May 1, 2006 to April 30, 2012.

b) When was the smart meter rate adder discontinued?

Response: BPI discontinued its smart meter adder on April 30, 2012.

2.0 Energy Probe-11

Ref: Exhibit 2, Tab 2, Schedule 1 &
Exhibit 2, Tab 2, Schedule 3

a) Please explain why there are no disposals of transportation equipment shown in Table 2.14 in Exhibit 2, Tab 2, Schedule 1 when the evidence at page 6 of Exhibit 2, Tab 2, Schedule 3 indicates that the $200,000 in capital additions are to replace existing vehicles.

Response: There are no disposals of transportation equipment because the disposed transportation equipment has a net book value and accumulated depreciation equal to zero.

b) Please confirm that the vehicles scheduled to be replaced in 2013 are fully depreciated when replaced. If this cannot be confirmed, please indicate the remaining net book value of the vehicles when they were/will be replaced in 2013.

Response: Yes the vehicles scheduled to be replaced in 2013 are fully depreciated.

c) Has BPI disposed of any of the vehicles that were forecast to be replaced in 2013 as of the current time? If yes, please provide the proceeds from the disposition of these vehicles.

Response: Yes it has disposed of three vehicles. Below table shows the proceeds from the disposition of the three vehicles:

Vehicle #7032	Pickup truck	$1,347.50
Vehicle #7021	Cube Van	$6,765.00
Vehicle #7001	Pickup truck	$1,060.00
Total		**$9,172.50**

2.0 Energy Probe-12

Ref: Exhibit 2, Tab 2, Schedule 1 &
Exhibit 2, Tab 2, Schedule 3

The evidence at page 6 of Exhibit 2, Tab 2, Schedule 3 indicates that budgeted capital contributions and grants decreased by ($203,440) over 2012. However, a review of Tables 2.13 and 2.14 in Exhibit 2, Tab 2, Schedule shows that capital contributions and grants are forecast to decrease by $420,060 to ($203,440).

a) Please reconcile.

Response: BPI agrees with Board Staff's review of Tables 2.13 and 2.14 in Exhibit 2, Tab 2, Schedule 1, the correct decrease of capital contributions over 2012 should be $420,060 and not ($203,440). Hence, evidence submitted on page 6 of Exhibit 2, Tab 2, Schedule 3 indicating that budgeted capital contributions and grants decreased by ($203,440) over 2012 is not correct.

b) Please explain the significant drop in capital contributions and grants between 2012 and 2013.

Response: The primary reason for decrease in capital contributions between 2012 and 2013 is because the budget for new subdivisions/townhomes (capital project # 7 – New Subdivisions and Townhomes) decreased over the same period, hence there is a direct correlation to the significant drop in capital contributions and grants.

2.0 Energy Probe-13

Ref: Exhibit 2, Tab 3, Schedule 2

a) The evidence indicates that the grants and capital contributions forecast is not specific to the projects. How does BPI forecast grants and capital contributions?

Response: BPI's grants and capital contributions are not based on project specifics for future years' forecast, since this information is not available from the builders/developers and the City/MTO, for relocation projects, at the time of preparation of the budget. However, based on historical actual project contributions, BPI estimates an approximated percentage amount that is then used to project future years' costs.

b) Please update Table 2.18 to reflect actual data for 2012 and any updates for 2013 capital spending.

Response: Below is BPI's update to Table 2.18 to reflect actual data for 2012.

Table 2.18: Capital Spending Summary 2008 to 2013

Year	Total Distribution Plant ($)	Capital Contributions	Net Distribution Plant	General Plant	Total Capital net of Contributions	$ Increase/ (Decrease	$ Increase/ (Decrease
2008	5,223,617	(627,570)	4,596,046	562,891	5,158,937	(134,165)	-2.53%
2009	5,400,507	(745,257)	4,655,250	474,647	5,129,897	(29,040)	-0.56%
2010	5,393,722	(196,588)	5,197,135	472,167	5,669,302	539,405	10.51%
2011	4,288,465	(265,560)	4,022,905	557,791	4,580,696	(1,088,606)	-19.20%
2012	4,070,219	(605,551)	3,464,668	471,247	3,935,915	(644,782)	-14.08%
2013	2,881,100	(203,440)	2,677,660	762,500	3,440,160	(495,755)	-12.60%

2.0 Energy Probe-14

Ref: Exhibit 2, Tab 4, Schedule 1

With reference to the Board's Regulated Price Plan Price Report - May 1, 2013 to April 30, 2014 issued April 5, 2013, please show the derivation of the $0.08395 per kWh figure for the RPP price and the derivation of the $0.08717 per kWh figure for the non-RPP price shown in Appendix D for 2013.

Response: BPI has identified an error in the calculation of the non-RPP price in Appendix D for 2013. The figures in the Table ES-1: Average RPP Supply Cost Summary were used from the Board's Regulated Price Plan Report – May 1, 2013 to April 30, 2014.

The RPP price was derived by converting the "Average Supply Cost for RPP Consumers of $83.95 per MWh to $0.08395 per kWh.

The correct non-RPP price should be $85.45 per MWh, which is equivalent to $0.08545 per kWh. This is determined by adding the Forecast Wholesale Electricity Price of $19.33 per MWh to the "Impact of the Global Adjustment" of $66.12 per MWh.

BPI has calculated an updated Cost of Power with the Non-RPP commodity price at 0.08545 per kWh. The calculations are summarized in Attachment G.

2.0 SEC-2

Ref: Exhibit 2, Tab 3, Schedule 2, Page 1

Please update Appendix 2-A to include a column for Test Year.year-to-date actuals.

Response: Below Appendix 2-A Worksheet has been updated to provide actual (or expected) in-service dates for Test Year capital projects, amounts spent to-date on each project and forecast updated budget.

Appendix 2-A
Capital Projects Table

Projects	2008	Projects	2009	Projects	2010	Projects	2011	Projects	2012 Bridge Year	Projects	2013 Test Year	2013 YTD Actuals	2013 Forecast updated Budget
Reporting Basis	CGAAP		CGAAP		CGAAP		CGAAP		CGAAP	Reporting Basis	Modified CGAAP	Modified CGAAP	Modified CGAAP
Capital Project #1 - Residential Secondary Services	$ 93,048	Capital Project #1 - Residential Secondary Services	$ 112,324	Capital Project #1 - Residential Secondary Services	$ 136,037	Capital Project #1 - Residential Secondary Services	$ 119,290	Capital Project #1 - Residential Secondary Services	$ 134,136	Capital Project #1 - Residential Secondary Services	$ 110,000	$ 75,0[illegible]	$ 97,000
										In-service date	December 31, 2013		
Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
Capital Project #2 - Overhead Line Extensions	$ [illegible]	Capital Project #2 - Overhead Line Extensions	$ [illegible]	Capital Project #2 - Overhead Line Extensions	$ [illegible]	Capital Project #2 - Overhead Line Extensions	$ [illegible]	Capital Project #2 - Overhead Line Extensions	$ [illegible]	Capital Project #2 - Overhead Line Extensions	$ [illegible]	$ [illegible]	$ [illegible]
										In-service date	December 31, 2013		
Capital Contribution:	-$ 149,717	Capital Contribution:	-$ 19,133	Capital Contribution:	-$ 5,171	Capital Contribution:	-$ 19,917	Capital Contribution:	$ -	Capital Contribution:	$ -	-$ 11,277	$ -
Capital Project #3 - Underground Line Extensions	$ [illegible]	Capital Project #3 - Underground Line Extensions	$ [illegible]	Capital Project #3 - Underground Line Extensions	$ [illegible]	Capital Project #3 - Underground Line Extensions	$ [illegible]	Capital Project #3 - Underground Line Extensions	$ [illegible]	Capital Project #3 - Underground Line Extensions	$ [illegible]	$ [illegible]	$ [illegible]
										In-service date	December 31, 2013		
Capital Contribution:	-$ 311,990	Capital Contribution:	-$ 229,164	Capital Contribution:	-$ 90,367	Capital Contribution:	-$ 179,152	Capital Contribution:	-$ 302,528	Capital Contribution:	$ -	-$ 1,166	$ 249,012
Capital Project #4 - Overhead Transformers	$ [illegible]	Capital Project #4 - Overhead Transformers	$ 232,285	Capital Project #4 - Underground Transformers	$ 328,283	Capital Project #4 - Overhead Transformers	$ 63,430	Capital Project #4 - Overhead Transformers	$ 136,725	Capital Project #4 - Overhead Transformers	$ 45,000	$ 36,986	$ 30,000
										In-service date	December 31, 2013		
Capital Contribution:	-$ 5,933	Capital Contribution:	-$ 1,000	Capital Contribution:	-$ 13,132	Capital Contribution:	-$ 6,777	Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
Capital Project #5 - Underground Transformers	$ [illegible]	Capital Project #5 - Underground Transformers	$ [illegible]	Capital Project #5 - Powerline Feeder Upgrades	$ [illegible]	Capital Project #5 - Underground Transformers	$ [illegible]	Capital Project #5 - Underground Transformers	$ [illegible]	Capital Project #5 - Underground Transformers	$ [illegible]	$ [illegible]	$ [illegible]
										In-service date	December 31, 2013		
Capital Contribution:	-$ 79,098	Capital Contribution:	-$ 147,796	Capital Contribution:	$ -	Capital Contribution:	-$ 57,216	Capital Contribution:	-$ 64,186	Capital Contribution:	$ -	$ -	$ 30,366
Capital Project #6 - New Subdivisions and Townhomes	$ 936,313	Capital Project #6 - Powerline Feeder Upgrades	$ [illegible]	Capital Projects #6 - New Subdivisions and Townhomes	$ [illegible]	Capital Project #6 - Powerline Feeder Upgrades	$ [illegible]	Capital Project #6 - Powerline Feeder Upgrades	$ [illegible]	Capital Project #6 - Powerline Feeder Upgrades	$ [illegible]	$ [illegible]	$ [illegible]
										In-service date	December 31, 2013		
Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:		Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
Capital Project #7 City/Ministry of Transportation Relocates	$ [illegible]	Capital Project #7 - New Subdivisions and Townhomes	$ [illegible]	Capital Project #7 - Scada & Distribution System Upgrade to Windows	$ [illegible]	Capital Projects #7 - New Subdivisions and Townhomes	$ [illegible]	Capital Project #7 New Subdivisions and Townhomes	$ [illegible]	Capital Project #7 New Subdivisions and Townhomes	$ [illegible]	$ [illegible]	$ [illegible]
										In-service date	December 31, 2013		
Capital Contribution:	-$ 27,096	Capital Contribution:	-$ 9,770	Capital Contribution:	-$ 9,015	Capital Contribution:	-$ 4,096	Capital Contribution:	-$ 3,799	Capital Contribution:	$ 176,440	$ -	$ -
Capital Project #8 - Scada & Distribution Automation Brantford General Hospital Automatic Load Transfer System	$ [illegible]	Capital Project #8 - Scada & Distribution Automation Feeder Installation	$ 96,929	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ [illegible]	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ [illegible]	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ [illegible]	Capital Project #8 - Scada & Distribution Automation	$ [illegible]	$ [illegible]	$ 30,000
										In-service date	June 30, 2014		
Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
Capital Project #9 - Conversion of Lines from 4 & 8 KV to 27 KV System - Applewood & Briar Park Subdivision	$ [illegible]	Capital Project #9 - Conversion of Lines from 4 & 8 KV to 27 KV System - Tranquility, Rosewood, etc.	$ 1,402,272	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park	$ [illegible]	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park Duncan Rebuild	$ [illegible]	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Lynden Hill Estates	$ [illegible]	Capital Project #9 - Capacitor Study/Installation of Line Banks	$ [illegible]	$ [illegible]	$ [illegible]
										In-service date	December 31, 2013		
Capital Contribution:	-$ 50,497	Capital Contribution:	-$ 42,454	Capital Contribution:	-$ 66,022	Capital Contribution:	$ -	Capital Contribution:	-$ 218,541	Capital Contribution:	$ -	$ -	$ -
Capital Project #10 - Annual Pole Replacements - General Yearly Rebuilds	$ [illegible]	Capital Project #10 - Annual Pole Replacements - General Yearly Rebuilds	$ 522,224	Capital Project #10 - Metering	$ [illegible]	Capital Project #10 - Asset Management & Consultancy Software	$ [illegible]	Capital Project #10 - Asset Management & Consultancy Software	$ [illegible]	Capital Project #10 - Ownership Transfers - Primary Services and older 27.6kV Townhome Sites	$ 110,000	$ 1,907	$ 10,000
										In-service date	December 31, 2013		
Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
Capital Project #11 - GIS System Upgrade	$ [illegible]	Capital Project #11 - Testing of G-Technology Version 9.4	$ 70,914	Capital Project #11 - Wholesale Metering (Brantford TS)	$ [illegible]	Capital Project #11 Upgrade to G-Technology Version 10	$ [illegible]	Capital Project #11 - Replacement of Vehicles	$ [illegible]	Capital Project #11 Annual Pole Replacements - General Yearly Rebuilds	$ [illegible]	$ [illegible]	$ [illegible]
										In-service date	December 31, 2013		
Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
Capital Project #12 - Metering	$ [illegible]	Capital Project #12 - Metering	$ 349,517	Capital Project #12 - Replacement of Vehicles	$ [illegible]	Capital Project #12 - Metering	$ [illegible]	Capital Project #12 - Office Furniture & Computer Equipment	$ [illegible]	Capital Project #12 - Asset Management Consultancy & Software	$ 120,000	$ 79,485	$ 170,000
										In-service date	December 31, 2013		
Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:		Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
Capital Project #13 - Replacement of Vehicles	$ [illegible]	Capital Project #13 - Replacement of Vehicles	$ 222,929			Capital Project #13 - Wholesale Metering (Brantford TS)	$ 39,781	Capital Project #13 - Metering	$ [illegible]	Capital Project #13 - Metering	$ 335,000	$ 36,227	$ 191,160
										In-service date	December 31, 2013		
Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
						Capital Project #14 - Replacement of Vehicles	$ [illegible]			Capital Project #14 - Replacement of Vehicles	$ 300,000	$ [illegible]	$ 300,000
										In-service date	October 31, 2013		
						Capital Contribution:	$ -	Capital Contribution:	$ -	Capital Contribution:	$ -	$ -	$ -
										Capital Project #15 - Customer Services (CS) Requirements	$ 150,000	$ -	$ -
										In-service date	June 30, 2014		
										Capital Contribution:	$ -	$ -	$ -
										Capital Project #16 - City/MTO Relocation Overhead	$ 100,000	$ 22,782	$ 30,000
										In-service date	June 30, 2014		
										Capital Contribution:	$ 25,000	$ -	$ -
										Capital Project #17 - Tools, Shop, etc.	$ 25,000	$ [illegible]	$ 25,000
										In-service date	December 31, 2013		
										Capital Contribution:	$ -	$ -	$ -
										Capital Project #18 - Office Furniture & Computer Equip.	$ [illegible]	$ [illegible]	$ 30,000
										In-service date	December 31, 2013		
										Capital Contribution:	$ -	$ -	$ -
Capital Contributions:	-$ [illegible]	Capital Contributions:	-$ [illegible]	Capital Contributions:	-$ [illegible]	Capital Contributions:	-$ [illegible]	Capital Contributions:	-$ [illegible]	Capital Contributions:	$ [illegible]	-$ [illegible]	-$ [illegible]
Sub Total:	$ [illegible]	Sub Total:	$ [illegible]	Sub Total:	$ [illegible]	Sub Total:	$ [illegible]	Sub Total:	$ [illegible]	Sub Total:	$ [illegible]	$ [illegible]	$ [illegible]
Miscellaneous	-$ 22,298	Miscellaneous	$ 66,023	Miscellaneous	-$ 101,375	Miscellaneous	-$ 226,911	Miscellaneous	$ [illegible]	Miscellaneous	$ -	$ 12,749	$ -
Total:	$ 5,128,938	Total:	$ 5,129,897	Total:	$ 5,689,201	Total:	$ 4,590,695	Total:	$ 5,205,471	Total:	$ [illegible]	$ [illegible]	$ [illegible]

2.0 SEC-4

Ref: Exhibit 2, Tab 3, Schedule 2, p.57-73

Please provide the specific actual (or expected) in-service date for all Test Year capital projects.

Response: Please see the response to 2-SEC-2.

2.0 SEC-5

Ref: Exhibit 2, Tab 3, Schedule 2, Page.57-73

For each Test Year capital project, please provide the amount of capital contribution (if any).

Response: Please see the response to 2-SEC-2.

2.0 SEC-6

Ref: Exhibit 2, Tab 3, Schedule 2, p.65

Is the Applicant eligible to receive any capital contributions from the IESO or Hydro One to offset the cost of the Study Report on BPI Powerline Municipal Transformation Station 27.6kV Capacitor & Reactive Support & Capacity Banks Installation- 27.6 kV Distribution System project.

Response: BPI is not eligible to receive any capital contributions from the IESO or Hydro One in relation to the Study Report on the BPI Powerline Municipal Transformer Station 27.6kV Capacitor & Reactive Support & Capacitor Banks Installation - 27.6kV Distribution System. The study is primarily looking at the distribution system security impacts related to the existing BPI feeder loads under normal and contingency conditions. The expected outcome of the study will be recommendations on where capacitors ought to be positioned on the BPI distribution system to maintain distribution system voltage within acceptable operating parameters under normal and contingency conditions. The study will consider the overall system voltage and power factor variations at the transformer station. The IESO and Hydro One are stakeholders in the study process as the installation of capacitors at the transformer station would have an impact on the Bulk Electricity System. The installation of capacitors on the BPI owned feeders connected to the transformer station would be for the benefit of BPI's present and future customers.

2.0 SEC-7

Exhibit 2, Tab 3, Schedule 2, p.71

How much has the Applicant spent in each year from 2009-2012 for vehicle replacements.

Response: Below table shows how much BPI has spent in each year from 2009-2012 for vehicle replacements.

Vehicle Type	2009	2010	2011	2012	Total
Covered Dump Trailer		$ 11,384			$ 11,384
Line truck			$ 281,255	$ 1,208	$ 282,463
Mid size pick up		$ 23,783			$ 23,783
Single Bucket Truck		$ 213,665			$ 213,665
Smaller Cube Van				$ 122,628	$ 122,628
Smaller Transit Connect			$ 28,512		$ 28,512
Yard/Crane Truck	$ 312,919				$ 312,919
Total	**$ 312,919**	**$ 248,832**	**$ 309,767**	**$ 123,836**	**$ 995,354**

2.0 SEC-8

Ref: Exhibit 2, Tab 3, Schedule 2

Please provide details of the planned capital expenditures for 2014-2017.

Response: Please find the 2014-2017 Capital Plan as Attachment H.

2.0 SEC-9

Ref: Exhibit 2, Tab 3, Schedule 5, Appendix B-5, p. 4

Please confirm that an asset that has a useful life of less than 30 percent does not necessarily mean that is has ‘extensive serious deterioration’.

Response: BPI confirms that an asset that has a useful life of less than 30 percent does not necessarily mean that is has ‘extensive serious deterioration’.

VECC – 3

Reference: Exhibit 2, Tab 1, Schedule

a) BPI notes that it undertakes capital projects for one of 4 reasons: (1) Renewal; (2) Security; (3) Capacity; and (4) Reliability. Please provide a breakdown of the capital expenditures from 2009 through 2013 by these categories.

Response: The table below shows a breakdown of the capital expenditures from 2009 through 2012 by category:

Capital Project #	2009	2010	2011	2012	2013
1	Capacity	Capacity	Capacity	Capacity	Capacity
2	Capacity	Capacity	Capacity	Capacity	Capacity
3	Capacity	Capacity	Capacity	Capacity	Capacity
4	Capacity	Capacity	Capacity	Capacity	Capacity
5	Capacity	Security/Capacity	Capacity	Capacity	Capacity
6	Security/Capacity	Capacity	Security/Capacity	Security/Capacity	Security
7	Capacity/Security	Reliability	Capacity	Capacity	Capacity
8	Security/Reliability	Renewal	Renewal	Renewal	Reliability
9	Renewal/Reliability	Renewal	Renewal	Renewal	Security
10	Renewal	Capacity	Renewal/Reliability	Renewal/Reliability	Capacity
11	Reliability	Renewal	Reliability	General Plant	Renewal
12	Capacity	General plant	Capacity	General Plant	Renewal/Reliability
13	General Plant	N/A	Renewal	Capacity	Capacity
14	N/A	N/A	General Plant	N/A	General Plant
15	N/A	N/A	N/A	N/A	General Plant

2.0 VECC – 4

Reference: Exhibit 2, Tab 3, Schedule 2, Appendix 2-A, Capital Projects Table.

a) Using Appendix 2-A, please show the capital contributions by project.

Response: Please see the response to 2-SEC-2.

2.0 VECC – 5

Reference: Exhibit 2, Tab 3, Schedule 2, Appendix 2-A

a) Please provide an update to Appendix 2-A showing the amounts spent to-date on each project, the estimated (or actual) date of completion or in-service and, if applicable, the forecast updated budget (or remaining amount forecast to be spent on the project).

Response: Please see the response to 2-SEC-2.

2.0 VECC – 6

Reference: Exhibit 2, Tab 3, Schedule 4, Table 2.19

a) In order to understand the materiality of BPI's proposed departures from the Kinectrics Study recommendations, please provide an estimate of the revenue requirement impact of maintaining the useful within the Kinectrics Study range.

Response: BPI chose useful lives that departed from the Kinectrics Study as identified in Table 2.19. Impacts on the revenue requirement are detailed below:

Wood Cross Arms on both Fully Dressed Concrete and Steel Poles

Typical useful life 40 years	BPI Decision 60 years

This departure from the Kinectrics Study would not impact the revenue requirement as these are not treated as a different component of the pole. BPI also does not typically use wood cross arms on steel or concrete poles.

Power Transformers - Bushing

Typical useful life 20 years	BPI Decision 45 years

BPI constructed a transformer station in 2005. Costs for bushings have been identified as $2,354. Annual amortization for this asset using the BPI decision would be $52. Annual amortization for this asset using the typical useful life BPI decision would be $118. This departure from the Kinectrics Study would increase the revenue requirement by $66.

Station DC System – Battery Bank

Typical useful life 15 years	BPI Decision 20 years

BPI constructed a transformer station in 2005. Costs for battery banks have been identified as $10,704. Annual amortization for this asset using the BPI decision would be $535. Annual amortization for this asset using the typical useful life BPI decision would be $714. This departure from the Kinectrics Study would increase the revenue requirement by $179.

Primary Paper Insulated Lead Covered (PILC) Cables

Typical useful life 65 years	BPI Decision 35 years

Primary Ethylene-Propylene Rubber (EPR) Cables

Typical useful life 25 years	BPI Decision 35 years

Primary Non-Tree Retardant Cross Linked Polyethylene Cables – Direct Buried

Typical useful life 25 years	BPI Decision 35 years

Primary Non-Tree Retardant Cross Linked Polyethylene Cables – In Duct

Typical useful life 25 years	BPI Decision 35 years

BPI identified one component called Primary Cables. The majority of the primary underground cable used in the past several decades has been tree retardant cross linked polyethylene. Any cable still in use that falls under the five components identified above, would be old and have little book value remaining. BPI is unable to determine the value of these components identified in the Kinectrics Study. Any impact on revenue requirement would be immaterial and would likely increase revenue requirement

Secondary Paper Insulated Lead Covered Cables

Typical useful life 75 years	BPI Decision 35 years

BPI identified one component called Secondary Cables. It was determined if there was any secondary paper insulated lead covered cables, they would be old and have little book value remaining. Any impact on revenue requirement would be immaterial.

2.0 VECC – 7

Reference: Exhibit 2, Tab 3, Schedule 6

a) Please provide the causes of service interruptions by category (see sample table below – or use similar descriptors employed by BPI).

Response: The table below provides BPI's causes of service interruptions by category from 2009 to 2012:

Description	2009 Totals	2010 Totals	2011 Totals	2012 Totals
Scheduled	57	96	41	97
Supply Loss	1	7	-	7
Tree Contact	1	7	7	1
Lightning	9	6	9	8
Def. Equip.(other than pole)	26	45	27	26
Pole Failure	-	-	-	-
Weather	7	12	7	3
Animals, Vehicles	49	65	47	37
Unknown	8	14	15	12
Total	**158**	**252**	**153**	**191**

2.0 VECC – 8

Reference: Exhibit 2, Tab 4, Schedule 1

a) Does BPI monthly or bi-monthly bill its customers? Has the billing cycle changed since the last Board cost of service rebasing?

Response: BPI bills its customers monthly and it has not changed its billing cycle since its last cost of service rebasing.

2.0 VECC – 9

Reference: Exhibit 2, Tab 5, Schedule 1

a) Please provide the capital and OM&A (separately) costs for 2013 that BPI expects to fund through distribution rates.

Response: BPI does not anticipate any capital or OM&A spending for Basic Green Energy Plan purposes. Therefore, it does not expect to fund capital and OM&A costs for 2013 through distribution rates.

Exhibit 3 – Operating Revenue

3.0 Staff-10

Ref: Exhibit 3, Tab 2, Schedule 1 – Estimated Regression Model

Board staff has prepared the following summary of the estimated regression model that BPI has used in its Application to estimate the base load forecast, before adjustment for 2012 and 2013 CDM program impacts:

Variable	**Description**	**Estimated Coefficient**	**t-Statistic**
Intercept	Constant term	(53,960,036.90)	(5.46)
Heating Degree Days (HDD)	Heating Degree Days at Lester B. Pearson Airport	15,963.03	14.90
Cooling Degree Days (CDD)	Cooling Degree Days at Lester B. Pearson Airport	110,374.36	19.19
Number of Days in the Month	Number of calendar days in the month	1,909,211.10	8.01
Real Ontario GDP	Chained GDP in constant 1997 $ for the Province of Ontario	549,023.30	10.59
April	Binary indicator variable for month of April	(4,364,938.90)	(6.47)
May	Binary indicator variable for the month of May	(3,385,062.27)	(4.63)
October	Binary indicator variable for the month of October	(2,029,353.76)	(2.81)
Negative Impact Variable	CDM variable constructed based on OPA reports for CDM program impacts from 2006 onwards; 0 prior to 2006	(5.71)	(15.55)

The regression statistics indicate that the included variables have estimated coefficients that are statistically significant at a 95% confidence level and that have the correct signs, as appropriate.

a) Please confirm or correct the above summary table.

Response: BPI confirms this summary table is correct.

b) What other variables were tried in the model, and why were these variables rejected in favour of the proposed model?

Response: The table below sets out the other variables tried in the load forecast model and the reasons for rejecting those variables:

Variable	Reason for rejection
Number of customers	Non- intuitive relationship
March Flag	|t|<2
September Flag	|t|<2
November Flag	|t|<2
Spring/ Fall Flag	|t|<2
Brantford Unemployment Rate	|t|<2
Brantford Population	|t|<2 and non-intuitive relationship
Brantford Employment	|t|<2 and non-intuitive relationship

c) The number of days in the month would, in part, also correlate with the number of working days in the month and hence economic activity, although when the month starts and the number of weekend days in the month would add some variability to this. HDD and CDD would also, in large part, also reflect seasonal impacts. The inclusion of binary variables for each of the months of April, May and October, and all with statistically significant and negative coefficients suggests that there are some seasonal (spring and fall saddle period) impacts not being accounted for by the HDD and CDD and days in the month.

i. How and why did BPI decide to test and then include binary monthly variables for these three months?

Response: As indicated in the answer to section (b), BPI attempted to include a Spring/Fall Flag (binary variable) to account for the spring and fall saddle period. BPI was aware this variable is commonly used in other Board-Approved load forecasts and has been used to address the seasonal impacts not being accounted for specifically by the HDD and CDD.

The results of a regression which included this variable showed that the variable was not statistically significant (the t-statistic was close to an absolute value of 2, but not above 2). As a result, BPI made another attempt which included separate variables for each of the Spring and Fall saddle months: March, April, May, September, October and November. Of these variables, BPI rejected the variables which were shown not to have a statistically significant impact on Power Purchases (variables with |t|<2). Only the April, May and October were included in the final model.

ii. Does the need for and significance of these variables not suggest that there are other factors, or other form of model misspecification, in the base model specification omitting these variables?

Response: BPI understands there could be other factors and/or variables that could be statistically significant and intuitive that could improve the statistical results of the model. However, with the extensive time invested in preparing the load forecast along with exploring and rejecting other possible variables, once an R square of 92% and an adjusted R square of 91% was achieved along with a reasonable load forecast it was decided that the investigation of any other factors or variables was not required.

d) BPI describes the Negative Impact variable as follows: “The Negative Impact Variable grows each month at a constant value over the year. The negative impact variable not only reflects the impact of CDM on the load forecast but it also reflects the impact of economic conditions within the service area." A review of the sheets of the load forecast Excel spreadsheet indicates that the Negative Impact Variable corresponds with the CDM variable, a constructed variable that interpolates in a linear method the net annualized CDM savings of OPA-sponsored programs for BPI. The variable is zero to December 2005 but then increases in a linear fashion each year. Please provide for BPI's view that economic conditions in BPI's service territory are correlated with the constructed CDM variable.

Response: Since 2005 there is a general pattern of decline in power purchases that is more than the impact of net CDM results assumed in the development of the Negative Impact Variable. The decline could be attributed to such items not included in the CDM net results such as the difference between gross and net CDM results, the impact of customer perception on electricity pricing once smart meters were installed even though customers were not transitioned to TOU pricing, the real impact of TOU pricing and the impact of declining economic conditions in the BPI service area. BPI was not able to separately quantify the impact of these items. In addition, BPI was unable to discover a statistically acceptable variable that reflected the decline in economic conditions in BPI's service territory on the level of power purchases. As a result, BPI is unable to accurately comment on whether the declining economic conditions in BPI's service territory are correlated with the constructed Negative Impact variable.

3.0 Staff-11

Ref: Exhibit 3, Tab 1, Schedule 4 – "Negative Trend" Variable

BPI has included a Negative Trend variable in its estimated regression equation, with the estimated coefficient of the CDM variable being -5.71. The data for the CDM/Negative Impact variable are contained in tab "CDM Activity" of the load forecast excel spreadsheet.

Analysis of the spreadsheet indicates that a linear interpolation was used to interpolate the monthly values to sum to the reported annual OPA savings in each year. As a starting example, the 2005 CDM savings per the OPA reports are 2,666,105 kWh in 2005. Board staff notes that, as documented in the OPA reports, the reported annualized savings for the year are estimated as if all programs were in effect the full year from January 1 to December 31.

New CDM programs are implemented at various times in the year and hence will not have the full impact in the first year of implementation. In recent Decisions, the Board has approved the application of the half-year rule as an approximation to measure the real impact of CDM programs in their initial year.

For example, the actual impact of 2005 CDM programs on 2005 consumption should be 2,666,105/2 = 1,333,053 kWh. The monthly values in 2005 should be linearly interpolated from 0 such that the sum would equal the 1,333,053 kWh.

For 2006, the full annualized persistence of 2005 programs (i.e.,2,666,105 kWh) would be assumed, and the incremental annualized savings for 2006 should be divided by 2 to reflect the half-year impact of the 2006 CDM programs in the first year, 2006.

a) Please prepare a CDM activity variable that reflects the half-year rule impact of CDM programs in the first year.

Response: BPI has prepared a Negative Impact variable using the half-year rule. Below is a chart setting out the calculation of the annual values to be used in the variable.

	Total OPA Annual CDM Results (Net kWh)	Total New Results (Net kWh)	Half Year New Results (Net kWh)	Negative Impact Variable: Total Annual Results (Net kWh, half-year adjusted)
	(A)	(B)	(C)=1/2*(B)	(D)=(A)- (C)
2006	2,666,105	2,666,105	1,333,053	1,333,053
2007	4,053,225	1,387,120	693,560	3,359,665
2008	6,738,513	2,696,911	1,348,455	5,390,057
2009	13,068,447	6,943,327	3,471,663	9,596,784
2010	14,323,507	4,170,820	2,085,410	12,238,097
2011	17,662,675	4,515,479	2,257,740	15,404,936
2012	22,587,351	5,168,137	2,584,069	20,003,282
2013	22,462,102			22,462,102

b) Please re-run the regression model with this variable. Provide all regression statistics in the standard Microsoft Excel regression output format, and provide the regression model, including the construction of the CDM variable in this format.

Response: BPI has re-run the regression model using this variable. In the chart below, BPI has provided the regression statistics in the standard Excel format. The full regression model which uses this variable is attached as Attachment I.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.957
R Square	0.916
Adjusted R Square	0.910
Standard Error	1,892,531.205
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	8	4.36264E+15	5.453E+14	152.25572	3.53308E-56
Residual	111	3.97566E+14	3.582E+12		
Total	119	4.76021E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	(53,511,157.89)	9,854,871.11	(5.43)	0.00	(73,039,242.87)	(33,983,072.91)	(73,039,242.87)	(33,983,072.91)
Heating Degree Days	16,224.51	1,068.75	15.18	0.00	14,106.70	18,342.32	14,106.70	18,342.32
Cooling Degree Days	112,284.33	5,737.81	19.57	0.00	100,914.47	123,654.19	100,914.47	123,654.19
Number of Days in Month	1,905,123.78	237,972.89	8.01	0.00	1,433,564.61	2,376,682.95	1,433,564.61	2,376,682.95
Real Ontario GDP (chained $1997 with Base 100 in 1997)	543,951.74	51,498.62	10.56	0.00	441,903.78	645,999.69	441,903.78	645,999.69
April	(4,302,273.06)	673,034.63	(6.39)	0.00	(5,635,936.11)	(2,968,610.01)	(5,635,936.11)	(2,968,610.01)
May	(3,300,241.50)	729,154.08	(4.53)	0.00	(4,745,108.99)	(1,855,374.02)	(4,745,108.99)	(1,855,374.02)
October	(1,915,088.82)	720,616.96	(2.66)	0.01	(3,343,039.43)	(487,138.21)	(3,343,039.43)	(487,138.21)
Negative Impact Variable	(6.52)	0.42	(15.58)	0.00	(7.35)	(5.69)	(7.35)	(5.69)

c) Please provide PBI's views on the reasonableness of the estimated CDM coefficient being greater than unity in absolute value.

Response: BPI submits that the estimated CDM coefficient being greater than unity in absolute value is reasonable. The additional kWh reduction per net CDM kWh savings could be attributed to such items not included in the CDM net results such as the difference between gross and net CDM results, the impact of customer perception on electricity pricing once smart meters were installed even though customers were not transitioned to TOU pricing, the real impact of TOU pricing and the impact of declining economic conditions in the BPI service area.

d) Please provide KWHI's views of the reasonableness of multiplying the persistence of 2011 CDM programs on the 2013 forecast by the CDM coefficient.

Response: BPI submits that this is reasonable. The regression estimates the historic relationship between the program results and the level of power purchases. BPI sees no reason why this relationship should change in 2013. This is especially true keeping in mind that no savings from 2013 programs have been included in the 2013 forecast Negative Impact Variable, which could potentially have a different relationship on power purchases.

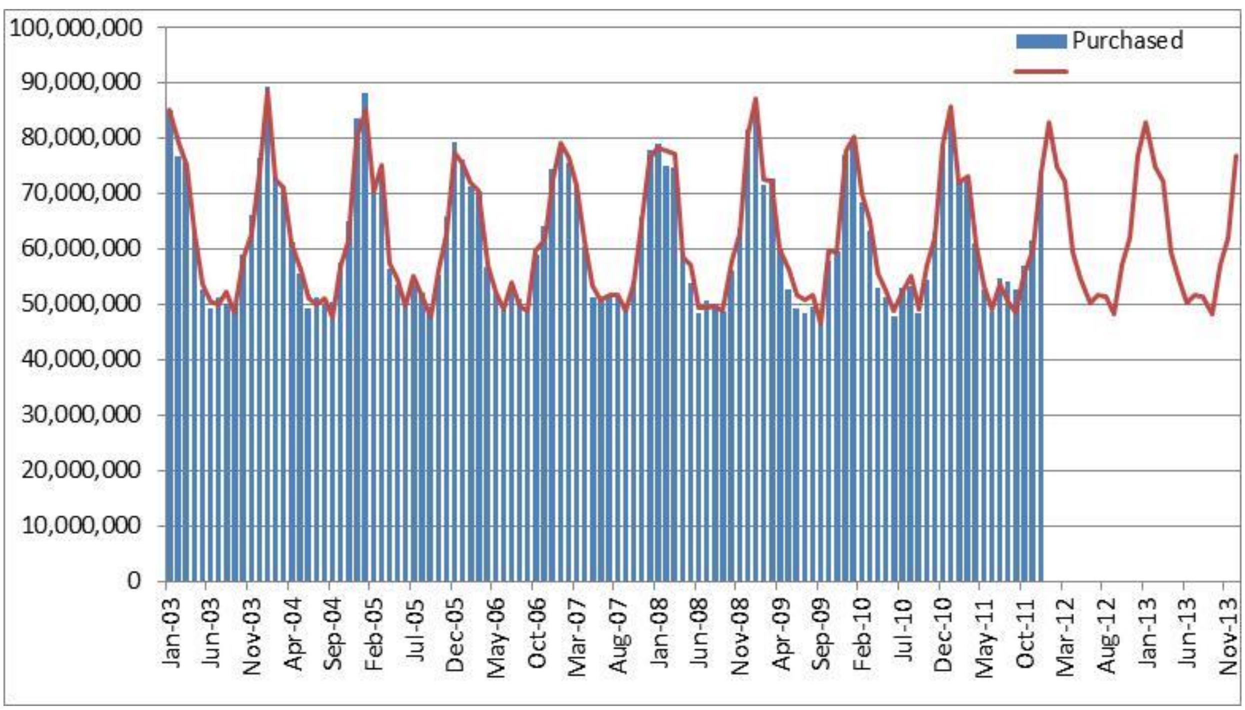
3.0 Staff-12

Ref: Exhibit 3, Tab 2, Schedule 1, Page 10

On page 10 of this exhibit, BPI has provide a graph showing the actual and predicted values for the regression model based on annual data.

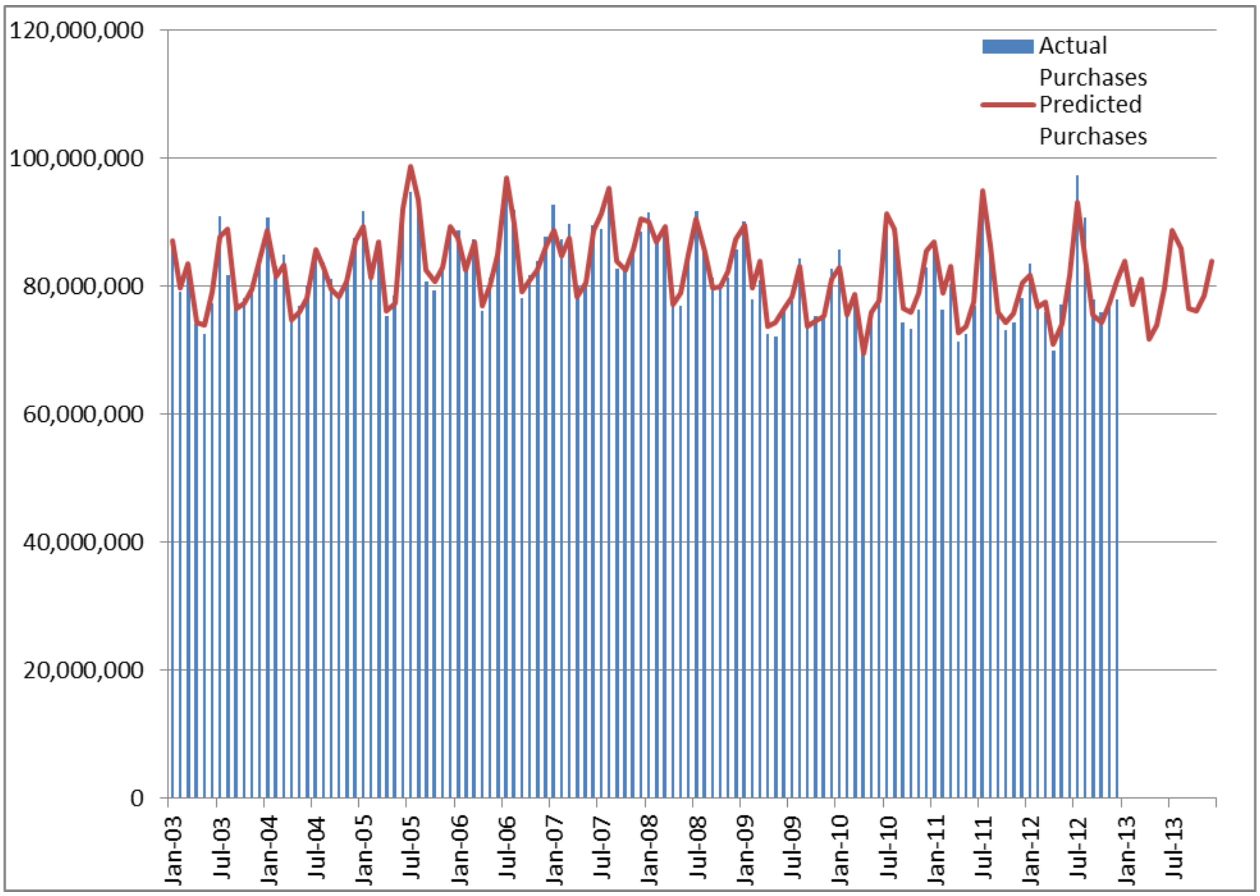
a) As the regression model is based on monthly data, please file a version of the graph of actuals versus fitted based on the monthly results in a format similar to that shown below.

Response:



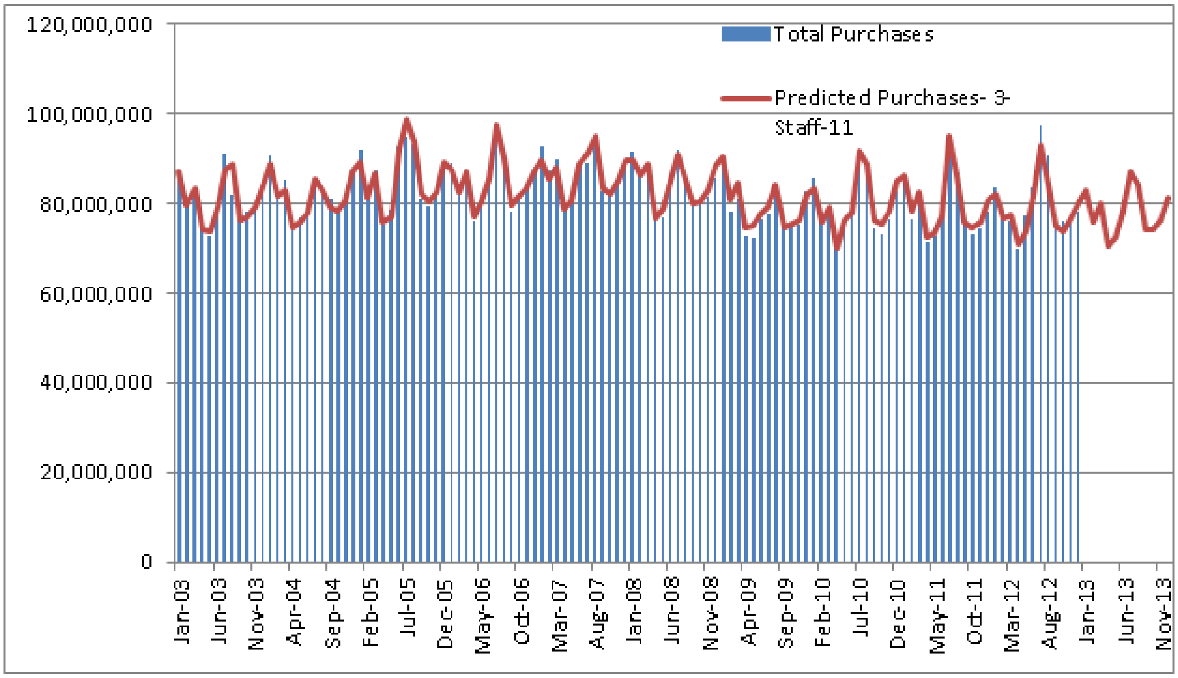
b) Please provide the Mean Absolute Percentage Error of the model based on the monthly residuals.

Response: The Mean Absolute Percentage Error of the Model is 1.73% on a monthly basis.



c) Please provide a) and b) based on the model estimated in response to 3-Staff-1

Response: The MAPE for the model estimated in response to 3-Staff-11 is 1.69% on a monthly basis.


Total Purchases
Predicted Purchases- 3-Staff-11
120,000,000
100,000,000
80,000,000
60,000,000
40,000,000
20,000,000
0
Jan-03
Jun-03
Nov-03
Apr-04
Sep-04
Feb-05
Jul-05
Dec-05
May-06
Oct-06
Mar-07
Aug-07
Jan-08
Jun-08
Nov-08
Apr-09
Sep-09
Feb-10
Jul-10
Dec-10
May-11
Oct-11
Mar-12
Aug-12
Jan-13
Jun-13
Nov-13

3.0 Staff-13

Ref: Exhibit 3, Tab 2, Schedule 1, Table 3.15

a) Please provide a copy of the final 2012 OPA report for BPI, if available.

Response: Please see BPI's 2012 Final OPA CDM Results as Attachment J.

b) Please provide an updated of Table 3.15 based on final CDM savings for 2012 as reported by the OPA for BPI's service territory.

Response: BPI submits the following updated Table 3.15 based on the final CDM Report.

Table 3.15- Updated for 2012 Final OPA CDM Report: Schedule to Achieve 4-year kWh CDM Target

4 Year 2011 to 2014 target				
48,920,000				
2013 Proposed Cost of Service Method				
2011	2012	2013	2014	Total
9.2%	9.2%	9.2%	9.0%	36.61%
	11.0%	10.7%	10.6%	32.25%
		10.4%	10.4%	20.76%
			10.4%	10.38%
9.2%	20.2%	30.3%	40.3%	100.00%
4,515,479	4,502,851	4,498,762	4,394,084	17,911,176
	5,363,496	5,232,705	5,179,494	15,775,695
		5,077,709	5,077,709	10,155,419
			5,077,709	5,077,709
4,515,479	9,866,347	14,809,177	19,728,997	48,920,000

3.0 Energy Probe-15

Ref: Exhibit 3, Tab 2, Schedule 1

Please provide the regression coefficients (as shown on page 6), the regression statistics (Table 3.5) and the 2013 forecast (Table 3.6 10 year average only) and the Mean Absolute Percent Error (MAPE) for each of the following equations:

a) As filed, but with the addition of a trend variable that starts with a value of 1 in the first month and increases by 1.0 each month;

Response: Please see the updated provided below reflecting the requested equation. The MAPE for this equation is 0.65%.

Regression Coefficients updated for 3-Energy Probe-15 a)

Intercept		(87,339,765.32)
+ Heating Degree Days	*	16,085.03
+ Cooling Degree Days	*	111,156.45
+ Number of Days in Month	*	1,893,613.00
+ Real Ontario GDP (chained $1997 with Base 100 in 1997)	*	825,898.98
+ April	*	(4,343,311.57)
+ May	*	(3,337,831.95)
+ October	*	(1,972,705.56)
+Nagative Impact Variable	*	(1.80)
+Trend Variable	*	(105,249.02)

Table 3.5-Updated for 3-ep-15 (a)	Regression Statistics
Multiple R	96.11%
R Square	92.37%
Adjusted R Square	91.74%
ANOVA	
	df
Regression	9
Residual	110
Total	119
	t Stat
Intercept	(6.28)
Heating Degree Days	15.65
Cooling Degree Days	20.14
Number of Days in Month	8.28
Real Ontario GDP (chained $1	8.43
April	(6.72)
May	(4.76)
October	(2.85)
Negative Impact Variable	(1.44)
Trend Variable	(3.28)

Table 3.6- Updated for 3-EP-15(a): Total System Purchases (GWh)			
Year	Actual	Predicted	% Difference
2003	964.3	978.8	1.51%
2004	989.6	976.9	-1.29%
2005	1,025.7	1,027.3	0.16%
2006	1,022.8	1,017.6	-0.51%
2007	1,043.0	1,041.3	-0.16%
2008	1,013.4	1,013.0	-0.04%
2009	940.8	943.3	0.26%
2010	950.8	946.2	-0.48%
2011	944.9	957.8	1.36%
2012	964.4	957.5	-0.71%
2013 Weather Normal- 10 year average		958.1	

b) As in (a) above, but with the Negative Impact Variable Removed.

Response: Please see the updated provided below reflecting the requested equation. The MAPE for this equation on an annual basis is 0.67%.

Regression Coefficients updated for 3-Energy Probe-15 b)

Intercept		(99,597,179.41)
+Heating Degree Days	*	16,158.45
+Cooling Degree Days	*	111,585.68
+Number of Days in Month	*	1,886,074.64
+Real Ontario GDP (chained $1997 with Base 100 in 1997)	*	928,660.41
+April	*	(4,329,445.08)
+May	*	(3,310,555.90)
+October	*	(1,943,854.17)
+Trend Variable	*	(149,694.64)

Table 3.5-Updated for 3-ep-15 (b)	Regression Statistics
Multiple R	96.03%
R Square	92.22%
Adjusted R Square	91.66%
ANOVA	
	df
Regression	8
Residual	111
Total	119
	t Stat
Intercept	(9.00)
Heating Degree Days	15.66
Cooling Degree Days	20.15
Number of Days in Month	8.21
Real Ontario GDP (chained $1	13.73
April	(6.67)
May	(4.70)
October	(2.80)
Trend Variable	(16.40)

Table 3.6- Updated for 3-EP-15(b): Total System Purchases (GWh)			
Year	Actual	Predicted	% Difference
2003	964.3	982.0	1.83%
2004	989.6	976.7	-1.31%
2005	1,025.7	1,025.0	-0.06%
2006	1,022.8	1,017.8	-0.49%
2007	1,043.0	1,041.4	-0.16%
2008	1,013.4	1,012.2	-0.12%
2009	940.8	943.3	0.26%
2010	950.8	942.1	-0.92%
2011	944.9	957.1	1.29%
2012	964.4	962.2	-0.22%
2013 Weather Normal- 10 year average		958.8	

c) Please confirm that the MAPE of the equation as filed is 0.83%. If this cannot be confirmed, please provide the MAPE and the data used to calculate it.

Response: BPI confirms that on an annual basis the MAPE is 0.83%.

3.0 Energy Probe-16

Ref: Exhibit 3, Tab 2, Schedule 1

Please provide the actual number of customers for the most recent month in 2013 for which actual information is available, along with the number of customers in the same month in 2012 in the level of detail shown in Table 3.9.

Response: The actual number of customers for September 2013, the most recent month for which actual information is available, along with the number of customers in September 2012 is set out in the table below.

September Customer Numbers						
	Residential	GS<50	GS>50	Sentinel	Street Lights	USL
2012	34,962	2,720	416	617	10,208	443
2013	35,257	2,755	416	624	10,232	435

3.0 Energy Probe-17

Ref: Exhibit 3, Tab 2, Schedule 1

a) Please provide the actual kW usage for the Embedded Distributor for each month in 2010 through 2012.

b) Please provide the actual kW usage for the Embedded Distributor for each month of 2013 that is currently available.

Response: BPI provides the information requested in both sections a) and b) in the table below:

Embedded Distributor kW Used				
	2010	2011	2012	2013
Month	(a)			(b)
Jan	14,321	13,475	12,582	13,219
Feb	14,771	14,238	13,220	13,625
Mar	14,316	13,961	12,488	13,590
Apr	12,291	12,656	11,766	12,691
May	11,026	12,169	11,132	12,367
Jun	13,214	12,035	12,360	12,226
Jul	12,744	13,140	14,157	13,888
Aug	14,287	15,522	14,615	15,021
Sep	14,018	13,737	13,294	13,673
Oct	13,455	12,567	12,645	
Nov	11,055	11,240	12,390	
Dec	12,146	11,864	12,518	
Total	157,645	156,605	153,168	120,301

3.0 Energy Probe-18

Ref: Exhibit 3, Tab 3, Schedule 4, Appendix 2-F

a) Please confirm that the figures shown in Appendix 2-F for 2012 are all actual values. If this is not confirmed, please provide a revised Appendix 2-F that includes actual data for 2012.

Response: The values in Appendix 2-F as submitted for 2012 are bridge year forecasts and not actual numbers. BPI has provided the 2012 Actual data in the revised Appendix 2-F.

b) Please explain why there is no forecast for the disposal of the 3 vehicles being replaced in 2013 in account 4355.

Response: BPI's practice is to not include a forecast for disposals in the budget for account 4355. This has been done as these amounts tend not to be material, and also because proceeds from disposals are difficult to forecast accurately.

c) Please provide the most recent year-to-date actual revenues available in the same level of detail as shown in Appendix 2-F for 2013, along with the year-to-date revenues for the corresponding period in 2012.

Response: BPI submits the following Appendix 2-F, which includes the 2012 actuals requested in section (a) as well as the Year to Date actual data for September 2013 and September 2012.

Additionally, BPI has noticed that detailed account breakdowns were missing for accounts 4235- Miscellaneous Service Revenues and 4390- Miscellaneous Operating Revenues in Appendix 2F as it was originally filed. BPI has included this detail in this response.

Updated Appendix 2F- Other Operating Revenues & Continued Appendix 2F- Other Operating Revenues Account Detail (Continued Next Page)

USoA #	USoA Description	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	2012 Actual	2012 YTD Sept	2013 YTD Sept
						2012	2013			
	Reporting Basis						CGAAP			
4235	Misc. Service Revenue	$ 589,631	$ 575,804	$ 635,867	$ 469,500	$ 403,588	$ 422,134	$ 407,627.62	$ 295,988.72	$ 319,248.64
4225	Late Payment Charges	$ 108,433	$ 99,278	$ 7,651	$ 111,988	$ 122,798	$ 120,000	$ 124,194.23	$ 91,119.56	$ 105,049.64
4082	Retailer Services Revenue	$ 74,089	$ 80,804	$ 66,001	$ 53,469	$ 31,557	$ 38,639	$ 32,677.24	$ 23,342.88	$ 26,727.77
4080	SSS Admin Fees	$ 93,320	$ 93,675	$ 96,005	$ 99,725	$ 103,910	$ 104,830	$ 103,915.15	$ 77,637.29	$ 79,702.52
4084	Serv Trans by REQ (STR)	$ 26,850	$ 19,258	$ 17,861	$ 14,821	$ 18,441	$ 11,660	$ 18,549.67	$ 15,615.31	$ 13,609.53
4210	Rent from Electric Property	$ 96,294	$ 121,418	$ 103,842	$ 104,422	$ 106,000	$ 108,120	$ 105,560.39	$ 79,176.00	$ 81,143.60
4215	Other Utility Operating Inc	$ -	$ -	$ -	$ -	$ -	$ -			
4220	Other Electric Revenue	$ 2,833	$ 566	$ 1,088	$ 189	$ -	$ -			
4240	Provision for Rate Refunds	$ -	$ -	$ -	$ -	$ -	$ -			
4335	P&L from FI Hedges	$ -	$ -	$ -	$ -	$ -	$ -			
4355	Gain on Disposition of Utility and Other P	$ 4,550	-$ 22,969	$ 51,067	$ 19,025	$ -	$ -	$ 565.00	$ -	$ 9,172.50
4360	Loss on Disposal of Property	$ -	$ -	$ -	$ -	$ -	$ -			
4375	Revenue from Non-Utility Operations	$ 541,188	$ 2,189,506	$ 1,130,495	$ 723,014	$ 3,897,395	$ 5,165,361	$ 4,020,507.67	$ 1,956,610.61	$ 2,540,275.22
4380	Expenses from Non-Utility Operations	-$ 482,836	-$ 1,846,309	-$ 926,976	-$ 735,093	-$ 3,897,395	-$ 5,165,361	$ (3,683,840.23)	$ (1,950,840.61)	$ (2,538,852.96)
4390	Misc. Non-Operating Income	$ 70,259	$ 35,377	$ 37,989	$ 28,525	$ 12,800	$ 20,000	$ 16,350.11	$ 10,635.86	$ 4,702.56
4405	Interest & Dividend Income	$ 385,736	$ 128,823	$ 129,666	$ 278,195	$ 271,024	$ 275,539	$ 273,775.01	$ 184,778.68	$ 260,411.91
Specific Service Charges		$ 589,631	$ 575,804	$ 635,867	$ 469,500	$ 403,588	$ 422,134	$ 407,627.62	$ 295,988.72	$ 319,248.64
Late Payment Charges		$ 108,433	$ 99,278	$ 7,651	$ 111,988	$ 122,798	$ 120,000	$ 124,194.23	$ 91,119.56	$ 105,049.64
Other Operating Revenues		$ 293,386	$ 315,719	$ 284,797	$ 272,626	$ 259,908	$ 263,249	$ 261,267.45	$ 195,771.48	$ 210,355.92
Other Income or Deductions		$ 518,897	$ 484,428	$ 422,240	$ 313,666	$ 283,824	$ 295,539	$ 626,792.56	$ 201,184.54	$ 266,536.73
Total*		$ 1,510,346	$ 1,475,230	$ 1,350,554	$ 1,167,779	$ 1,070,118	$ 1,100,922	$ 1,419,881.86	$ 784,064.30	$ 901,190.93

Account 4210- Rent from Electric Property

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis					2012	2013	2012	2012	2013
Pole Rental Revenues		$ 121,418	$ 103,842	$ 104,422	$ 106,000	$ 108,120	$ 105,560.39	$ 79,176.00	$ 81,143.60
Total		$ 121,418	$ 103,842	$ 104,422	$ 106,000	$ 108,120	$ 105,560.39	$ 79,176.00	$ 81,143.60

Account 4220- Other Electric Revenue

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis					2012	2013	2012	2012	2013
Other Electric Revenue	$ 2,832.56	$ 566	$ 1,088	$ 189	$ -	$ -	$ -	$ -	$ -
Total	$ 2,833	$ 566	$ 1,088	$ 189	$ -	$ -	$ -	$ -	$ -

Account 4355-Gain on Disposition of Utility and Other Property

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis					2012	2013	2012	2012	2013
Gain on Disposition of Utility and Other Property	$ 4,550.00	-$ 22,969	$ 51,067	$ 19,025	$ -	$ -	$ 565.00	$ -	$ 9,172.50
Total	$ 4,550	-$ 22,969	$ 51,067	$ 19,025	$ -	$ -	$ 565.00	$ -	$ 9,172.50

Account 4375- Revenues from Non-Utility Operations

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis					2012	2013	2012	2012	2013
OPA Revenues and Incentives	$ 333,873.76	$ 1,848,103.66	$ 954,753.74	$ 691,180.42	$ 3,897,395.00	$ 5,165,361	$ 3,683,840.23	$ 1,950,840.61	$ 2,538,852.96
Street Light Revenue	$ 161,356.48	$ 60,929.46	$ -	$ -	$ -		$ -	$ -	$ -
CDM Bonus	$ 45,958.21	$ 280,473.21	$ 175,741.46	$ 31,833.43	$ -		$ 336,667	$ 5,770.00	$ 1,422.26
Total	$ 541,188	$ 2,189,506	$ 1,130,495	$ 723,014	$ 3,897,395	$ 5,165,361	$ 4,020,507.67	$ 1,956,610.61	$ 2,540,275.22

Account 4380- Expenses fron Non-Utility Operations

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis					2012	2013	2012	2012	2013
OPA Incentives and Expense	$ (321,479.75)	$ (1,785,379.37)	$ (926,976.27)	$ (735,092.98)	$ (3,897,395.00)	$ (5,165,361.00)	$ (3,683,840.23)	$ (1,950,840.61)	$ (2,538,852.96)
Street Light Revenue	-$ 161,356.48	-$ 60,929.46	$ -	$ -	$ -				
Total	-$ 482,836	-$ 1,846,309	-$ 926,976	-$ 735,093	-$ 3,897,395	-$ 5,165,361	$ (3,683,840.23)	$ (1,950,840.61)	$ (2,538,852.96)

Account 4405- Interest and Dividend Income

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis					2012	2013	2012	2012	2013
Interest on Taxes	$1,557.71	$59,271.79	$1,668.07	$ -	$ -	$ -	$ -	$ -	$ 6,701.07
Bank Deposit Interest	$341,698.74	$44,524.57	$83,436.45	$157,625.98	$130,500.00	$ 120,000.00	$ 156,712.93	$ 97,992.17	$ 148,644.54
Interest on Accounts Receivable	$998.11	$3,744.12	$1,125.01	$5,035.83	$1,200.00	$ 3,500.00	$ 1,012.10	$ 480.98	$ 2,852.84
Regulatory Asset Interest	$41,481.39	$21,282.06	$45,686.28	$115,533.28	$139,324.00	152,039.00	116,049.98	86,305.53	102,213.46
Total	$ 385,736	$ 128,823	$ 131,916	$ 278,195	$ 271,024	$ 275,539	$ 273,775.01	$ 184,778.68	$ 260,411.91

Account 4225- Late Payment Charges

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis					2012	2013	2012	2012	2013
Late Payment Charges	108432.71	$ 99,278	$ 7,651	$ 111,988	$ 122,798	$ 120,000	$ 124,194.23	$ 91,119.56	$ 105,049.64
Total									

Account 4390- Misc. Non-Operating Income

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge	Test Year	Actual	YTD Sept	YTD Sept
Reporting Basis						2013	2012	2012	2013
Sales of Scrap	$ 65,333.82	$ 30,452.35	$ 37,997.01	$ 21,202.41	$ 12,800.00	$ 20,000.00	$ 16,350.11	$ 10,635.86	$ 4,702.56
Other	$ 4,925.00	$ 4,925	$ (8.23)	$ 7,323	$ -	$ -	$ -	$ -	$ -
Total	**$ 70,259**	**$ 35,377**	**$ 37,988.78**	**$ 28,525**	**$ 12,800**	**$ 20,000**	**$ 16,350**	**$ 10,636**	**$ 4,703**

Account 4235- Misc. Service Revenue

		2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual	YTD Sept	YTD Sept
	Reporting Basis					2012	2013	2012	2012	2013
	MicroFIT Revenue			$ 163	$ 1,084	$ 3,003	$ 5,184	$ 2,820	$ 1,944	$ 2,789
	Arrears Certificate	$ 2,325	$ 1,907	$ 1,359	$ 1,543	$ 1,500	$ 150	$ 1,519	$ 1,144	$ 824
	Credit Check Fee	$ 9,030	$ 8,141	$ 7,207	$ 7,572	$ 6,200	$ 7,500	$ 5,107	$ 4,202	$ 2,290
	Returned Cheque Charge	$ 11,458	$ 10,030	$ 9,536	$ 7,300	$ 6,900	$ 6,750	$ 6,546	$ 5,243	$ 4,455
	New A/C Setup Fee	$ 176,040	$ 167,610	$ 170,730	$ 167,010	$ 155,400	$ 165,000	$ 157,890	$ 115,530	$ 116,730
	Field Collection Charge	$ 331,988	$ 347,961	$ 400,915	$ 256,316	$ 203,600	$ 210,000	$ 204,060	$ 149,220	$ 174,420
	Reconnection Charge	$ 25,840	$ 23,410	$ 26,394	$ 15,825	$ 14,100	$ 11,375	$ 15,130	$ 9,505	$ 8,655
	Electric Reconnect After Hours	$ 10,730	$ 8,965	$ 14,244	$ 9,165	$ 9,900	$ 8,325	$ 10,086	$ 6,101	$ 6,660
	Reconnect at Pole	$ 555	$ 2,035	$ 555	$ 185	$ 185	$ 185	$ 555	$ 185	$ 925
	Reconnect at Pole After Hours		$ 1,245			$ 500	$ 415	$ 415	$ 415	
	Temporary Hydro Service Charge	$ 5,500	$ 4,500	$ 4,500	$ 3,500	$ 2,300	$ 3,500	$ 3,500	$ 2,500	$ 1,500
	Secondary Service Install Fee	$ 16,165		$ 265			$ -			
	Load Control During Hours						$ 1,625			
	Meter Removal Without Authorization						$ 1,200			
	Load Control After Hours						$ 925			
1	**Total**	**$ 589,631**	**$ 575,804**	**$ 635,867**	**$ 469,500**	**$ 403,588**	**$ 422,134**	**$ 407,628**	**$ 295,989**	**$ 319,249**

3.0 Energy Probe-19

Ref: Exhibit 3, Tab 3, Schedule 4

Please explain concerns that BPI has with the privacy implications of continuing to provide a service related to Arrears Certificates.

Response: The issuance of arrears certificates resulted from the historical practice of placing utility arrears against a property on the municipal tax rolls. When the property was being sold, the purchaser, generally through their lawyer, would request an arrears certificate as the purchaser was held liable for the arrears. This practice ended with the restructuring of the electricity distribution sector in 2000.

The privacy concern is that the arrears certificate, in effect, provides personal financial information about an individual customer's account to another customer.

3.0 SEC-10

Ref: Exhibit 3, Tab 3, Schedule 3, Appendix 2-F

Please update Appendix 2-F to include Test Year year-to-date actuals.

Response: Please see the response to 3-Energy Probe-18 c) which includes Appendix 2-F updated to include Test Year year-to-date Actuals.

3.0 VECC – 10

Reference: Exhibit 3, Tab 1, Schedule 1, page 2

a) With respect to the Summary of Operating Revenue Table provided, please clarify the footnoted with the double star (**), by indicating, for each year, in which row under Other Distribution Revenue are Revenues from the Standby class included and what the annual values are.

Response: In every year but the 2012 Test Year, Standby Revenues have been included in Account 4080- Distribution Revenues. In 2013, the forecast revenues from the Standby Class are included in account 4080-2 (which is an Other Revenues account) with SSS Admin Fees.

This is depicted below:

	2008 Board Approved*	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 test at proposed rates
Distribution Revenue							
4080- Distribution Revenue- Standby	$ 37,679	$ 61,118	$ 59,499	$ 62,478	$ 66,547	$ 64,532	
Other Distribution Revenue							
4080-2- SSS Admin Fees		$ 93,320	$ 93,675	$ 96,005	$ 99,725	$ 103,910	$ 104,830
4080-2- Standby Revenues							$ 60,224
4080-2 Total							$ 165,054

3.0 VECC – 11

Reference: Exhibit 3, Tab 2, Schedule 1, page 3

a) Are the 2013 billed kWh values reported in Table 3.1 after the manual adjustment for CDM?

Response: Yes, BPI confirms the 2013 billed kWh values in Table 3.1 are after the manual CDM adjustment.

b) The text states that the numbers for Street Lights, Sentinel Lights and Unmetered reported in Table 3.2 are connections. However, Tab I6.2 of the Cost Allocation model reports 645 connections whereas Table 3.2 reports 10,355 for 2013. Please reconcile.

Response: This is an error in the text and labelling for Table 3.2. The 2013 Street Lights forecast is for 645 connections and 10,355 devices.

3.0 VECC – 12

Reference: Exhibit 3, Tab 2, Schedule 1, pages 6- 7

a) Please confirm that the values used for the Negative Impact Variable were calculated based on the net CDM savings from CDM programs implemented starting in 2006 through to programs implemented in 2012.

Response: BPI confirms that the values used for the Negative Impact Variable were calculated based on the net CDM savings from CDM programs implemented starting in 2006 through to programs implemented in 2012.

b) What are the savings attributed to 2012 CDM programs as used in the regression analysis based on?

Response: The savings attributed to 2012 CDM programs in 2012 and 2013 are forecasts for savings from 2012 Programs in 2012 and persisting savings from 2012 programs into 2013.

These amounts have been forecast taking into account the yearly savings necessary for BPI to reach its 2014 CDM target, given BPI's 2011 savings and their persistence until 2014 from its 2011 OPA Final Results report. This forecast assumes equal new savings in each of 2012, 2013 and 2014, and assumes 100% persistence from programs in these years.

This corresponds to table 3.15, E3/T2/S1 p17.

c) If available, please provide a copy of the OPA's final 2012 CDM Report for BPI? If this is not available, please provide any preliminary reports the OPA has produced regarding 2012 CDM program results.

Response: Please see response to 3-Staff-13 where BPI has provided the OPA's final 2012 CDM Report as Attachment J.

d) What other variables did BPI test in developing its load forecast model and why were they excluded?

Response: Please refer to the BPI's response to 3-Board Staff-10, Section b).

e) How does BPI interpret the -5.71 coefficient value that is calculated for the Negative Impact Variable?

Response: Please refer to the BPI's response to 3-Staff-11 c).

f) Is it reasonable to use, for load forecasting purposes, a model that assumes each kWh of CDM leads to an almost 7 kWh reduction in purchases? If so, why?

Response: BPI submits it is reasonable to use a model that relates 1 net OPA program kWh saving to a 5.7 kWh reduction in total system purchased power. This is based on the historical relationship estimated in BPI's Load Forecast Regression Analysis. The regression statistics indicate that this is a strong estimation, with a t-statistic for this coefficient of (-15.5). Please further refer to BPI's response in 3-Staff-11 c).

g) Please re-estimate the model excluding the Negative Impact Variable, provide the resulting equation and statistics and provide a forecast for 2013 using the revised model.

Response: Please see the equation and regression statistics for the model excluding the Negative Impact Variable. BPI notes that the regression's R-squared statistic has dropped to 73%, representing an almost 20% drop, and that this 73% is below the commonly acceptable range of R-squared statistics. Additionally, the MAPE of the requested equation is 3.51%, a large increase from the value of 1.73% for the original application.

Intercept		18,947,514.34
Heating Degree Days	*	16,831.46
Cooling Degree Days	*	114,298.83
Number of Days in Month	*	1,871,481.22
Real Ontario GDP (chained $	*	(12,518.04)
April	*	(4,177,229.06)
May	*	(3,094,340.86)
October	*	(1,833,874.86)

Regression Statistics	
Multiple R	86%
R Square	73%
Adjusted R Square	72%
ANOVA	
	df
Regression	7
Residual	112
Total	119
	t Stat
Intercept	1.23
Heating Degree Days	8.87
Cooling Degree Days	11.21
Number of Days in Month	4.42
Real Ontario GDP (chained $1997	(0.19)
April	(3.49)
May	(2.39)
October	(1.43)

Table 3.6- Updated for 3-VECC-12 g): Total System Purchases (GWh)			
Year	Actual	Predicted	% Difference
2003	964.3	986.6	2.31%
2004	989.6	973.9	-1.58%
2005	1,025.7	1,006.7	-1.85%
2006	1,022.8	981.5	-4.03%
2007	1,043.0	992.9	-4.80%
2008	1,013.4	978.4	-3.46%
2009	940.8	968.1	2.90%
2010	950.8	990.1	4.14%
2011	944.9	990.8	4.85%
2012	964.4	990.7	2.72%
2013 Weather Normal- 10 year average		984.2	

2.0 VECC – 13

Reference: Exhibit 3, Tab 2, Schedule 1, page 10

a) Please confirm whether the forecast 2013 values shown in Table 3.6 are after the manual CDM adjustment for 2013 programs.

Response: BPI confirms that the forecast 2013 values shown in Table 3.6 are after the manual CDM adjustment for 2013 programs.

b) Please provide a table that for the years 2011 and 2012 sets out:

1. The actual purchased kWh
2. The Actual HDD and CDD values for each year
3. The assumed weather normal HDD and CDD values
4. The difference between the Normal and Actual HDD values multiplied by 15,963 for each year
5. The difference between the Normal and Actual CDD values multiplied by 110,374 for each year
6. The Addition of items (1), (4) and (5) from above for each year

Response: The table below provides the requested information:

		2011	2012
1.	**Actual Purchased kWh**	**944,902,732**	**964,379,231**
2.	Actual		
	CDD	428	477
	HDD	3,648	3,215
3.	Assumed Weather Normal Values		
	CDD	373	373
	HDD	3,671	3,671
4.	Difference between Normal and Actual HDD	23	456
	HDD multiplier	15,963	15,963
	Difference *multiplier	**374,652**	**7,272,264**
5.	Difference between Normal and Actual CDD	(55)	(105)
	CDD Multiplier	110374	110374
	Difference * multiplier	**(6,094,852.28)**	**(11,547,327.88)**
6.	**Sum of items 1,4,5**	**939,182,531.45**	**960,104,166.74**

3.0 VECC – 14

Reference: Exhibit 3, Tab 2, Schedule 1, page 11

a) Please provide a schedule that for 2013 sets out:

- The projected purchases as forecast using the regression model (and indicate where in the Excel Load Forecast model this value is found)
- The adjustment for 2013 CDM programs (and indicate whether the 2,584,069 kWh value used is purchases or billed energy)
- The adjustment for losses, and
- The resulting billed kWh forecast of 919.9 GWh.

Response: The schedule below provides the requested information:

	2013 Projected Monthly Purchases	
Month	Purchased kWh Forecast	Sources:
Jan-13	84,013,819	Tab "Purchased Power Model" Cells K123:K134 for monthly values
Feb-13	77,116,200	
Mar-13	81,209,097	
Apr-13	71,735,837	
May-13	73,950,770	
Jun-13	79,836,227	
Jul-13	88,716,036	
Aug-13	85,889,548	
Sep-13	76,477,655	
Oct-13	76,232,907	
Nov-13	78,654,469	
Dec-13	83,962,411	
Total	957,794,975	
	Adjustments to Purchased Power Forecast	
Total Predicted kWh Purchases 2013 (A)	957,794,975	Tab "Purchased Power Model" Cell K148
Loss Adjustment Factor (B)	1.0383	Tab "Rate Class Energy Model" Cell F27
Billed kWh Energy Forecast C = (A)/(B)	922,461,807	Tab "Rate Class Energy Model" Cell G24
CDM Adjustment (D)	-2,584,069	Tab "Rate Class Energy Model" Cell G85
CDM-Adjusted Billed kWh Forecast (E)= (C)+(D)	919,877,738	Tab "Rate Class Energy Model" Cell O73

3.0 VECC – 15

Reference: Exhibit 3, Tab 2, Schedule 1, page 12

a) What was the actual customer count by class as of June 30, 2013?

Response: The table below provides the actual customer count by class as of June 30, 2013:

Number of Customers in June						
Year	Residential	GS<50	GS>50	Street	Sentinel	USL
2012	34,883	2,734	413	10,208	622	443
2013	35,195	2,750	412	10,232	625	440

3.0 VECC – 16

Reference: Exhibit 3, Tab 3, Schedule 1, pages 3-9

a) Please explain why there are actual sales reported to both Embedded Distributor and Standby for 2008-2012 but they are not included in the forecast developed in Tab 2, Schedule 1.

Response: The forecasts for the Embedded Distributor and Standby classes were not made using BPI's regression-based forecasting model since as explained in b), these classes do not have Purchased Power amounts associated with them.

b) Are the volumes sold to these two classes not reflected in BPI's monthly purchases and, if not, why not?

Response: The volumes sold to these two classes are not reflected in BPI's monthly purchases for the following reasons.

Embedded Distributor

The IESO bills BPI directly for kWh usage within its service territory. BPI's embedded distributor, BCP, is billed directly and separately for its own kWh purchases by the IESO based on usage measured on BCP owned meters. BPI does not purchase power for BCP, and therefore the embedded distributor is not reflected in BPI's monthly purchases.

BPI's IESO transmission charges include BCP load, and BPI uses these load values to bill BCP for the kW load charges (network and connection) for its three wholesale metering points embedded to BPI. The load values are also used to charge distribution volumetric charges.

Standby Class

Customers who have reserved standby capacity on BPI's system are billed through Standby rates at a rate to recover the costs to guarantee this capacity. There are no costs for energy or for the distribution of energy included in this charge and there is no power purchased for the standby class. The same customers who have standby power accounts have a general service account which they are billed for the distribution, transmission, regulatory and cost of power charges they incur based on the energy they consume. Any such consumption has been reflected in the monthly purchased power amounts used in the Load Forecast regression, and in the monthly billed energy amounts for the relevant General Service class.

c) What it the basis for the 2013 sales volumes shown for Embedded Distributor and Standby in Table 3.33?

Response: The 2013 sales volume of 155,806 kW for the Embedded Distributor Class has been forecast using an average of the previous 3 years' data kW billed.

The 2013 sales volume forecast of 36 000 kW of reserved capacity for the Standby Class has been developed multiplying the threshold monthly reserved capacity for BPI's standby customers (3000 kW per month), by 12 months.

3.0 VECC – 17

Reference: Exhibit 3, Tab 3, Schedule 4, page 2

a) Please explain more fully BPI's concerns regarding the privacy implications of providing Arrears Certificate.

Response: Please refer to the response to 3.0 Energy Probe-19.

b) What would give rise to BPI having to install/remove a load control device after hours?

Response: BPI would install or remove a load control device after hours only in response to a request from the customer to have the device installed or removed at that time.

3.0 VECC – 18

Reference: Appendix 2-F: Other Operating Revenue

a) How many MicroFit customers does BPI currently have and where is the associated revenue reported?

Response: At the end of September 2012, BPI had 67 MicroFIT customers. The associated revenue is reported in account 4325-Miscellaneous Service Revenue. The Test Year budget forecast for this account included a provision for MicroFit revenues. Please refer to the updated Appendix 2-F submitted in response to 3-Energy Probe-18 c) for further details.

Exhibit 4 – Operating Costs

4.0 Staff-14

Ref: Exhibit 4, Tab 1, Schedule 1, Page 1

Board staff notes that Table 4.1 contains a reconciling item to its financial statements of "OM&A contra account adjustment" for 2010 and 2011 of $373,781 and $315,364, respectively.

a) Please explain this adjustment.

Response: This adjustment is the amount that relates to the amortization on smart meters. This amount was originally in account 5705 and was transferred to account 5695. This is in line with the fixed asset continuity schedule that was filed.

b) Does this contra account continue beyond 2011?

Response: The contra account only continued to 2012. In 2012, the amount for smart meter amortization transferred to account 5695 was $321,320.

4.0 Staff-15

Ref: Exhibit 4, Tab 2, Schedule 1, Page 1

BPI states that its OM&A expenditures for 2013 are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

a) Please explain the criteria or strategy used to determine which solutions are the most appropriate and cost effective.

Response: Department managers were asked to complete their 2013 budgets with a goal of limiting increases in labour costs to those non-discretionary costs attributable to statutory obligations or changes in applicable collective agreements. No increases were to be provided for all other departmental goods and services. As this was not possible in all cases, non-discretionary exceptions were accommodated to the extent possible from other operating savings identified in the budget process.

In order to achieve the stated budget objectives, managers needed to consider their work plans, staffing levels and operational priorities. As part of this review, managers needed to establish their specific departmental strategy to achieve required outputs or service levels within the available funding. Managers used their experience and professional judgment to determine the preferred approach.

b) Please provide an example of an OM&A expenditure where this prioritization process was applied, including competing priorities and alternative solutions considered.

Response: As an example of an OM&A expenditure where this prioritization process was applied, BPI advises that the first version of the 2013 budget included a new hire, an additional Settlement Energy and Smart Metering Officer [SESMO] position in the Metering and Settlement Department. Because of the greater identified need for additional resourcing in the Customer Services Department as discussed above in response to Board Staff interrogatory 2-Staff-9, the proposed SESMO position was removed from the 2013 budget.

4.0 Staff-16

Ref: Exhibit 1, Tab 2, Schedule 2, Page 1 &
Exhibit 4, Tab 2, Schedule 1, Page 1

BPI states that budget requests must be consistent with the financial parameters expected over a five year period.

a) Please provide the financial parameters for the 5 year period underlying the 2013 budget.

Response: As BPI's financial planning is based on a budget year plus four forecast years, the Company's budget request in the test year must result in a sustainable financial program over the five year time horizon. Among the parameters considered in the development of the financial plan are the following:

- BPI should maintain working capital at a level that is two times the current ratio;
- BPI should maintain a debt level in keeping with its capital structure policy which specifies a maximum debt guideline of 57% debt being a combination of short- and long-term debt;
- The financial plan must ensure BPI is compliant with the debt covenants specified by its lenders;
- Cash flows from operations need to be sufficient to provide for the funding the planned capital program and scheduled debt repayments; and
- The financial plan should provide for a stable dividend stream in keeping with the dividend policy

4.0 Staff-17

Ref: Exhibit 4, Tab 2, Schedule 2, Page 1

BPI states that its customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective.

a) Please describe the methodology by which customer responsiveness and system reliability are monitored.

Response: Customer responsiveness and service reliability statistics are compiled monthly and summarized quarterly. Those results are compared to performance in previous years and also to the standards set by the Board. Outages longer than 20 minutes in duration are identified, including the reason for the outages and the number of customers affected.

b) Please describe the reporting mechanism for the monitoring results. To whom are the results reported and how often?

Response: Customer responsiveness and system reliability are monitored by the appropriate department head. Given the decline in the telephone accessibility statistics as discussed above in response to Board Staff interrogatory 2-Staff-9, those customer responsiveness statistics are monitored by the department head and the Chief Executive Officer.

c) What mechanisms are in place to ensure that the monitoring results are acted upon?

Response: That the applicable department head monitors customer responsiveness and system reliability on a monthly basis ensures that changes in trends are acted upon.

4.0 Staff-18

Ref: Exhibit 4, Tab 2, Schedule 3, Pages 17 & 22

BPI has identified an increase in transformer inventory as a cost driver for changes between 2009 and 2010, as well as between 2011 and 2012.

a) Please explain why transformer inventory has been categorized as an OM&A cost, rather than a capital cost.

Response: Transformer inventory was categorized as an OM&A cost because these costs were believed to be related to maintenance. Upon further review, BPI notes that these costs should have been categorized as capital costs and not as OM&A.

b) If transformer inventory is a capital cost, please provide an explanation for the $152k OM&A increase in 2010 and $202k in 2012.

Response: Transformer inventory costs were incorrectly mapped to account 5160 as maintenance costs. The $152,000 increase in 2010 as compared to 2011 is due to 12 transformers being placed in inventory at a total cost of $147,860. The $202,000 increase in 2012 compared to 2011 is a result of 23 transformers placed in inventory at a total cost of $161,856. In addition to this, 2011 is lower than 2010 and 2012 because a transformer at a cost of $62,439 was removed from inventory but the offset of when the transformer was placed in inventory was not recorded.

4.0 Staff-19

Ref: Exhibit 4, Tab 2, Schedule 3, Appendix 2-J

BPI has included a cost driver in 2012 of $217k for amounts owed in relation to a retirement.

a) Please explain the components of this retirement amount.

Response: This response has been intentionally redacted as the amount relates to a payment to an identifiable individual and constitutes personal information within the meeting of *FIPPA.*

b) Are similar payments made to all retirees?

Response: Similar payments are not made to all retirees.

c) If so, please provide a forecast of expected retirements over 5 years and estimates of amounts to be paid over that period.

Response: Please refer to the response to Board Staff Interrogatory 4-Staff-19b.

4.0 Staff-20

Ref: Exhibit 4, Tab 2, Schedule 5, Page 4
& Appendix 2-K

BPI's Appendix 2-K includes a mix of actual and assumed FTEEs to calculate employee costs.

a) Please provide a revised Appendix 2-K that removes all estimates of services provided and only includes BPI employees for the years 2008 actual to 2013 test year.

Response: Please refer to the response to 4.0-Staff-20c

b) In the above requested table, please ensure that salary, wages, benefits and overtime amounts reflect only the amounts paid to BPI employees, and do not reflect amounts paid to service providers.

Response: Please refer to the response to 4.0-Staff-20c

c) For the 2012 bridge year, please include the transferred employees on a prorated basis (I.e. 20 FTEEs from April 1 = 20 (9/12) = 15).

Response: BPI provides the following update to Appendix 2-K which includes the adjustments requested in sections a), b) and c)

Appendix 2-K*
Employee Costs

Please Note: For the years 2008-2011, BPI had only 1 FTE (as shown) consequently all of the employee costs are directly attributable to one individual and constitute confidential information under MFIPPA.

	Last Rebasing Year (2008 Board-Approved)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Employees (FTEs including Part-Time)[1]							
Executive		1.00	1.00	1.00	1.00	4.75	5.00
Management	$ -	$ -	$ -	$ -	$ -	8.50	12.00
Non-Union	$ -	$ -	$ -	$ -	$ -	3.00	5.00
Union	$ -	$ -	$ -	$ -	$ -	26.84	38.65
Total		1.00	1.00	1.00	1.00	43.09	60.65
Number of Part-Time Employees							
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ 7	$ 3
Total	-	-	-	-	-	7	3
Total Salary and Wages							
Executive		[redacted]				$ 604,684	$ 482,372
Management						$ 716,177	$ 1,341,844
Non-Union						$ 191,666	$ 433,903
Union						$ 1,685,059	$ 2,807,591
Total	$ -	[redacted]				$ 3,197,587	$ 5,065,710
Current Benefits							
Executive		[redacted]				$ 105,494	$ 111,754
Management						$ 178,700	$ 241,629
Non-Union						$ 44,815	$ 73,138
Union						$ 415,814	$ 597,699
Total	$ -	[redacted]				$ 744,822	$ 1,024,219
Accrued Pension and Post-Retirement Benefits							
Executive						$ 223,955	$ 10,653
Management						$ 12,518	$ 25,567
Non-Union						$ 5,216	$ 10,653
Union						$ 40,800	$ 61,128
Total						$ 302,001	$ 108,001
Executive	$ -	[redacted]				$ 329,449	$ 122,407
Management	$ -	$ -	$ -	$ -	$ -	$ 191,218	$ 267,196
Non-Union	$ -	$ -	$ -	$ -	$ -	$ 50,031	$ 83,791
Union	$ -	$ -	$ -	$ -	$ -	$ 456,614	$ 658,827
Total	$ -	[redacted]				$ 1,046,823	$ 1,132,220
Total Compensation (Salary, Wages, & Benefits)							
Executive	$ -	[redacted]				$ 934,133	$ 604,779
Management	$ -	$ -	$ -	$ -	$ -	$ 907,395	$ 1,609,040
Non-Union	$ -	$ -	$ -	$ -	$ -	$ 241,697	$ 517,694
Union	$ -	$ -	$ -	$ -	$ -	$ 2,141,673	$ 3,466,418
Total	$ -	[redacted]				$ 4,244,410	$ 6,197,930
Compensation - Average Yearly Base Wages							
Executive		[redacted]				$ 127,302	$ 96,474
Management						$ 84,256	$ 111,820
Non-Union						$ 62,948	$ 86,781
Union						$ 59,929	$ 70,489
Total						$ 72,365	$ 82,152
Compensation - Average Yearly Overtime							
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ 940	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ 2,852	$ 2,153
Total	$ -	$ -	$ -	$ -	$ -	$ 1,842	$ 1,372
Compensation - Average Yearly Incentive Pay							
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Compensation - Average Yearly Benefits							
Executive		$ -	$ -	$ -	$ -	$ 69,358	$ 24,481
Management	$ -	$ -	$ -	$ -	$ -	$ 22,496	$ 22,266
Non-Union	$ -	$ -	$ -	$ -	$ -	$ 16,677	$ 16,758
Union	$ -	$ -	$ -	$ -	$ -	$ 17,012	$ 17,046
Total	$ -	[redacted]				$ 24,294	$ 18,668
Total Compensation	$ -	[redacted]				$ 4,224,898	$ 6,197,930
Total Compensation Capitalized (CGAAP)						$ 587,397	$ 872,991
Total Compensation Charged to OM&A (CGAAP)	$ -	[redacted]				$ 3,637,501.07	
Total Compensation Capitalized (MIFRS)							
Total Compensation Charged to OM&A (MIFRS)					[redacted]	$ 4,224,898.07	$ 6,197,930.07

d) In a separate table, please provide average base wages, overtime, incentive pay and benefits both on a pre- and post-transfer basis, using the same FTEE categories as contained in Appendix 2-K.

2012 Average Compensation Paid: Pre- and Post- Transfer

Please note: before the transfer of employees, BPI had only one FTE . Consequently, all employee costs are directly attributable to this employee and constitute confidential information under MFIPPA

	pre-transfer	post-transfer
Compensation - Average Yearly Base Wages		
Executive	[redacted]	$ 127,302
Management	$ -	$ 84,256
Non-Union	$ -	$ 62,948
Union	$ -	$ 59,929
Total	$ -	$ 72,365
Compensation - Average Yearly Overtime		
Executive	$ -	$ -
Management	$ -	$ -
Non-Union	$ -	$ 940
Union	$ -	$ 2,852
Total	$ -	$ 1,842
Compensation - Average Yearly Incentive Pay		
Executive	$ -	$ -
Management	$ -	$ -
Non-Union	$ -	$ -
Union	$ -	$ -
Total	$ -	$ -
Compensation - Average Yearly Benefits		
Executive	[redacted]	$ 22,209
Management	$ -	$ 21,023
Non-Union	$ -	$ 14,938
Union	$ -	$ 15,492
Total	$ -	$ 17,285

1

e) Please provide the following information on year-end headcount for BPI employees:

Response:

	2011 Year End	2012 Transfers	Add/Delete 2012	Add/Delete 2013	Planned 2013 Year End
Operations and Maintenance	0	17	0	0	17
Inventory Management	0	3	0	0	3
Metering and Settlement	0	6	0	-1	5
Engineering and Construction	0	9	0	1	10
Customer Service	0	9	4	1	14
CDM	0	2	0	0	2
Finance Support	0	3	0	1	4
Regulatory and Admin	1	5	0	0	6
TOTAL	1	54	4	2	61

The table above sets out the Year- End headcount information requested. Please note that the numbers represent headcount, where a Part Time employee counts as “1”.

f) Please provide the evidence reference describing each add/delete (other than transfers) shown in the table above. If the additions have not been described in the evidence, please provide a separate description.

Response: BPI provides the following table in response to question f):

	Add/ Delete 2012:	
Headcount impact	Description	Application Reference
	Customer Services *	
1	New Hire May 2012 to fill a retirement before April 1 Transfer	E4/T2/S5 p 13 lines 5-8
1	Full Time Hire August 2012	E4/T2/S5 p 14 line 1
1	Part Time Hire December	E4/T2/S5 p 14 line 1-2
1	Contract Hire November	E4/T2/S5 p 14 line 1
	Operations and Maintenance	
-1	Director of Operations retired; position was absorbed within existing Senior Leadership Team; no replacement hire.	E4/T2/S5/ p14 lines 14-16
-1	One Foreman Retired; replaced through promotion of a linesman, creating a linesman vacancy for 2012.	E4/T2/S5/ p12 lines 21-22
	Add/ Delete 2013	
Headcount impact	Description	Application Reference
	Customer Services *	
1	Planned new Customer Services Representative	E4/T2/S5/ p16 lines 19-20
	Operations and Maintenance	
1	Planned hire of a linesman to replace 2012 vacancy	E4/T2/S5/ p15 lines 1-3
	Finance Support *	
1	Planned hire of a Financial Analyst*	E4/T2/S5/ p16 line 20
	Engineering and Construction	
1	Planned hire of a Electrical Design Technologist	E4/T1/S5 p16 line 20
*	*Please note that at BPI was transferred 3 vacant positions: 2 in Customer Services and 1 in Finance Support.*	*e4/T2/S5 p13 lines 22-23*

4.0 Staff-21

Ref: Exhibit 4, Tab 1, Schedule 1, Page 5

BPI states that although CDM employees are included in the FTEE count, these costs are not recovered in rates.

a) How are the CDM employee costs recovered?

Response: The CDM labour costs are recovered from the Ontario Power Authority. These revenues are tracked in account 4375- Revenues from Non-Utility Operations and the labour costs are tracked in 4380- Expenses from Nun-Utility Operations.

4.0 Staff-22

Ref: Exhibit 4, Tab 2, Schedule 5, Page 4 &
Exhibit 4, Tab 2, Schedule 6, Appendix B

BPI states that it is unable to identify the resources used to deliver services, nor the amount of time spent to provide the services for the years 2008 to 2012. BPI states that with the new SSA Agreement effective January 1, 2013, this information has improved.

a) Please indicate the specific provisions in the January 1, 2013 SSA Agreement that will provide BPI with better information about resource inputs to services purchased from its affiliate.

Response: The schedules to the new SSA effective January 1, 2013 set out objective mechanisms that measure the amount of services used by BPI and drive the pricing of services. The specific drivers for each service with the reference to the SSA are:

- Accounts Payable – number of line items processed for BPI invoices as a percentage of total line items processed [Schedule A-1];
- Payroll – yearly average BPI FTE's as a percentage of total FTEs [Schedule A-2];
- Purchasing – time spent based on time docketing plus actual out-of-pocket expenses [Schedule A-3];
- Human Resources Administration and Health and Safety -- yearly average BPI FTE's as a percentage of total FTEs [Schedule A-4];
- Employment and Labour Relations Services -- time spent based on time docketing [Schedule A-4];
- Information Technology Administrative Services including core network services, financial information system services including administration – number of BPI users as a percentage of total users of core network and financial information system services [Schedule A-5];

- Information systems specific to Brantford Power – time spent with 100% of staff time dedicated to BPI systems support and maintenance plus actual out-of-pocket expenses [Schedule A-5];
- Legal and Real Estate Services -- time spent based on time docketing plus actual out-of-pocket expenses [Schedule A-6];
- Postage Services – pieces of outgoing mail processed for BPI excluding customer invoices [Schedule A-8];
- Telephone Services – number of BPI telephone lines as a percentage of total telephone system lines [Schedule A-9];
- Insurance and risk Management Services – value of BPI insurance premiums as a percentage of total insurance premiums managed plus cost of insurance premiums [Schedule A-10];
- Facility Asset Management – Repair and Maintenance based on square footage of BPI occupied space; administration costs based on estimated time spent; rent based on market rate applied to square footage of BPI occupied space [Schedules A-12, A-13 and A-14];
- Tree trimming services – based on percentage of BPI work orders plus actual administrative costs [Schedule A-15];
- Mail Run – cost per delivery based on market rate [Schedule A-7];
- Records management – cost per service utilized based on market rates [Schedule A-11] yearly average BPI FTE's as a percentage of total FTEs.

b) Please describe the methodology proposed by BPI to assess the reasonableness of the cost and level of services under the new agreement.

Response: The new SSA provides for monthly invoicing with two semi-annual true-ups. BPI staff reviews monthly invoices for reasonableness and appropriateness. Semi-annual true-ups will also be reviewed by BPI staff for appropriateness and reasonableness. In the event of a dispute of the monthly invoice, BPI under the new SSA may provide written notice to the City of a dispute. Section 5.4 of the new SSA states that;

> *Each of BPI and the City will provide to the other whatever additional reports and information relating to the Services provided under this Agreement which the other may reasonably request.*

When BPI staff, in its review of the monthly invoices have questions about the costs and levels of services, BPI staff will request additional reports and information from the City with respect to those charges as provided for in clause 5.4.

4.0 Staff-23

Ref: Exhibit 4, Tab 2, Schedule 5, Page 14

BPI has described the change in compensation for its union employees on pps 12-14. The final statement of this description states that the annual economic adjustment for <u>non-union</u> employees for 2012 was 1.25%.

a) Please provide the annual adjustment for union employees for 2012.

Response: The annual adjustment for CUPE employees was 1.25% effective April 2012. For IBEW, the Annual Adjustment was 2%, effective June 2012 with an additional $0.11 hourly rate increase to the Line and Meter Technician positions.

4.0 Staff-24

Ref: Exhibit 4, Tab 2, Schedule 5, Page 17

BPI states that it is currently in negotiation with IBEW and is not in a position to discuss the economic adjustment for 2013.

a) What is the economic adjustment for 2013 for CUPE?

Response: The annual adjustment for CUPE is 1.5%, effective April 1 2013 to March 31 2014.

b) Is BPI in a position to provide that adjustment for IBEW at this time? If so, what is the adjustment?

Response: The adjustment for IBEW for 2013 is 1% effective June 2, 2013, with an additional $0.35 hourly rate increase to the Line and Meter Technician positions, followed by a 1% increase effective December 1, 2013.

4.0 Staff-25

Ref: Exhibit 4, Tab 2, Schedule 6, Page 7

BPI shows an unexplained variance of $81,360 for legal services in Table 4.32.

a) Please provide an explanation for this variance.

Response: In 2008, the monthly base fee amounts to $57,666 for the year. This amount had also included a 10% mark-up of $5,242 which is no longer charged to BPI.

Other services required by the legal department included assistance with an OIPC (Ontario Infrastructure Projects Corporation) financing agreement amounting to $7,332; partnership discussions with another utility at a cost of $16,039; work on BPI's 2008 rate application which had been coded to the incorrect account (should have been in account 5665) in the amount of $12,353 and preparation of an opinion of BPI's structure in relation to the Affiliate Relationship Code in the amount of $42,970. The total of these services is $78,693.

Legal services provided in the SSA Agreement are lower in 2013 because BPI does not have any significant projects in the 2013 work plan requiring internal out-of-pocket legal costs. As well, a time-docketing system has been implemented to track actual staff time spent on BPI activities.

4.0 Staff-26

Ref: Exhibit 4, Tab 3, Schedule 1, Page 1 &
Exhibit 6, Tab 1, Schedule 1, Page 3

BPI's Exhibit 4 does not contain a discussion of property taxes, although the Revenue Deficiency determination shows an increase of 136% between 2012 and 2013.

a) Please explain the increase in property taxes between 2012 and 2013.

Response: Please refer to the response to 1.0 Energy Probe-4 above.

LRAM

4.0 Staff-27

Ref: E4, T4, S1, p 2 of 2, Table 4.52 &
Appendix G, LRAM Third Party Report, Page 3 &
Guideline for Electricity Distributor Conservation and Demand Management (EB-2012-0003)

LRAM for pre-2011 CDM Activities:

BPI has requested approval of an LRAM amount of $118,455.70 related to the persistence in 2011 of its 2006-2010 CDM Programs. BPI further notes that it should also be eligible for the 2006-2010 program persistence into 2012 and 2013 as well, but has only requested the persisting 2011 LRAM amount at this time to adhere to the Board's direction to refrain from prematurely requesting recovery of future year LRAM amounts.

The Board's CDM Guidelines state at Section 13.6 that "lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time.

a) Please discuss if BPI's 2013 load forecast will incorporate persisting CDM effects from 2006-2010 CDM Programs.

Response: Yes, BPI's 2013 load forecast as filed will incorporate persisting CDM effects from 2006-2010 CDM Programs.

b) Please discuss why BPI feels it is appropriate to recover 2013 persisting LRAM amounts from 2006-2010 CDM Programs given the Board's direction to incorporate these amounts in the load forecast at the time of rebasing.

Response: BPI submits that it is appropriate to recover 2013 persisting LRAM amounts from 2006-2010 CDM programs until the rates set in this Application are in effect. BPI has requested an effective date of November 1st 2013 for its rates in this Application. BPI intends to claim LRAM accruing until its effective date when the 2013 OPA Final results become available. BPI believes this is the appropriate course of action, consistent with the CDM Guidelines Section 13.6 as well as the Board's direction to refrain from prematurely requesting recovery of future year LRAM amounts.

4.0 Staff-28

Ref: Exhibit 4, Tab 4, Schedule 1, Page 2 of 2, Updated August 14, 2013 & Appendix G, LRAM Third Party Report, Pages 4-6

LRAMVA for 2011-2014 CDM Activities:

BPI has requested approval of its 2011 LRAMVA amount of $35,846.19 which represents the lost revenues associated with its 2011 CDM Programs. BPI has not requested approval of LRAMVA amounts associated with 2012 CDM Programs at this time as these amounts are only estimates.

a) Please confirm that BPI is only requesting approval of $35,846.91 which represents the LRAMVA amount for its 2011 CDM Programs in 2011.

Response: BPI confirms it is only requesting approval of $35,846.91 which represents the LRAMVA amount for its 2011 CDM Programs in 2011.

b) Please confirm that BPI's net savings totals from which its 2011 LRAMVA amount was derived are 4,515,479 kWh and 1,230 kW. If BPI used different net savings amounts to calculate its 2011 LRAMVA amount, please discuss the rationale for doing so and provide the inputs that went into this calculation.

Response: BPI confirms these are the amounts that were used in the calculations. They appear in the BPI's updated LRAM and LRAMVA report, updated in the evidence on August 15, which can be found on page 8/15 at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/406266/view/ BPI notes that there may be small variances from these figures which are due to rounding.

c) Please confirm that BPI is requesting recovery of its LRAMVA amount over a one-year period, similar to its LRAM amount discussed above.

Response: BPI confirms it is requesting recovery of its LRAMVA over a one-year period.

4.0 Energy Probe-20

Ref: Exhibit 4, Tab 1, Schedule 1

a) Please confirm that Table 4.2 includes actual costs for 2012. If this cannot be confirmed, please provide a revised Table 4.2 that includes actual data for 2012.

Response: Table 4.2 does not already include actual costs for 2012. A revised table follows.

Description	2008 Board Approved	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge	2012 Actual	2013 Test
Operations	998,220	1,018,908	1,057,112	1,008,391	1,076,343	1,111,298	1,322,296	1,576,506
Maintenance	1,725,334	1,757,147	1,723,356	1,681,173	1,456,583	1,802,869	1,428,085	2,033,090
Billing & Collecting	2,107,836	1,978,917	2,205,690	2,166,453	2,045,182	2,208,332	2,295,837	2,863,215
Community Relations	127,331	113,237	127,829	131,379	115,623	169,137	160,639	232,777
Administrative & General Expense (Includes Special Purpose Charge)	2,548,053	2,825,788	2,614,082	2,971,323	2,318,604	2,521,038	2,699,643	2,498,437
Total OM&A Expenses	**7,506,774**	**7,693,996**	**7,728,069**	**7,958,720**	**7,012,336**	**7,812,674**	**7,906,500**	**9,204,025**
Less Special Purpose Charge				376,534				
Total Recoverable OM&A Expenses	**7,506,774**	**7,693,996**	**7,728,069**	**7,582,186**	**7,012,336**	**7,812,674**	**7,906,500**	**9,204,025**
Year over Year % Variance		2.5%	0.4%	3.0%	-11.9%	11.4%	1.2%	17.8%
GDP-IPI		2.1%	2.3%	1.3%	1.3%	2.0%	2.0%	1.6%

b) Please provide a table in the same level of detail as Table 4.5 that shows the most recent year-to-date actual expenses available for 2013, along with the figures for the corresponding figures for 2012.

Response: Please find below a table reflecting OM&A totals for 2012 year-to-date September and 2013 year-to-date September.

OM&A: 2012 Actual vs 2013 Year-to-Date				
Description	2012 YTD	2013 YTD	Variance $	Variance %
	September	September		
Operations	947,383	1,117,814	170,431	15.2%
Maintenance	964,323	1,410,291	445,969	31.6%
Billing & Collecting	1,714,686	1,975,413	260,727	13.2%
Community Relations	109,070	37,467	(71,603)	-191.1%
Administrative & General Expense	1,697,362	2,038,468	341,106	16.7%
Total Recoverable OM&A Expenses	**5,432,823**	6,579,453	1,146,630	17.4%

c) Please provide the source of the 1.7% increase in the GDP-IPI shown in Table 4.2 for 2011. Please confirm that the Board`s figure used for May 1, 2011 increases was 1.3%.

Response: Table 4.2 has been corrected. The GDP-IPI for the year 2011 should have been 1.3%.

For Rates Effective	2007	2008	2009	2010	2011	2012	2013
May 1st	1.9	2.1	2.3	1.3	1.3	2.0	1.6
Jan 1st						1.7	2.2

Source: Statistics Canada, GDP-IPI (FDD)

4.0 Energy Probe-21

Ref: Exhibit 4, Tab 2, Schedule 3

Please update Tables 4.13 through 4.17 to reflect actual data for all of 2012.

Response: The following tables reflect actual data for 2012.

Table 4.13

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations								
5005	Operation Supervision and Engineering	$ 244,352	$ 332,926	$ 335,123	$ 327,414	$ 226,223	$ 387,915	$ 273,250
5010	Load Dispatching	$ 16,375	$ 35,700	$ 49,739	$ 31,918	$ 45,927	$ 43,685	$ 114,745
5012	Station Buildings and Fixtures Expense	$ 36,464	$ 33,982	$ 29,812	$ 25,755	$ 29,252	$ 25,449	$ 29,322
5014	Transformer Station Equipment - Operation Labour	$ 6,205	$ 5,596	$ 7,009	$ 15,354	$ 7,906	$ 6,611	$ 24,787
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 51,220	$ 67,308	$ 72,587	$ 96,171	$ 75,365	$ 79,709	$ 102,609
5016	Distribution Station Equipment - Operation Labour	$ 1,959	$ 2,387	$ 1,277	$ 4,208	$ 1,743	$ 1,260	$ 1,962
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 3,612	$ 1,512	$ 1,134	$ 1,155	$ 400	$ 357	$ 520
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 3,019	$ 2,523	$ 1,771	$ 1,928	$ 985	$ -	$ 1,962
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 13,806	$ 6,293	$ 6,026	$ 1,976	$ 10,893	$ 11,333	$ 12,752
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5035	Overhead Distribution Transformers - Operation	$ 14,800	$ 8,986	$ 9,393	$ 3,868	$ 2,989	$ 907	$ 5,154
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 1,043	$ 139	$ 1,671	$ 1,178	$ 670	$ 27	$ -
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 18,921	$ 5,625	$ 10,635	$ 6,267	$ 9,508	$ 10,661	$ 11,990
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5055	Underground Distribution Transformers - Operation	$ 3,290	$ 1,387	$ 1,736	$ 685	$ 665	$ 52	$ -
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5065	Meter Expense	$ 452,578	$ 285,758	$ 265,762	$ 363,773	$ 464,155	$ 548,618	$ 593,094
5070	Customer Premises - Operation Labour	$ 5,979	$ 315	$ 334	$ 461	$ 710	$ 430	$ 5,292
5075	Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5085	Miscellaneous Distribution Expenses	$ 118,312	$ 253,078	$ 186,167	$ 182,823	$ 221,832	$ 182,710	$ 329,209
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 6,285	$ 13,596	$ 19,983	$ 6,869	$ 7,343	$ 6,711	$ 25,403
5096	Other Rent	$ -	$ -	$ 8,233	$ 4,540	$ 4,732	$ 15,862	$ 44,455
Total - Operations		$ 998,220	$ 1,057,112	$ 1,008,391	$ 1,076,343	$ 1,111,298	$ 1,322,296	$ 1,576,506

Table 4.14

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year
Maintenance								
5105	Maintenance Supervision and Engineering	$ 280,966	$ 304,849	$ 325,801	$ 307,486	$ 432,478	$ 204,823	$ 499,599
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 3,970	$ 431	$ 1,031	$ 1,892	$ 1,559	$ 930	$ 2,158
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5114	Maintenance of Distribution Station Equipment	$ 16,206	$ 9,409	$ 10,704	$ 5,684	$ 6,747	$ 1,203	$ 9,805
5120	Maintenance of Poles, Towers and Fixtures	$ 153,188	$ 135,624	$ 57,113	$ 44,139	$ 32,442	$ 59,222	$ 75,414
5125	Maintenance of Overhead Conductors and Devices	$ 194,468	$ 128,912	$ 109,023	$ 196,827	$ 184,573	$ 157,869	$ 242,022
5130	Maintenance of Overhead Services	$ 201,225	$ 200,498	$ 229,757	$ 218,602	$ 192,135	$ 162,683	$ 247,604
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 333,592	$ 399,183	$ 396,203	$ 348,542	$ 415,898	$ 391,195	$ 499,535
5145	Maintenance of Underground Conduit	$ 66,733	$ 75,395	$ 38,898	$ 54,614	$ 52,661	$ 55,273	$ 56,902
5150	Maintenance of Underground Conductors and Devices	$ 111,669	$ 138,560	$ 89,626	$ 71,835	$ 70,158	$ 49,277	$ 82,311
5155	Maintenance of Underground Services	$ 204,053	$ 221,815	$ 143,095	$ 138,372	$ 109,059	$ 109,014	$ 124,877
5160	Maintenance of Line Transformers	$ 159,264	$ 108,654	$ 279,921	$ 68,591	$ 305,006	$ 236,456	$ 192,863
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5175	Maintenance of Meters	$ -	$ 26	$ -	$ -	$ 153	$ 141	$ -
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total - Maintenance		$ 1,725,334	$1,723,356	$1,681,173	$1,456,583	$1,802,869	$1,428,085	$2,033,090

Table 4.15

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year
Billing and Collecting								
5305	Supervision	$ 135,049	$ 175,292	$ 181,121	$ 161,326	$ 223,136	$ 258,214	$ 292,372
5310	Meter Reading Expense	$ 371,227	$ 440,325	$ 402,412	$ 354,422	$ 274,993	$ 408,268	$ 240,556
5315	Customer Billing	$ 466,741	$ 542,936	$ 555,894	$ 495,101	$ 542,425	$ 586,654	$ 964,616
5320	Collecting	$ 300,111	$ 350,585	$ 362,242	$ 322,653	$ 359,916	$ 305,480	$ 536,496
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5330	Collection Charges	$ 2,251	$ 548	$ 454	$ 833	$ 1,000	$ 12,413	$ 500
5335	Bad Debt Expense	$ 183,090	$ 257,772	$ 211,527	$ 307,532	$ 300,000	$ 163,887	$ 306,000
5340	Miscellaneous Customer Accounts Expenses	$ 649,367	$ 438,231	$ 452,803	$ 403,316	$ 506,862	$ 560,922	$ 522,675
Total - Billing and Collecting		$ 2,107,836	$2,205,690	$2,166,453	$2,045,182	$2,208,332	$2,295,837	$2,863,215

Table 4.16

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year
Community Relations								
5405	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5410	Community Relations - Sundry	$ 114,588	$ 119,559	$ 113,351	$ 106,211	$ 156,330	$ 148,571	$ 152,526
5415	Energy Conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5420	Community Safety Program	$ 12,743	$ 8,270	$ 18,029	$ 9,412	$ 12,807	$ 12,068	$ 19,051
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,200
5505	Supervision	$ -	$ -	$ -	$ -	$ -		$ -
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -		$ -
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -		$ -
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -		$ -
Total - Community Relations		$ 127,331	$ 127,829	$ 131,379	$ 115,623	$ 169,137	$ 160,639	$ 232,777

Table 4.17

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 392,793	$ 388,053	$ 403,908	$ 319,673	$ 533,369	$ 540,492	$ 729,401
5610	Management Salaries and Expenses	$ 662,071	$ 397,061	$ 402,930	$ 302,363	$ 340,676	$ 253,135	$ 384,158
5615	General Administrative Salaries and Expenses	$ 664,697	$ 867,658	$ 917,874	$ 884,744	$ 875,651	$ 949,117	$ 582,990
5620	Office Supplies and Expenses	$ 48,202	$ 65,075	$ 57,260	$ 51,082	$ 58,468	$ 61,555	$ 80,250
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5630	Outside Services Employed	$ 164,324	$ 39,291	$ 58,600	$ 127,715	$ 138,735	$ 100,792	$ 220,000
5635	Property Insurance	$ -	$ 99,320	$ 74,245	$ 99,678	$ 100,861	$ 100,723	$ 133,133
5640	Injuries and Damages	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5645	OMERS Pensions and Benefits	$ 101,036	$ 244,532	$ 215,393	$ 175,099	$ 302,000	$ 433,800	$ 108,000
5646	Employee Pensions and OPEB	$ -	$ -	$ -	$ -	$ -	$ 57,569	$ -
5647	Employee Sick Leave	$ -	$ -	$ -	$ -	$ -	$ 125,787	$ -
5650	Franchise Requirements	$ 49,316	$ 50,606	$ 53,427	$ 53,775	$ 57,569	$ 29,123	$ 59,000
5655	Regulatory Expenses	$ 196,822	$ 284,560	$ 184,346	$ 120,735	$ 135,500	$ 168,325	$ 144,500
5660	General Advertising Expenses	$ 23,802	$ 20,789	$ 27,398	$ 15,894	$ 13,600	$ -	$ 40,000
5665	Miscellaneous General Expenses	$ 171,754	$ 119,196	$ 84,705	$ 151,291	$ 8,341	$ -	-$ 1,995
5670	Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5672	Lease Payment Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5675	Maintenance of General Plant	$ 54,927	$ -	$ -	$ -	$ -	$ -	$ -
5680	Electrical Safety Authority Fees	$ 18,309	$ 16,129	$ 16,167	$ 16,013	$ 16,400	$ 16,305	$ 19,000
5681	Special Purpose Charge Expense	$ -	$ -	$ 376,534	$ -	$ -	$ -	$ -
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ 51,566	$ 51,566	$ 51,758	$ 60,000	$ 56,177	$ -
5695	OM&A Contra Account	$ -	-$ 29,756	$ 46,971	-$ 51,215	-$ 120,132	-$ 193,256	$ -
6205	Donations	$ -				$ -	$ -	
6205	Donations, Sub-account LEAP Funding	$ -	$ -	$ -	$ -		$ -	
Total - Administrative and General Expenses		$ 2,548,053	$2,614,082	$2,971,323	$2,318,604	$2,521,038	$2,699,643	$2,498,437

4.0 Energy Probe-22

Ref: Exhibit 4, Tab 2, Schedule 4

a) Please show the amount included in account 1556 related to smart meters in each of 2008 through 2013.

Response: The table below shows the amount included in account 1556 related to smart meters from 2008 through 2013.

2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Forecast	Total
-	$ 5,142	$ 22,585	$ 51,215	$ 193,256	187,477	$ 459,675

b) Please confirm that BPI is proposing to recover the smart meter related OM&A expenses in account 1556 at the end of 2012 through a rate rider.

Response: The table below shows the amount of smart meter related expenses included in the 5000 series accounts from 2008 through 2013.

		2008	2009	2010	2011	2012	2013
5065	Meter Expense	$ 19,371.22	$ 22,181.57	$ (46,970.78)	$ 28,433.28	$ 25,592.72	$ 12,652.95
5310	Meter Reading	$ -	$ -	$ -	$ -	$ 144,028.60	$ 127,783.20
5615	Admin & General	$ -	$ 7,574.25	$ -	$ 22,782.01	$ 23,635.03	$ 40.71
5695	Smart Meter OM&A Contra	$ (19,371.22)	$ (29,755.82)	$ 46,970.78	$ (51,215.29)	$ (193,256.35)	$ -
		$ -	**$ -**	**$ -**	**$ -**	**$ -**	**$ 140,476.86**

c) Please conform that BPI has not included any smart meter related costs from account 1556 in the actual 2012 OM&A figures. If this cannot be confirmed, please indicate what costs from account 1556 have been included in the 2012 costs.

Response: BPI confirms that its proposed recovery of smart meter related OM&A expenses in account 1556 at the end of 2012 through a rate rider.

d) Has BPI included any of the amounts in account 1556 at the end of 2012 for which it is seeking recovery in the test year OM&A expenses? Please confirm that the 2013 test year revenue requirement does not include any amounts previously included in account 1556.

Response: BPI confirms there are no smart meter related costs from account 1556 in the actual 2012 OM&A figures

e) Has BPI included any of the amounts in account 1556 at the end of 2012 for which it is seeking recovery in the test year OM&A expenses? Please confirm that the 2013 test year revenue requirement does not include any amounts previously included in account 1556.

Response: BPI has not included any amounts in account 1556 at the end of 2012 for which it is seeking recovery in the test year OM&A expenses. BPI also confirms that its 2013 test year revenue requirement does not include any amounts previously included in account 1556.

4.0 Energy Probe-23

Ref: Exhibit 4, Tab 2, Schedule 8

a) Given the BPI appears to have used the half year rule for depreciation in Tables 4.36, 4.37 and 4.38, combined with the statement at page 1 that it does not apply the half year rule for financial reporting purposes, mean that BPI has two sets of continuity schedules (one for financial reporting and one for regulatory reporting) that will continue to diverge over time? If not, please explain.

Response: BPI does not have two sets of continuity schedules. The continuity schedules in Appendix 2 provided by the OEB had the formula for the half year rule hard coded in. BPI did not start using the half year rule until 2013 with the change in the useful lives, in accordance with BPI's accounting policy.

b) Table 4.38 does not appear to be correct in that the depreciation expense calculated for 2013 is a fraction of the $3,157,530 shown in the fixed asset continuity schedule and replicated in this table at column (l). Please provide a complete Table 4.38.

Response: Please find a corrected version of Table 4.38. A correction was also made to Table 4.37. Both tables have been updated and refiled in BPI's Chapter 2 Appendices.

Table 4.37

Used this tab for the 2013 "MIFRS" Depreciation calculation
2013 is reported under CGAAP but BPI is aligning useful
lives and componentization with MIFRS

Date:

Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 296,469.00	$ 310,000.00	3.27	5.00	20.00%	$ 90,663.30	$ 31,000.00	$ 121,663.30	$ 121,073.62	$ 589.68	$ 62,000.00		$ 152,663.30
1612	Land Rights (Formally known as Account 1906)	$ 63,406.42	$ -	49.00	50.00	2.00%	$ 1,294.01	$ -	$ 1,294.01	$ 1,294.00	$ 0.01	$ -		$ 1,294.01
1805	Land	$ 181,960.63	$ -		-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1806	Land Rights	$ -	$ -		-					$ -	$ -	$ -		
1808	Buildings	$ 969,199.81	$ -	35.45		0.00%	$ 27,339.91	$ -	$ 27,339.91	$ 27,086.00	$ 253.91	$ -		$ 27,339.91
1810	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 3,614,381.00	$ -	33.32		0.00%	$ 108,474.82	$ -	$ 108,474.82	$ 104,104.00	$ 4,370.82	$ -		$ 108,474.82
1820	Distribution Station Equipment <50 kV	$ 44,402.06	$ -	8.63		0.00%	$ 5,145.08	$ -	$ 5,145.08	$ 1,560.00	$ 3,585.08	$ -		$ 5,145.08
1825	Storage Battery Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 10,132,752.00	$ 215,000.00	28.13	39.38	2.54%	$ 360,211.59	$ 2,729.81	$ 362,941.40	$ 374,253.00	-$ 11,311.60	$ 5,459.62		$ 365,671.21
1835	Overhead Conductors & Devices	$ 8,684,530.00	$ 958,000.00	38.10	52.76	1.90%	$ 227,940.42	$ 9,078.85	$ 237,019.27	$ 243,122.00	-$ 6,102.73	$ 18,157.70		$ 246,098.12
1840	Underground Conduit	$ 8,479,323.00	$ 35,000.00	37.56	49.23	2.03%	$ 225,754.07	$ 355.47	$ 226,109.55	$ 233,392.00	-$ 7,282.45	$ 710.95		$ 226,465.02
1845	Underground Conductors & Devices	$ 14,475,705.60	$ 856,100.00	23.32	34.45	2.90%	$ 620,742.09	$ 12,425.25	$ 633,167.35	$ 640,974.00	-$ 7,806.65	$ 24,850.51		$ 645,592.60
1850	Line Transformers	$ 11,444,812.00	$ 502,000.00	26.28	39.79	2.51%	$ 435,495.13	$ 6,308.12	$ 441,803.25	$ 447,040.00	-$ 5,236.75	$ 12,616.24		$ 448,111.36
1855	Services (Overhead & Underground)	$ 1,140,823.00	$ 110,000.00	20.13	25.00	4.00%	$ 56,672.78	$ 2,200.00	$ 58,872.78	$ 56,061.00	$ 2,811.78	$ 4,400.00		$ 61,072.78
1860	Meters	$ 2,756,554.33	$ 205,000.00	7.62	20.49	4.88%	$ 361,752.54	$ 5,002.44	$ 366,754.98	$ 427,843.38	-$ 61,088.40	$ 10,004.88		$ 371,757.42
1860	Meters (Smart Meters)	$ 5,329,835.00	$ -	12.69		0.00%	$ 420,002.76	$ -	$ 420,002.76	$ 355,322.00	$ 64,680.76	$ -		$ 420,002.76
1905	Land	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 4,500.00	$ -	9.00		0.00%	$ 500.00	$ -	$ 500.00	$ 500.00	$ -	$ -		$ 500.00
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 42,739.00	$ 77,500.00	3.00	4.00	25.00%	$ 14,246.33	$ 9,687.50	$ 23,933.83	$ 18,325.73	$ 5,608.10	$ 19,375.00		$ 33,621.33
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1925	Computer Software	$ -	$ -			0.00%	$ -	$ -		$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,012,938.00	$ 200,000.00	6.63	13.00	7.69%	$ 152,781.00	$ 7,692.31	$ 160,473.30	$ 161,947.00	-$ 1,473.70	$ 15,384.62		$ 168,165.61
1935	Stores Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 91,987.00	$ 25,000.00	5.41	10.00	10.00%	$ 17,003.14	$ 1,250.00	$ 18,253.14	$ 17,781.00	$ 472.14	$ 2,500.00		$ 19,503.14
1945	Measurement & Testing Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1950	Power Operated Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls - Customer Premises	$ -	$ -			0.00%	$ -	$ -		$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 544,225.71	$ 150,000.00	16.28	20.00	5.00%	$ 33,429.10	$ 3,750.00	$ 37,179.10	$ 31,605.00	$ 5,574.10	$ 7,500.00		$ 40,929.10
1985	Miscellaneous Fixed Assets	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 3,636,217.72	-$ 203,440.00	25.68	41.50	2.41%	-$ 141,597.26	-$ 2,451.08	-$ 144,048.35	-$ 105,753.00	-$ 38,295.35	-$ 4,902.17		-$ 146,499.43
2040	Plant Held for Future Use	-$ 0.16	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
2055	Work in Progress	$ 24,009.17	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ 65,698,334.85	$ 3,440,160.00				$ 3,017,850.81	$ 89,028.67	$ 3,106,879.47	$ 3,157,530.74	-$ 50,651.26	$ 178,057.34	$ -	$ 3,195,908.14
		$ -	$ -							$ -				

Table 4.38

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ 152,663.30		$ 152,663.30
1612	Land Rights (Formally known as Account 1906)			0.00%	$ 1,294.01		$ 1,294.01
1805	Land			0.00%	$ -		$ -
1808	Buildings			0.00%	$ 27,339.91		$ 27,339.91
1810	Leasehold Improvements			0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ 108,474.82		$ 108,474.82
1820	Distribution Station Equipment <50 kV			0.00%	$ 5,145.08		$ 5,145.08
1825	Storage Battery Equipment			0.00%	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ 365,671.21		$ 365,671.21
1835	Overhead Conductors & Devices			0.00%	$ 246,098.12		$ 246,098.12
1840	Underground Conduit			0.00%	$ 226,465.02		$ 226,465.02
1845	Underground Conductors & Devices			0.00%	$ 645,592.60		$ 645,592.60
1850	Line Transformers			0.00%	$ 448,111.36		$ 448,111.36
1855	Services (Overhead & Underground)			0.00%	$ 61,072.78		$ 61,072.78
1860	Meters			0.00%	$ 371,757.42		$ 371,757.42
1860	Meters (Smart Meters)			0.00%	$ 420,002.76		$ 420,002.76
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ 500.00		$ 500.00
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ 33,621.33		$ 33,621.33
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment			0.00%	$ 168,165.61		$ 168,165.61
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ 19,503.14		$ 19,503.14
1945	Measurement & Testing Equipment			0.00%	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ 40,929.10		$ 40,929.10
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1995	Contributions & Grants			0.00%	-$ 146,499.43		-$ 146,499.43
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$ -			$ 3,195,908.14	$ -	$3,195,908.14
	Depreciation expense adjustment resulting from amortization of Account 1575				$ -		
	Total Depreciation expense to be included in the test year revenue requirement				**$ 3,195,908.14**		

4.0 Energy Probe-24

Ref: Exhibit 4, Tab 3, Schedule 2

a) Please provide a copy of BPI's federal and provincial tax returns for 2012.

Response: BPI's 2012 Federal and Provincial Tax Returns are included as Attachment K.

b) Did BPI claim any tax credits in 2012? If yes, please indicate the amounts claimed for each credit.

Response: BPI claimed $5,599 for the Ontario Co-operative Education Tax Credit (Schedule 550) in 2012.

4.0 Energy Probe-25

Ref: Exhibit 4, Tab 3, Schedule 3 &
Exhibit 2, Tab 2, Schedule 1

a) Please reconcile the 2012 additions of $5,206,471 found in Table 2.13 of Exhibit 2, Tab 2, Schedule 1 with the additions for CCA purposes of $4,195,299 shown in Table 4.48 of Exhibit 4, Tab 3, Schedule 3.

Response: This reconciliation appears at the bottom of Exhibit 4, Tab 3, Schedule 3, Page 1 of 3 (below Table 4.48)

	Total Additions
Reconciliation	
CCA Cont. Schedule (2012)	$ 4,195,299.00
FA Cont. Schedule (2012)	$ 5,206,471.00
Difference	$ (1,011,172.00)
Capitalized Overheads	$ 1,033,000.00
Smart Meters (from 1555)	-$ 86,528.00
Land Rights	$ 64,700.00
Final Difference	$ -

b) Does Table 4.48 reflect actual CCA figures for 2012? If not, please provide a revised Table 4.48 and 4.50 that reflects actual figures for 2012.

Response: Tables 4.48 and 4.50 have been updated to reflect actual CCA figures for 2012.

CCA Continuity Schedule (2013)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions
1	Distribution System - 1988 to 22-Feb-2005	31,193,346	0	0	31,193,346	0	0
2	Distribution System - pre 1988	0	0	0	0	0	0
6	Buildings - after 1990	0	0	0	0	0	0
8	General Office/Stores Equip	351,742	0	0	351,742	25,000	0
10	Computer Hardware/ Vehicles	615,448	0	0	615,448	200,000	0
10.1	Certain Automobiles	0	0	0	0	0	0
12	Computer Software	100,070	0	0	100,070	310,000	0
3	Buildings - pre 1990	0	0	0	0	0	0
		0	0	0	0	0	0
13 3	Lease # 3	0	0	0	0	0	0
13 4	Lease # 4	0	0	0	0	0	0
14	Franchise	0	0	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	0	0	0	0	0	0
50	Computers & Systems Hardware acq'd post Mar 19/07	136,671	0	0	136,671	77,500	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0
47	Distribution System - post 22-Feb-2005	28,482,074			28,482,074	2,827,661	0
	SUB-TOTAL - UCC	**60,879,349**	**0**	**0**	**60,879,349**	**3,440,161**	**0**
						484,831	0
CEC	Goodwill	0	0	0	0		
CEC	Land Rights	0	0	0	0		
CEC	FMV Bump-up	0	0	0	0		
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**		

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				626,017
<u>Additions:</u>				
Cost of Eligible Capital Property Acquired during the 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 31, 2002	0	x 1/2 =	0	
			0	626,017
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				626,017
<u>Deductions:</u>				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	626,017
Cumulative Eligible Capital Balance				626,017
CEC Deduction	7%			43,821
Cumulative Eligible Capital - Closing Balance				582,196

1

4.0 SEC-11

Ref: Exhibit 4, Tab 2, Schedule 3

Please provide any formal documents such as legal agreements between the Applicant and the City of Branford detailing the re-organization and the transfer of employees to the Applicant.

Response: BPI has attached the following documents pertaining to the reorganization and transfer of employees as Attachment L to this document:

- Template of correspondence to City of Brantford employees to be transferred who were subject to IBEW and CUPE collective agreements dated December 15, 2011;
- Template of correspondence to City of Brantford employees to be transferred who were members of the City's non-union association dated December 15, 2011;
- Template of correspondence sent to all employees who were being transferred, which set out employment terms upon transfer; and
- Memorandum of Agreement between the Canadian Union of Public Employees, Local 181 ("CUPE") and Brantford Power Inc.

BPI notes that while the date of transfer on the correspondence dated December 15, 2011 is March 1, 2012, the transfer of employees occurred on April 1, 2012.

4.0 SEC-12

Ref: Exhibit 4, Tab 2, Schedule 3, p.1-2

Please update Appendix 2-F to include a column for Test Year year-to-date actuals.

Response: Please find below Appendix 2-G, with a column added to reflect 2013 Test year-to-date actual until the end of September. Please note that the question referred to Appendix 2-F, however the reference pertained to Appendix 2-G.

Account	Descriptio	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year	2013 YTD SEPTEMBER
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations									
5005	Operation	$ 244,352	$ 332,926	$ 335,123	$ 327,414	$ 226,223	$ 387,915	$ 273,250	$ 522,432
5010	Load Disp	$ 16,375	$ 35,700	$ 49,739	$ 31,918	$ 45,927	$ 43,685	$ 114,745	$ 29,963
5012	Station Bu	$ 36,464	$ 33,982	$ 29,812	$ 25,755	$ 29,252	$ 25,449	$ 29,322	$ 26,120
5014	Transform	$ 6,205	$ 5,596	$ 7,009	$ 15,354	$ 7,906	$ 6,611	$ 24,787	$ 18,271
5015	Transform	$ 51,220	$ 67,308	$ 72,587	$ 96,171	$ 75,365	$ 79,709	$ 102,609	$ 46,323
5016	Distributic	$ 1,959	$ 2,387	$ 1,277	$ 4,208	$ 1,743	$ 1,260	$ 1,962	$ -
5017	Distributic	$ 3,612	$ 1,512	$ 1,134	$ 1,155	$ 400	$ 357	$ 520	$ 37
5020	Overhead	$ 3,019	$ 2,523	$ 1,771	$ 1,928	$ 985	$ -	$ 1,962	$ 308
5025	Overhead	$ 13,806	$ 6,293	$ 6,026	$ 1,976	$ 10,893	$ 11,333	$ 12,752	$ 2,177
5030	Overhead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5035	Overhead	$ 14,800	$ 8,986	$ 9,393	$ 3,868	$ 2,989	$ 907	$ 5,154	
5040	Undergrou	$ 1,043	$ 139	$ 1,671	$ 1,178	$ 670	$ 27	$ -	$ 876
5045	Undergrou	$ 18,921	$ 5,625	$ 10,635	$ 6,267	$ 9,508	$ 10,661	$ 11,990	$ 307
5050	Undergrou	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5055	Undergrou	$ 3,290	$ 1,387	$ 1,736	$ 685	$ 665	$ 52	$ -	
5060	Street Ligh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5065	Meter Exp	$ 452,578	$ 285,758	$ 265,762	$ 363,773	$ 464,155	$ 548,618	$ 593,094	$ 266,721
5070	Customer	$ 5,979	$ 315	$ 334	$ 461	$ 710	$ 430	$ 5,292	$ 881
5075	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 190,106
5085	Miscellan	$ 118,312	$ 253,078	$ 186,167	$ 182,823	$ 221,832	$ 182,710	$ 329,209	$ -
5090	Undergrou	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5095	Overhead	$ 6,285	$ 13,596	$ 19,983	$ 6,869	$ 7,343	$ 6,711	$ 25,403	$ 5,034
5096	Other Ren	$ -	$ -	$ 8,233	$ 4,540	$ 4,732	$ 15,862	$ 44,455	$ 8,258
Total - Operations		$998,220	$1,057,112	$1,008,391	$1,076,343	$1,111,298	$1,322,296	$1,576,506	$ 1,117,814

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year	2013 YTD SEPTEMBER
Maintenance									
5105	Maintenance Supervision and Engineering	$ 280,966	$ 304,849	$ 325,801	$ 307,486	$ 432,478	$ 204,823	$ 499,599	$ 198,452
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 3,970	$ 431	$ 1,031	$ 1,892	$ 1,559	$ 930	$ 2,158	$ 2,354
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 2
5114	Maintenance of Distribution Station Equipment	$ 16,206	$ 9,409	$ 10,704	$ 5,684	$ 6,747	$ 1,203	$ 9,805	$ 23,684
5120	Maintenance of Poles, Towers and Fixtures	$ 153,188	$ 135,624	$ 57,113	$ 44,139	$ 32,442	$ 59,222	$ 75,414	$ 142,381
5125	Maintenance of Overhead Conductors and Devices	$ 194,468	$ 128,912	$ 109,023	$ 196,827	$ 184,573	$ 157,869	$ 242,022	$ 197,791
5130	Maintenance of Overhead Services	$ 201,225	$ 200,498	$ 229,757	$ 218,602	$ 192,135	$ 162,683	$ 247,604	$ 297,175
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 333,592	$ 399,183	$ 396,203	$ 348,542	$ 415,898	$ 391,195	$ 499,535	$ 52,378
5145	Maintenance of Underground Conduit	$ 66,733	$ 75,395	$ 38,898	$ 54,614	$ 52,661	$ 55,273	$ 56,902	$ 145,580
5150	Maintenance of Underground Conductors and Devices	$ 111,669	$ 138,560	$ 89,626	$ 71,835	$ 70,158	$ 49,277	$ 82,311	$ 149,778
5155	Maintenance of Underground Services	$ 204,053	$ 221,815	$ 143,095	$ 138,372	$ 109,059	$ 109,014	$ 124,877	$ 200,311
5160	Maintenance of Line Transformers	$ 159,264	$ 108,654	$ 279,921	$ 68,591	$ 305,006	$ 236,456	$ 192,863	$ 410
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5175	Maintenance of Meters	$ -	$ 26	$ -	$ -	$ 153	$ 141	$ -	
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total - Maintenance		$ 1,725,334	$1,723,356	$1,681,173	$1,456,583	$1,802,869	$1,428,085	$2,033,090	$ 1,410,291

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year	2013 YTD SEPTEMBER
Billing and Collecting									
5305	Supervision	$ 135,049	$ 175,292	$ 181,121	$ 161,326	$ 223,136	$ 258,214	$ 292,372	$ 251,639
5310	Meter Reading Expense	$ 371,227	$ 440,325	$ 402,412	$ 354,422	$ 274,993	$ 408,268	$ 240,556	$ 378,444
5315	Customer Billing	$ 466,741	$ 542,936	$ 555,894	$ 495,101	$ 542,425	$ 586,654	$ 964,616	$ 582,014
5320	Collecting	$ 300,111	$ 350,585	$ 362,242	$ 322,653	$ 359,916	$ 305,480	$ 536,496	$ 216,826
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 2
5330	Collection Charges	$ 2,251	$ 548	$ 454	$ 833	$ 1,000	$ 12,413	$ 500	$ -
5335	Bad Debt Expense	$ 183,090	$ 257,772	$ 211,527	$ 307,532	$ 300,000	$ 163,887	$ 306,000	$ 213,161
5340	Miscellaneous Customer Accounts Expenses	$ 649,367	$ 438,231	$ 452,803	$ 403,316	$ 506,862	$ 560,922	$ 522,675	$ 333,331
Total - Billing and Collecting		$ 2,107,836	$2,205,690	$2,166,453	$2,045,182	$2,208,332	$2,295,837	$2,863,215	$ 1,975,413

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year	2013 YTD SEPTEMBER
Community Relations									
5405	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5410	Community Relations - Sundry	$ 114,588	$ 119,559	$ 113,351	$ 106,211	$ 156,330	$ 148,571	$ 152,526	$ 26,467
5415	Energy Conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5420	Community Safety Program	$ 12,743	$ 8,270	$ 18,029	$ 9,412	$ 12,807	$ 12,068	$ 19,051	$ 11,000
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,200	
5505	Supervision	$ -	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ 127,331	$ 127,829	$ 131,379	$ 115,623	$ 169,137	$ 160,639	$ 232,777	$ 37,467

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year	2013 YTD SEPTEMBER
Administrative and General Expenses									
5605	Executive Salaries and Expenses	$ 392,793	$ 388,053	$ 403,908	$ 319,673	$ 533,369	$ 540,492	$ 729,401	$ 669,431
5610	Management Salaries and Expenses	$ 662,071	$ 397,061	$ 402,930	$ 302,363	$ 340,676	$ 253,135	$ 384,158	$ 208,818
5615	General Administrative Salaries and Expenses	$ 664,697	$ 867,658	$ 917,874	$ 884,744	$ 875,651	$ 949,117	$ 582,990	$ 444,801
5620	Office Supplies and Expenses	$ 48,202	$ 65,075	$ 57,260	$ 51,082	$ 58,468	$ 61,555	$ 80,250	$ 52,384
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5630	Outside Services Employed	$ 164,324	$ 39,291	$ 58,600	$ 127,715	$ 138,735	$ 100,792	$ 220,000	$ 64,170
5635	Property Insurance	$ -	$ 99,320	$ 74,245	$ 99,678	$ 100,861	$ 100,723	$ 133,133	$ 79,847
5640	Injuries and Damages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5645	OMERS Pensions and Benefits	$ 101,036	$ 244,532	$ 215,393	$ 175,099	$ 302,000	$ 433,800	$ 108,000	$ 84,070
5646	Employee Pensions and OPEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5647	Employee Sick Leave	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5650	Franchise Requirements	$ 49,316	$ 50,606	$ 53,427	$ 53,775	$ 57,569	$ 57,569	$ 59,000	$ 44,076
5655	Regulatory Expenses	$ 196,822	$ 284,560	$ 184,346	$ 120,735	$ 135,500	$ 125,787	$ 144,500	$ 187,576
5660	General Advertising Expenses	$ 23,802	$ 20,789	$ 27,398	$ 15,894	$ 13,600	$ 29,123	$ 40,000	$ 25,306
5665	Miscellaneous General Expenses	$ 171,754	$ 119,196	$ 84,705	$ 151,291	$ 8,341	$ 168,325	-$ 1,995	$ 109,998
5670	Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5672	Lease Payment Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5675	Maintenance of General Plant	$ 54,927	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5680	Electrical Safety Authority Fees	$ 18,309	$ 16,129	$ 16,167	$ 16,013	$ 16,400	$ 16,305	$ 19,000	$ 16,250
5681	Special Purpose Charge Expense	$ -	$ -	$ 376,534	$ -	$ -	$ -	$ -	
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ 51,566	$ 51,566	$ 51,758	$ 60,000	$ 56,177	$ -	$ 51,742
5695	OM&A Contra Account	$ -	-$ 29,756	$ 46,971	-$ 51,215	-$ 120,132	-$ 193,257	$ -	
6205	Donations	$ -				$ -	$ -		
6205	Donations, Sub-account LEAP Funding	$ -	$ -	$ -	$ -		$ -		
Total - Administrative and General Expenses		$ 2,548,053	$ 2,614,082	$ 2,971,323	$ 2,318,604	$ 2,521,038	$ 2,699,643	$ 2,498,437	$ 2,038,468
Total OM&A		$ 7,506,774	$ 7,728,069	$ 7,958,720	$ 7,012,336	$ 7,812,674	$ 7,906,500	$ 9,204,025	$ 6,579,453
Adjustments for non-recoverable items									
5681	Special Purpose Charge Expense			$ 376,534					
6205	Donations[1]								
Total Recoverable OM&A		$ 7,506,774	$ 7,728,069	$ 7,582,186	$ 7,012,336	$ 7,812,674	$ 7,906,500	$ 9,204,025	$ 6,579,453

Account	Description	Last Rebasing Year 2008	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year	2013 YTD SEPTEMBER
Administrative and General Expenses									
5605	Executive Salaries and Expenses	$ 392,793	$ 388,053	$ 403,908	$ 319,673	$ 533,369	$ 540,492	$ 729,401	$ 669,431
5610	Management Salaries and Expenses	$ 662,071	$ 397,061	$ 402,930	$ 302,363	$ 340,676	$ 253,135	$ 384,158	$ 208,818
5615	General Administrative Salaries and Expenses	$ 664,697	$ 867,658	$ 917,874	$ 884,744	$ 875,651	$ 949,117	$ 582,990	$ 444,801
5620	Office Supplies and Expenses	$ 48,202	$ 65,075	$ 57,260	$ 51,082	$ 58,468	$ 61,555	$ 80,250	$ 52,384
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5630	Outside Services Employed	$ 164,324	$ 39,291	$ 58,600	$ 127,715	$ 138,735	$ 100,792	$ 220,000	$ 64,170
5635	Property Insurance	$ -	$ 99,320	$ 74,245	$ 99,678	$ 100,861	$ 100,723	$ 133,133	$ 79,847
5640	Injuries and Damages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5645	OMERS Pensions and Benefits	$ 101,036	$ 244,532	$ 215,393	$ 175,099	$ 302,000	$ 433,800	$ 108,000	$ 84,070
5646	Employee Pensions and OPEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5647	Employee Sick Leave	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5650	Franchise Requirements	$ 49,316	$ 50,606	$ 53,427	$ 53,775	$ 57,569	$ 57,569	$ 59,000	$ 44,076
5655	Regulatory Expenses	$ 196,822	$ 284,560	$ 184,346	$ 120,735	$ 135,500	$ 125,787	$ 144,500	$ 187,576
5660	General Advertising Expenses	$ 23,802	$ 20,789	$ 27,398	$ 15,894	$ 13,600	$ 29,123	$ 40,000	$ 25,306
5665	Miscellaneous General Expenses	$ 171,754	$ 119,196	$ 84,705	$ 151,291	$ 8,341	$ 168,325	-$ 1,995	$ 109,998
5670	Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5672	Lease Payment Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5675	Maintenance of General Plant	$ 54,927	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5680	Electrical Safety Authority Fees	$ 18,309	$ 16,129	$ 16,167	$ 16,013	$ 16,400	$ 16,305	$ 19,000	$ 16,250
5681	Special Purpose Charge Expense	$ -	$ -	$ 376,534	$ -	$ -	$ -	$ -	
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ 51,566	$ 51,566	$ 51,758	$ 60,000	$ 56,177	$ -	$ 51,742
5695	OM&A Contra Account	$ -	-$ 29,756	$ 46,971	-$ 51,215	-$ 120,132	-$ 193,257	$ -	
6205	Donations	$ -				$ -	$ -		
6205	Donations, Sub-account LEAP Funding	$ -	$ -	$ -	$ -		$ -		
Total - Administrative and General Expenses		$ 2,548,053	$2,614,082	$2,971,323	$2,318,604	$2,521,038	$2,699,643	$2,498,437	$ 2,038,468
Total OM&A		$ 7,506,774	$7,728,069	$7,958,720	$7,012,336	$7,812,674	$7,906,500	$9,204,025	$ 6,579,453
Adjustments for non-recoverable items									
5681	Special Purpose Charge Expense			$ 376,534					
6205	Donations[1]								
Total Recoverable OM&A		$ 7,506,774	$7,728,069	$7,582,186	$7,012,336	$7,812,674	$7,906,500	$9,204,025	$ 6,579,453

4.0 SEC-13

Ref: Exhibit 4, Tab 2, Schedule 3

What date was the Test Year OM&A budget included in this application finalized.

Response: The Test Year OM&A budget included in this application was finalized on January 17, 2013 and was approved by the BPI Board of Directors.

4.0 SEC-14

Ref: Exhibit 4, Tab 2, Schedule 5, p.4

How did the Applicant determine the reasonableness of the cost of services it purchased from the City prior to the implementation of the renegotiated SSA?

Response: In accordance with *Clause 3 – Annual Review of Services* of the agreement between the Corporation of the City of Brantford and Brantford Power Inc. dated October 24, 2000, which was the agreement in place prior to implementation of the renegotiated SSA, BPI and the City undertook a review of the services purchased from the City annually as part of the budget process.

Clause 3 – Annual Review of Schedules of the previous agreement stated:

(a) The parties shall review the contents of each schedule on an annual basis. The purpose of such review shall be to determine whether the activities described in each Schedule continue to be accurate. In the event that during such review, disagreements arise with respect to suggested amendments to any Schedule and these disagreements cannot be settled by the parties, any party shall have the ability to require the contents of the Schedule or Schedules under disagreement to be submitted to arbitration in accordance with section 5 of the agreement.

(b) The review described in (a) above shall be commenced within sufficient time so that the parties might reasonably have completed their review in time for the annual City budget and estimates process.

4.0 SEC-15

Ref: Exhibit 4, Tab 2, Schedule 5, p.1

Please provide a copy of the current collective agreement with CUPE and the last collective agreement with the IBEW.

Response: Please find the current CUPE Collective Agreement as well as the the last and current IBEW Collective Agreements as Attachment M.

4.0 SEC-16

Ref: Exhibit 4, Tab 2, Schedule 5, p.1

Please provide an update on negotiations on a new collective agreement with the IBEW.

Response: BPI has finished negotiations with IBEW. A copy of its new collective agreement has been provided in response to 4.0-SEC-15.

4.0 SEC-17

Ref: Exhibit 4, Tab 2, Schedule 6, p.8-9

With regards to Forestry (Tree Trimming):

a) What was the cost of Tree Trimming in 2012?

Response: The cost of tree trimming services in 2012 was $400,651.16.

b) Has the scope of Tree Trimming services changed since 2012? If so, please detail.

Response: BPI's standard for proactive tree trimming is to trim all trees in its distribution service territory over a three-year period. In recent years, there has been a decline in this three year cycle such that trees were being trimmed over a five-year period. In 2013, there has been an increase in proactive tree trimming activity to return to the three-year standard. As well, there has been an increase in reactive tree trimming activity to address particular areas of concern caused, in part, in the decline in the three-year tree trimming cycle.

3.0 VECC-19

Reference: Exhibit 4, Tab 2, Schedule 1, pg. 4 / Schedule 3, Tables 4-13 to 4-17

a) The evidence states that the 2012 bridge year is a forecast. If this is correct please provide the year end actual 2012 OM&A spending in detailed format (i.e. Appendix 2-G).

Response: Please refer to 4-Energy Probe-21.

4.0 VECC- 20

Reference: Exhibit 4, Tab 2, Schedule 1, pg. 4 / Schedule 3, Tables 4-13 to 4-17

a) Please provide a similar update for 2013, but showing 2013 actual spending to-date (ending 3rd quarter) and the forecast remaining budget.

Response: Please refer to 4-SEC-12

4.0 - VECC- 21

Reference: Exhibit 4, Tab 2, Schedule 4

a) Please provide a breakdown of the meter reading expense in 2013 as compared to 2008. Also provide the number of meters read in 2008 and the projected number of meters to be read in 2013. If the frequency of meter reads has changed during the period please explain the impact on costs.

Response: Please find a table below which outlines the costs and meters read in 2008 and 2013. Please note, the cost of notice of delivery for 2013 is actually included in the $40,000 for meter reading costs.

4.0-VECC-21		
	2008	**2013**
Meter Reading Costs	$ 102,319	$ 40,000
Check Readings/Notice of Delivery	$ 16,298	$ -
Maintenance, Meter Reading Equipment	$ 2,221	$ -
# Active Electric Meters	36,769	290
# Interval Meters	96	215
# Active Smart Meters	0	38,194
Smart Meter Reading and Billing Expense	$ -	$ 139,440
Meter Reading Expense	$ -	$ 78,573
Interval Customer Billing	$ 29,810	$ 62,011
Total	$ 150,648	$ 320,024

Meter reading frequency has not changed from 2008 to 2013; meters are still read on a monthly basis. The only exception is where a customer location has changed from a conventional meter to a smart meter because the conventional meter read monthly walk or drive changed to a daily over the air meter read.

4.0 VECC- 22

Reference: Exhibit 4, Tab 2, Schedule 1, pg. 3

a) Please provide the calculation which shows the derivation of the proposed $20,900 in LEAP funding for 2013. Specifically, did BPI use the Service Revenue Requirement before or after Revenue offsets for the purpose of this calculation?

Response: BPI advises that the derivation of the proposed $20,900 in LEAP funding was based on the Service Revenue Requirement after revenue offsets. Using the Service Revenue Requirements before revenue offsets, the amount of LEAP funding is $21,547**.** As set out at Exhibit 4-Tab2-Schedule 1 page 3 of 4 of BPI's application, the amount of LEAP funding may need to be adjusted once the service revenue requirement is finalized in this proceeding. BPI will make all adjustments at that time.

4.0 VECC- 23

Reference: Exhibit 4, Tab 1

a) Please provide the association fees paid to the EDA for each of the years 2008 through 2013.

Response: Please find below a table outlining BPI's annual EDA fees:

EDA FEES	
2008	$ 47,500
2009	$ 48,500
2010	$ 50,500
2011	$ 52,100
2012	$ 55,000
2013	$ 57,000

b) Separately provide and describe the cost of all other association memberships.

Response: Please find below other corporate memberships that BPI pays for.

	2008	2009	2010	2011	2012	2013
Ontario Energy Board Annual Registration Fee	$ 1,333	$ 800	$ 932	$ -	$ -	$ -
Brantford Regional Chamber of Commerce	$ 497	$ 506	$ 515	$ -	$ 544	$ 700
Brantford Home Builders Association	$ -	$ -	$ 680	$ 680	$ 725	$ 1,300
Service Clubs (MEARIE)	$ 800	$ 800	$ 800	$ 995	$ 1,300	$ -
OEB Assessment	$ 96,555	$ 105,597	$ 106,197	$ 104,180	$ 108,000	$ 108,000
Total	$ 101,193	$ 109,712	$ 111,134	$ 107,866	$ 112,581	$ 112,013

4.0 VECC- 24

Reference: Exhibit 4, Tab 2, Schedule 3, pg.1

a) Please confirm that the 2013 is the first year BPI applied its new capitalization policy.

Response: BPI confirms that 2013 is the first year that BPI applied the new capitalization policy.

4.0 VECC- 25

Reference: Exhibit 4, Tab 2, Schedule 4

a) Please provide and detail all one-time costs incurred in 2012 related to the restructuring (e.g. severances, studies, moving costs, etc.)

Response: One-time costs included the preparation of two actuarial reports at a cost of $11,000 (please refer to Exhibit 4, Tab 2, Schedule 5, page 22 for further details), legal services at a cost of $57,195 and the preparation of a transition plan which amounted to $12,260. The total of one-time costs in 2012 was $80,455.

b) Please provide all one-time costs budgeted in 2013 related to corporate restructuring.

Response: There were no one-time costs budgeted in 2013 related to corporate restructuring.

4.0 VECC- 26

Reference: Exhibit 4, Tab 4, Schedule 1, pg. 10 / Attachment 2

a) Please provide the 2013 incremental ongoing costs as compared to 2008 for:

(1) Smart meter reading and billing (show any reductions due to meter reading changes separately)

	2008	2013
Meter Reading Costs	$ 102,319	$ 40,000
Check Readings/Notice of Delivery	$ 16,298	$ -
Maintenance, Meter Reading Equipment	$ 2,221	$ -
# Active Electric Meters	36,769	290
# Interval Meters	96	215
# Active Smart Meters	0	38,194
Smart Meter Reading and Billing Expense	$ -	$ 139,440
Meter Reading Expense	$ -	$ 78,573
Interval Customer Billing	$ 29,810	$ 62,011
Total	$ 150,648	$ 320,024

The incremental ongoing cost between 2013 and 2008 is $169,376. In addition to this, another incremental cost is the cost of 1 full-time equivalent employee at a cost of $90,200 (not included in the $169,376 for meter reading and billing expenses). The total incremental ongoing cost is $259,576.

Also, the projected $40,000 meter reading costs for 2013 include the notice delivery costs.

(2) Smart meter maintenance as compared to prior generation of meters.

Response: BPI does not perform meter maintenance. BPI believes that there are no maintainable parts to the meter that are available to staff without the removal of the Measurement Canada seal. Once a Measurement Canada seal is broken, the meter must be verified for accuracy at a Measurement Canada accredited meter verifier. BPI does not hold such a designation with Measurement Canada. Used, BPI owned meters which have been verified by an accredited meter verifier are returned to active meter inventory for reuse. Costs for this work are charged to 5065 as per the Accounting Procedures Handbook for Electricity Distributors.

(3) Ongoing cost due corporate restructuring. Please show the both the pre and post restructuring cost. For example, for customer service please show the 2012 (or last pre-restructuring year cost) as compared to the same functions after restructuring.

Response: Some of the post-restructuring on-going costs realized by BPI include Customer Service cost increases due to compensation and staffing in the amount of $199,185 and Supplies and Contracted Services in the amount of $289,405, costs from the re-allocation of 100% of corporate officers of $72,469. Further details of these costs can be found in Exhibit 4, Tab 2, Schedule 4, page 4 and Exhibit 4, Tab 2, Schedule 3, pages 20-23. There is also an increase in the Finance department of one full-time equivalent employee. As discussed in Exhibit 4, Tab 2, Schedule 3, page 26, this results in an increase in the amount of $77,000.

4.0 VECC – 27

Reference: Exhibit 4, Tab 2, Schedule 3 / Schedule 4, pg.12

Preamble: *BPI shows a very large change in OM&A due to changes to its capitalization policy. The amount shown in Table 4.18 is a total of $972,502.*

a) Please explain if (or how) the corporate restructuring which substitutes some contracting services with direct employment impacts the capitalization costs. For example, would the dollar impact of the capitalization policy change been significantly different under the previous corporate structure? If so, would the difference have been material?

Response: The capitalized costs did not change as a result of the transfer of employees to BPI. There was no change in accounting treatment as staff track their time and are paid the same.

4.0 VECC- 28

Reference: Exhibit 4, Tab 2, Schedule 3, pg.1

a) Please explain what activities are accounted for under account 5410 – Community Relations – Sundry. Please also explain what has caused these costs to have increased by over 30% since 2008.

Response: The activities in this account include locate services and restoration services, in addition to labour and truck time as a result of providing these services.

The main reason for the 30% increase between 2008 and 2013 in account 5410, Community Relations – Sundry, is that $20,910 for LEAP funding was placed in this account, in addition to $27,993 was allocated for indirect costs which were a result of the change in BPI's capitalization policy.

4.0 VECC – 29

Reference: Exhibit 4, Tab 2, Schedule 3, pg.6

a) Does BPI currently do billing in-house or is this service contracted out with the City (or some other party)? If the service is contracted out please explain how customer services, which BPI has indicated were brought in- house in 2013 (E4/T2/S3/pg.3) are integrated with the billing system.

Response: Since Customer Services has been transferring to BPI, billing is now completed in-house and is not contracted out with the City or any other party.

4.0 VECC – 30

Reference: Exhibit 4, Tab 2, Schedule 5, Appendix 2-k

a) Please revise Appendix 2-K to show only the actual FTEs employed by BPI in 2008 through to 2013 (or confirm that is what the current table shows).

Response: Please refer to the updated Appendix 2-K provided in response to 4-Staff-20.

4.0 VECC – 31

Reference: Exhibit 4, Tab 2, Schedule 6, pg.7

a) Please list the IT systems that were supported by the City Affiliate in 2008 and compare that to the services provided in 2013. If workstation support is included please provide the number of workstations supported in 2008 and 2013.

Response: The table below identifies the IT systems used by BPI and supported by the City affiliate in 2008 as compared to 2013:

SYSTEMS SUPPORTED	2008	2013
Cleo (AS2)		X
Daffron Customer Information System	X	X
JDE Financial Information System	X	X
SPI Group - Hub Connector		X
IBM Content Manager - On Demand		X
Profound Logic Software - RPG Alive		X
Help Systems - Abstract	X	X
Help Systems - Robot Scheduler	X	X
Settlement 1, Kinetiq	X	X
Itron - MV-90	X	X
Paging Software	X	X
Cannon - Yukon Control	X	X
Website domains	X	X
Canada Post	X	X
Prism Data Services		X
AS/400 Upgrades	X	
AS/400 Back-up and Recovery	X	X
Versatile Records Management System	X	X
Microsoft Office software	X	X
Firewalls	X	X
Systrends	X	

Miscellaneous systems – PC Pro, e-demand, Prism	X	

The City affiliate supported an estimated number of 46 workstations in 2008 as compared with 50 workstations in 2013.

b) Does BPI employ any IT professionals directly? If yes, please describe their activity and cost.

Response: BPI does not employ any IT professionals directly.

4.0 VECC – 32

Reference: Exhibit 4, Tab 2, Schedule 6, pg.7-9

a) Please list the facilities that were provided by the City Affiliate in 2008 (747k) and in 2013 (538k).

Response: The City affiliate provided the following facilities in 2008:

- Space at 100 Wellington Square for administrative services;
- Space at 84 Market Street for administrative services;
- Space at 220 Colborne Street for customer services, financial services and general administrative services;
- Space at 400 Grand River Avenue for operations services, inventory management services and warehousing and vehicle storage.

In 2013, the City affiliate provides the following facilities:

- Space at 84 Market Street for administrative and finance services;
- Space at 220 Colborne for customer services; and
- Space at 400 Grand River Avenue for operations services, inventory management services and warehousing and vehicle storage.

4.0 VECC – 33

Reference: Exhibit 4, Tab 2, Schedule 6, pg.7-9

a) Please list all in the insurance policies covering BPI liabilities.

Response: BPI insurance policies include general comprehensive liability and Directors and Officers liability through MEARIE and property insurance through the Frank Cowan Company.

b) Is BPI covered by any policy issued by the MEARIE group? If yes please provide the cost of the policy and describe its coverage.

Response: BPI is covered by the general comprehensive liability and Director's and Officer's Liability policies issued by the MEARIE group. BPI's cost in 2012 for this policy was $62,219.91

With a limit of $24,000,000 per occurrence, the MEARIE policy coverage includes:

- General liability including premises and operations and products and completed operations;
- Bodily injury liability;
- Personal injury liability;
- Property damage liability;
- Tenant's legal liability;
- Environmental impairment;
- Errors and Omissions/Professional liability;
- Non-owned automobile;
- Legal expense reimbursement regarding Conflict of Interest and Occupational Health and Safety; and
- Enhanced Directors and Officers liability.

4.0 VECC – 34

Reference: Exhibit 4, Tab 2, Schedule 6, pg.7-9

a) Please describe of list of the activities provided by the Treasury, Purchasing department of the City Affiliate in 2008 and compare that to the same category of services provided (or to be provided) in 2013.

Response: In 2008, the City Affiliate provided the following Treasury and Purchasing activities:

- Accounts Payable Processing;
- Payroll functions;
- Miscellaneous Accounts Receivables Administration;
- Financial Statements Preparation;
- Other Financial Services specific to BPI including rate applications, budgets, reports to the regulator;
- Treasury services including financial systems integrity, internal controls, investment and baking administration and policy, cheques and disbursement of funds, financial management and analysis, payroll and accounting administrative functions, purchasing services and policy, collection administrative services;
- Purchasing activities and supervision of those activities specific to BPI commonly referred to as inventory management or “Stores”.

Although not part of the Treasury, Purchasing Department in 2008, the City affiliate also provided a Chief Financial Officer who was part of the then Brantford Power Department.

In 2013, the City Affiliate provides the following services:

- Accounts Payable Processing;
- Payroll functions, and
- Purchasing or acquisition of goods and services excluding inventory management or “Stores” activities that were transferred to BPI on April 1, 2012. Supervision of those activities was assumed by the BPI Operations management.

The table below compares those activities provided by the Treasury and Purchasing Department in 2008 to the services provided in 2012.

ACTIVITY	**2008**	**2013**
Accounts Payable Processing	X	X
Payroll functions	X	X
Miscellaneous Accounts Receivables	X	
Financial Statements Preparation	X	
BPI-Specific Financial services	X	
Treasury Services	X	
Purchasing Services	X	X
Inventory Management Services	X	
Provisions of a Chief Financial Officer	X	

4.0 VECC – 35

Reference: Exhibit 4, Tab 2, Schedule 6, pg.7-9

a) When was the last time BPI tendered for forestry management? Please explain how BPI ascertains that the forestry service it receives from the City Affiliate is competitive with other providers of this service?

Response: BPI purchases forestry management or tree trimming services from its City affiliate under the shared services agreement. The service comprises two components: tree trimming services, which is contracted to a third party as a result of a valid tendering process undertaken by the City affiliate and management of the services charged to BPI on an actual cost basis. The City affiliate tendered for forestry management services in 2012.

That the tree trimming component of the service is contracted to a third party through a valid tendering process ensures that the cost of the service is competitive with other providers of this service.

b) Does the City Affiliate provide this service through its own employees or is the service contracted to a third party? If the latter, please explain why BPI does no contract with the party directly.

Response: As discussed above, actual tree trimming activities are contracted to a third party. Management of the service including responding to customer inquiries, is provided through the City affiliate.

The practice of partnering with the City of Brantford for forestry management services is a longstanding practice of the Public Utilities Commission of Brantford, the predecessor to BPI, dating back to the late 1970's. Trimming trees for both electrical distribution and municipal purposes at the same time was seen as an efficiency improvement; that is, one crew would trim a tree for both purposes rather than two crews to trim for the different purposes. The combined service also improved job planning and provided the public with a single point of contact for inquiries about tree trimming services, which was seen as an improvement in customer service.

Exhibit 5 – Cost of Capital

5.0 Staff-29

Ref: Exhibit 5, Tab 1, Schedule 1 &
Exhibit 5, Tab 1, Schedule 2, Appendix A – Affiliated Debt

Under Affiliated Debt under Exhibit 5/Tab 1/Schedule 1, BPI states:

> BPI holds a Promissory Note with City of Brantford for $24,189,168 signed January 27, 2011, at an annual rate of 5.87%, renewable every 5 years. Per the Report of the Board on Cost of Capital (EB-2009-0084), released December 11 2009, BPI submits that this note is non-callable affiliated debt, attracting historic deemed debt rates rather than the Board's current debt rate.

The *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, allows for the Board's deemed long term debt to act as a ceiling on the allowed rate for affiliated debt at the time of issuance.[1]

On November 15, 2010, the Board issued updated Cost of Capital parameters for rates effective January 1, 2011. The letter is accessible at http://www.ontarioenergyboard.ca/OEB/_Documents/2011EDR/Ltr_Jan1st_Cost_of_Capital_Parameters_20101115.pdf . The deemed Long-term debt rate as of January 1, 2011 is 5.48%.

a) Please explain why BPI believes that the affiliated debt, signed on January 27, 2011 should attract the 5.87% rate rather than the 5.48% deemed long-term debt rate as issued by the Board effective January 1, 2011.

Response: The interest rate on the promissory note of 5.87% was discussed between City of Brantford officials and BPI representatives during the preparation of annual City and BPI budgets prior to the Board's letter of November 15, 2010 setting out the updated cost of capital parameters. The note was executed in January 2011 based on the 5.87% rate embedded in the annual budgets.

5.0 Energy Probe-26

Ref: Exhibit 5, Tab 1, Schedule 1

The evidence indicates that the Promissory Note with the City of Brantford signed on January 27, 2011 is at a rate of 5.87%.

a) Please confirm that the 5.87% rate was based on the Ontario Energy Board's Cost of Capital Parameter Updates for 2010 Cost of Service Applications letter dated February 24, 2010. If this cannot be confirmed, please indicate how the 5.87% figure was arrived at.

Response: BPI confirms that the 5.87 per cent was based on the Ontario Energy Board's Cost of Capital Parameter Updates for 2010 Cost of Service Applications letter dated February 24, 2010.

b) Please provide the deemed long term debt rate, as determined by the Ontario Energy Board, at the time the promissory note was signed.

Response: The deemed long term debt rate, as determined by the Ontario Energy Board, at the time the promissory note was signed was 5.48 per cent.

c) Please provide the deemed long term debt rate, as determined by the Ontario Energy Board, based on January, 2011 data.

Response: The deemed long-term debt rate as determined by the Ontario Energy Board based on January 2011 data was 5.32 per cent as set out in correspondence from the Board dated March 3, 2011.

In that correspondence, the Board stated:

On November 15, 2010, the Board issued a letter announcing updated Cost of Capital parameters for rates effective January 1, 2011. Also in that letter the Board stated that cost of service applications with rates effective May 1, 2011 would have updated Cost of Capital parameters based on data for January 2011.

d) Did BPI attempt to replace the affiliated debt with third party debt rather renew the existing agreement for a further 5 years? If not, why not? If yes, please provide details of the third parties contacted, the rates and terms being discussed. Please provide all correspondence related to these negotiations and discussions.

Response: BPI did not attempt to replace the affiliated debt with third party debt. The Promissory Note does not provide for the ability to replace the note with third party debt.

e) Please provide a copy of the Promissory Note with the City of Brantford that had a start date of February 1, 2006 (Table 5.1) at an interest rate of 6.25%. Please also confirm that this is the promissory note that was renewed on January 27, 2011.

Response: A copy of the Promissory Note with the City of Brantford that had a start date of February 1, 2006 at an interest rate of 6.25% is attached in Attachment N. BPI confirms that this is the Promissory Note that was extended on February 1, 2011.

5.0 Energy Probe-27

Ref: Exhibit 5, Tab 1, Schedule 2,

a) Does BPI have the ability to pay down any of the outstanding principle on the affiliate promissory note?

Response: The Promissory Note does not provide BPI the ability to pay down the outstanding principal on the note.

b) If the response to (a) is yes, has BPI investigated replacing any or all of the promissory note with third party debt at a lower rate? If not, why not?

Response: Please refer to the response to 5-Energy Probe-27a.

c) Is there any penalty payable by BPI for paying down the principle during the term of the loan?

Response: Please refer to the response to 5-Energy Probe-27a.

5.0 Energy Probe-28

Ref: Exhibit 5, Tab 1, Schedule 2 &
Exhibit 6, Tab 1, Schedule 1 & RRWF

a) Please reconcile the following deemed interest expenses for the 2013 test year: $2,347,802 as shown in Table 5.8 in Exhibit 5, Tab 1, Schedule 2; $2,346,500 as shown in Table 6.2 in Exhibit 6, Tab 1, Schedule 1; and $2,345,126 as shown in the RRWF.

Response: Table 5.8 in Exhibit 5 has the incorrect rate base amount. It should be $78,748,369 instead of $78,792,090. This would then calculate a deemed interest expense of $2,346,500. The difference between this number which was also calculated in Table 6.2 in Exhibit 6 and the third calculation for deemed interest expense as found in the RRWF is due to rounding. The RRWF has been adjusted to reflect the Long term debt rate (not rounded to 2 decimal places). The two exhibits and the RRWF should now reflect the deemed interest expense of $2,346,500.

b) Please indicate which of the above figures is the correct figure to use in the calculation of the revenue requirement.

Response: The deemed interest expense in the amount of $2,346,500 is the correct figure to use in the calculation of the revenue requirement.

5.0 SEC-18

Exhibit 5, Tab 1, Schedule 1, p.2

Please provide a copy of all outstanding debt instruments not already provided in evidence.

Response: BPI provides the requested outstanding OILC debt instruments as Attachment O. The current promissory note was already provided in the evidence at Exhibit 5, Tab 1, Schedule 2, Appendix A.

BPI has not received consent from Royal Bank to release the remaining debt agreements (which correspond to borrowings 2 and 3 in Appendix 2-OB -2013 as filed in the evidence). This lender is requesting that its debt agreements be held in confidence. The reasons for requesting confidential treatment of these agreements are documented in BPI's cover letter to these interrogatory responses and in a communication from the lender setting out the need for confidentiality, which appears as an attachment to the cover letter.

Below is a chart showing how the filed agreements correspond to the debt instruments filed in Appendix 2-OB (2013).

Row	Description	Lender	Document Name	Notes
1	Promissory note	The Corporation of the City of Brantford	Already Provided	
2	Powerline Municipal Transformer Station Borrowings	Royal Bank	RBC Credit Facility Agreement (2010) and Amending Letters (2012 and 2013)	Please note that items 2 and 3 collectively correspond to "Facility #3"
3	Tier 2 Capital Project Borrowing	Royal Bank		
4	General borrowings	Ontario Infrastructure & Lands Corporation	Financing Agreement 07Bra904087070FA (Dec 3, 2007)	
5	General borrowings	Ontario Infrastructure & Lands Corporation	Amending Agreement 09Bra904109027FA (Nov 16 2010)	This amending agreement represents a combination of a former 2009 agreement and new 2010 borrowings. This represented $4,800,000 related to 2009 and 2010 capital expenditures combined. In addition to these General Borrowings this document contains the approval of $5,538,000 for smart metering which was issued in 2012. BPI only issued $5,531,000 of the approved amount.
6	Smart meter borrowings	Ontario Infrastructure & Lands Corporation		
7	General borrowings	Ontario Infrastructure & Lands Corporation	Financing Agreement 11Bra904101107FA, (Nov 27 2012)	

Exhibit 7 – Cost Allocation

7.0 Energy Probe-29

Ref: Exhibit 7, Tab 1, Schedule 1

The evidence indicates that BPI does not record the cost of service drops for USL, Street Lighting, Sentinel Lighting or Embedded Distributors in account 1855 and further that it does not record the cost of service drops on underground General Service assets in account 1855.

a) Does this mean that BPI has no costs associated with these service drops or that BPI has recorded the costs in an account or accounts other than 1855?

Response: BPI's has no costs associated with these service drops. BPI's practice is to recover the costs for these service drops through Billable Work Orders, which are ultimately a cost to the customer.

b) If BPI does have costs that are recorded in some account or accounts other than 1855, how does BPI allocate the costs so that they are only allocated to the proper classes?

Response: Following the practice described in section a) above, BPI does not have any such costs.

7.0 VECC – 36

Reference: Exhibit 7, Tab 1, Schedule 1, page 2

a) Where does BPI record the cost of service drops for USL, Street Lighting, Sentinel Lighting, Embedded Distributor and underground GS assets?

Response: BPI does not incur any costs for these service drops. For further detail of how these service drops are treated, please refer to the response to 7-Energy Probe-29.

b) What are the estimated 2013 values (Gross Book and Accumulated Depreciation) for the services?

Response: As there are no BPI costs associated with these services, there is no estimated 2013 value associated with them.

7.0-VECC – 37

Reference: Exhibit 7, Tab 1, Schedule 2, pages 3-4
Cost Allocation Model, Tabs I2, I6.1.

a) Please explain why there is no kWh value attributed to the Embedded Distributor Class (Tab I6.1).

Response: BPI's embedded distributor, Brant County Power (BPC), is billed directly and separately for it kWh purchases by the IESO based on usage measured on BCP owned meters.

As a result, BPI does not have kWh data for its Embedded Distributor Class, nor is this data necessary for determining revenues for the class (which are the focus of Tab 16.1) as the class is billed only through charges per kW.

b) When was BPI's Standby rate last adjusted?

Response: BPI's Standby rate was last adjusted in 2012, as a result of its 2012 IRM Application (EB-2011-0147). BPI's Standby rate was initially set prior to deregulation and has been adjusted in BPI's IRM processes since.

c) Please explain fully how BPI's standby charges are applied and provide an example of how the monthly charge is calculated.

Response: Each Standby customer reserves a base level of capacity (in kW) on the BPI system through an agreement with BPI. This typically represents the level of generation at a generation facility owned by the customer.

The capacity is reserved in order to guarantee the customer availability of system capacity; so that this customer can receive the energy it needs if its generation facility goes offline. For every month that the customer's demand level is below this reserved capacity, the customer's standby charge is for the capacity it has reserved. If the customer's demand surpasses its reserved capacity on the BPI system in any month, this becomes the reserved capacity to which standby rates are applied for the following year, unless the customer surpasses this new level during this year. If the reserved capacity level is not surpassed for a year, the reserved capacity amount resets to the base level in the customer's agreement with BPI.

Here is an example of how the monthly charges are calculated, using example data to illustrate the billing process:

Assumptions Used:					
Contracted Reserved Capacity: 3000 kW					
Standby Rate: $1.6729/ kW Reserved					
Example Monthly Standby Rate Calculation -2 Years*					
Year	Month	Metered kW Demand	Standby kW Billed	Explanation	Amount Charged = Reserved Capacity * Standby Rate
2014	Jan	1800	3000	contract reserved capacity	$ 5,018.70
2014	Feb	1550	3000	contract reserved capacity	$ 5,018.70
2014	Mar	1800	3000	contract reserved capacity	$ 5,018.70
2014	Apr	3100	3100	Apr 2014 demand has exceeded the contracted reserve capacity; This amount becomes the reserved capacity for a year	$ 5,185.99
2014	May	2900	3100	reserved capacity set in April 2014	$ 5,185.99
2014	Jun	3150	3150	June 2014 demand has exceeded th resereved capacity set in April 2014, this amount becomes the new reserved capacity for a year	$ 5,269.64
2014	Jul	2500	3150	reserved capacity set in June 2014	$ 5,269.64
2014	Aug	2600	3150	reserved capacity set in June 2014	$ 5,269.64
2014	Sep	1900	3150	reserved capacity set in June 2014	$ 5,269.64
2014	Oct	1700	3150	reserved capacity set in June 2014	$ 5,269.64
2014	Nov	1600	3150	reserved capacity set in June 2014	$ 5,269.64

2014	Dec	2700	3150	reserved capacity set in June 2014	$ 5,269.64
2015	Jan	2900	3150	reserved capacity set in June 2014	$ 5,269.64
2015	Feb	1000	3150	reserved capacity set in June 2014	$ 5,269.64
2015	Mar	2500	3150	reserved capacity set in June 2014	$ 5,269.64
2015	Apr	1900	3150	reserved capacity set in June 2014	$ 5,269.64
2015	May	1700	3150	reserved capacity set in June 2014	$ 5,269.64
2015	Jun	1600	3000	Reserved capacity is reset to the contracted reserved capacity- it has been a year since it was increased in June 2014 and it has not been surpassed since.	$ 5,018.70
2015	Jul	2700	3000	contract reserved capacity	$ 5,018.70
2015	Aug	2900	3000	contract reserved capacity	$ 5,018.70
2015	Sep	1000	3000	contract reserved capacity	$ 5,018.70
2015	Oct	2500	3000	contract reserved capacity	$ 5,018.70
2015	Nov	1800	3000	contract reserved capacity	$ 5,018.70
2015	Dec	1550	3000	contract reserved capacity	$ 5,018.70
* Please note this is an example created to illustrate how the Standby Charge is applied. It is not based on actual customer data.					

c) How was the 2013 expected revenue from Standby charges determined?

Response: The expected revenue from Standby charges was determined using the contract amount of reserved capacity. This amount is 3,000 kW per month, which equates to 36,000 kW per year. This has been multiplied by the applied-for Standby rate of $1.6729/ kW of reserved capacity to reach a forecast of $60,224 Standby revenues for 2013.

7.0 VECC – 38

Reference: Exhibit 7, Tab 1, Schedule 2, page 5

a) Please explain more fully why the additional revenue from the Sentinel Light class is used to reduce the ratio for the Embedded Distributor when the ratios for other customer classes are above and further away from 100%.

Response: BPI has used the additional revenue from the Sentinel Light class to bring the Embedded Distributor Class to 100% in order to be consistent with the Board's Decision and Order in the Brant County Motion (EB-2009-0063):

"The Board accepts the argument advanced by Brant County and will fix the rate based on a revenue-to-cost ratio of one." (page 5)

Exhibit 8 – Rate Design

8 Staff-30

Ref: E8, T1, Appendix B – RTSR Workform

Board staff notes that BPI has prepared its RTSR Workform using 2012 UTRs and Sub-Transmission rates.

On December 20, 2012 the Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2013, as shown in the following table:

2013 Uniform Transmission Rates

Network Service Rate	$3.63 per kW
Connection Service Rates	
Line Connection Service Rate	$0.75 per kW
Transformation Connection Service Rate	$1.85 per kW

The Board also approved new rates for Hydro One Sub-Transmission class RTSRs effective January 1, 2013 (EB-2012-0136), as shown in the following table.

2013 Sub-Transmission RTSRs

Network Service Rate	$3.18 per kW
Connection Service Rates	
Line Connection Service Rate	$0.70 per kW
Transformation Connection Service Rate	$1.63 per kW

a) Please complete a new RTSR workform using the UTRs and Sub-Transmission rates in effect for 2013.

Response: The RTSR Workform has been updated accordingly and can found as Attachment P.

8.0 Energy Probe-30

Ref: Exhibit 8, Tab 1, Schedule 1

Please provide a version on Table 8.9 that uses actual data from 2008 through 2012.

Response: BPI has completed the following table as requested:

		Historical Years					5-Year Average
		2008	2009	2010	2011	2012	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	1,013,423,330	940,830,205	950,759,113	944,902,732	964,379,231	962,858,922
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1,008,890,381	936,617,083	946,540,017	940,754,877	960,155,703	958,591,612
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	0	0	0	0	0	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	1,008,890,381	936,617,083	946,540,017	940,754,877	960,155,703	958,591,612
D	"Retail" kWh delivered by	977,884,255	912,366,781	917,169,662	915,803,475	931,554,498	930,955,734
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	0	0	0	0	0	-
F	Net "Retail" kWh delivered by distributor = **D - E**	977884255	912366781	917169662	915803475	931554498	930,955,734
G	Loss Factor in Distributor's system = **C / F**	1.0317	1.0266	1.0320	1.0272	1.0307	1.0297
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0364	1.0312	1.0367	1.0319	1.0353	1.0343

8.0 VECC – 40

Reference: Exhibit 9, Tab 3, Schedule 1, pg. 9

a) Is the Smart Meter Disposition rider a credit to customers? If yes, why does BPI propose a longer recovery period than 1 year?

Response: Yes the Smart Meter Disposition rider is a credit to residential customers and a debit to GS < 50 kW customers. Please see 9-Staff-39 (a) response for corrected proposed SMDRs.

Furthermore, BPI has requested to dispose this amount over a 4 year period because BPI is also requesting to recover as a debit to customers, costs related to stranded meters. Offsetting the stranded meter rate rider with the smart meter disposition rate rider over the 4-year recovery period will reduce the bill impact to its residential customers.

Exhibit 9 – Deferral and Variance Accounts

9.0 Staff-31

Ref: Exhibit 9, Tab 2, Schedule 1, Page 10-11, Account 1582

BPI is seeking recovery of the December 31, 2012 balance in Account 1582 in the amount of $353,252.

BPI states that totals for 2002-2004 would have been included in the 2006 EDR recovered amount in 1580. However, since BPI reallocated these amounts from Account 1580 to Account 1582, BPI reduced future recoveries of Account 1580 balances.

The Board ordered final disposition of all of the BPI deferral and variance account balances in its 2006 EDR, and Accounts 1580 and 1582 were disposed of on a final basis.

a) Did BPI obtain Board approval to reallocate balances from the accounts that were disposed of on final basis?

Response: BPI did not obtain Board approval to reallocate the balances from Account 1580 to Account 1582. However, this matter was identified to Board staff during its audit conducted in 2007. A copy of correspondence received from Board staff dated August 27, 2007 setting out the results of the audit review of regulatory balances is attached as Appendix # to this document. The reallocation of balances is discussed at item 2.3b on page 8.

b) Please confirm that the amount reallocated from Account 1580 to 1582 that was already disposed of on final basis was a debit of $211,246.13 (total of the amounts for the years 2002, 2003, and 2004, shown on page 11)

Response: BPI confirms that the amount reallocated from Account 1580 to 1582 that was already disposed of on final basis was a debit of $211,246.13 (total of the amounts for the years 2002, 2003, and 2004.

c) Please provide alternative rate rider calculations after removing the $211,246.13 and all related carrying charges from Account 1582.

Response: While BPI is of the view that the amounts booked to Account 1582 should be passed through to the ratepayers, BPI has provided the requested alternative rate rider calculations after removing the $211,246.13 and $73,156.05 carrying charges from Account 1582 in the tables below.

Table 9.11: 2013 Deferral and variance Account Rate Rider by Class

Customer Class	Group 1 Variance Accounts	Group 2 Variance Accounts	Total of Accounts 1562 & 1592	Total Variance Accounts	Billing Determinnents Projected 2013 KWh	Projected 2013 KW	Recovery Period (Years)	Rate Rider
Residential	$ (1,494,173)	$ 336,334	$ (20,601)	(1,178,440)	280,913,502	-	1	$ (0.0042)
GS< 50 kW	$ (518,788)	$ 116,778	$ (7,153)	(409,163)	97,535,297	-	1	$ (0.0042)
GS> 50 kW	$ (2,829,579)	$ 636,931	$ (39,014)	(2,231,662)	531,977,718	1,354,270	1	$ (1.6479)
Unmetered Scattered Load	$ (7,738)	$ 1,742	$ (107)	(6,103)	1,454,727	-	1	$ (0.0042)
Sentinel Lighting	$ (2,359)	$ 531	$ (33)	(1,860)	443,490	1,356	1	$ (1.3718)
Street Lighting	$ (40,174)	$ 9,043	$ (553.9)	(31,685)	7,553,004	23,455	1	$ (1.3509)
Total	$ (4,892,811)	$ 1,101,359		(3,858,913)	919,877,738	1,379,081		

Table 9.12: 2013 Non-RPP Global Adjustment Rate Rider by Class

Customer Class	Total Variance Accounts	Projected 2013 Non-RPP KWh	Projected 2013 Non-RPP KW	Recovery Period (Years)	Rate Rider
Residential	$ 65,816	36,518,755	-	1	$ 0.0018
GS< 50 kW	$ 17,578	9,753,530	-	1	$ 0.0018
GS> 50 kW	$ 709,485	393,663,512	1,002,159	1	$ 0.7080
Unmetered Scattered Load	$ 2,622	1,454,727	-	1	$ 0.0018
Sentinel Lighting	$ 799	443,490	1,356	1	$ 0.5894
Street Lighting	$ 13,612	7,553,004	23,455	1	$ 0.5804
Total	$ 809,913	449,387,018	1,026,971		

9.0 Staff-32

Ref: Exhibit 9, Tab 2, Schedule 5 – Request for Accounting Order for IFRS Impacts

BPI is requesting two deferral accounts effective January 1, 2014, as follows:

- Deferral Sub-Account "Impact of Gains or Losses on Disposition of Property Plant and Equipment of Account 1508 – Other Regulatory Assets
- Deferral Sub-Account "Other Post-Employment Benefits of Account 1508 – Other Regulatory Assets

<u>Deferral Sub-Account "Impact of Gains or Losses on Disposition of Property Plant and Equipment of Account 1508 – Other Regulatory Assets</u>

On page 23 of the Addendum to Report of the Board (EB-2008-0408) Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment, dated June 13, 2011 it states:

> *At the first cost of service application after the transition, a utility will be expected to provide a forecast of asset useful lives, and gains and losses from retirements, as part of its application.*

a) Given that BPI has not yet transitioned to IFRS, and its application is based on CGAAP, please provide the rationale for this account.

Response: The rationale for this account is based primarily on the fact that BPI expects to transition to IFRS during the course of the subsequent IRM period. As the test year budget is prepared using CGAAP, those accounting standards do not require the recognition of gains or losses from early retirements of pooled Property Plant and Equipment with the result that such assets are not removed from rate base until they have been fully amortized.

Under this accounting policy, ratepayers contribute to the full costs of these assets in annual increments over the expected useful lives as represented by the annual amortization charges. These amounts approximate the proportion of useful life that is consumed by customers on an annual basis. Similarly, any salvage value would be credited to accumulated amortization with the result that residual disposal benefits would be returned to customers in the form of reduced annual amortization charges caused by the net reduction in Property Plant and Equipment.

With the transition to IFRS, BPI will be required to recognize any gains or losses which occur at the date such assets are removed from service. During the IRM period, annual adjustments to distribution rates will reflect only the underlying CGAAP accounting policies contained in this cost of service rate application. As a result of the cost of service being determined using CGAAP, the resulting distribution rates were, by design, expected to recover asset utilization of pooled assets through the useful lives via orderly annual amortization charges.

With the introduction of IFRS, the requirement to immediately recognize gains or losses on disposition will have the result that the distribution rates adjusted during the IRM period will not reflect the impact of early retirement gains or losses as no such provisions were made in BPI's cost of service application prepared using CGAAP.

BPI contends that this inconsistency represents an undesirable outcome for both BPI and the Customers and the impact is directly the consequence of changing accounting framework outside the timeframe of a full cost of service rate application. Consequently, an accounting order allowing BPI to track the actual disposition gains or losses occurring after transition to IFRS will allow the Board to address such differences for disposition at the next cost of service distribution rate application enabling both BPI and customer interests to be addressed with the benefit of knowing the actual impact of this accounting framework change.

Although the deferral will delay the reflection of early retirements in requested distribution rates, BPI's proposal will ultimately allow an accurate reflection of the impact of this change on BPI's actual cost of service for any pooled Property Plant and Equipment disposed prior to the end of their useful lives. Furthermore, as this issue is only caused by the timing of the transition to IFRS, subsequent cost of service applications will not require this deferral treatment as the cost of service at that time will reflect forecast of such dispositions in keeping with the requirements of the IFRS framework in effect at that time and the established history of such early retirements.

BPI believes it would be inconsistent with the notion of just and reasonable rates to recognize in distribution rates a cost of service under an existing CGAAP accounting framework and not address the reality that there is a pending change to the IFRS accounting framework that will result in a change in the measurement of cost of service with respect to gains or losses on disposal of pooled Property Plant and Equipment. As BPI has harmonized the other elements of IFRS (capitalization policy and useful lives) on Property Plant and Equipment in this application, BPI submits that its proposal of a deferral account for this remaining element not harmonized until IFRS is actual adopted, is appropriate and in the interest of both BPI and the Customers.

Since the current Cost of Service incorporated in BPI's rate application does not reflect any provision for gains or losses related to early retirements of property plant and equipment, BPI believes the use of a deferral account is appropriate to capture the impact of this change in accounting framework.

As the current application intended such gains or losses to be deferred until the next cost of service application, BPI submits that should the Board not support the deferral concept in this instance, that BPI be allowed to amend its application to reflect a prorated provision reflecting the recognition of forecasted gains or losses on early retirements expected for the period after the adoption of IFRS until the next Cost of Service Rate Application. Without this application adjustment, BPI's cost of service recognized in this application would not be reflecting in its base revenue requirement the impact of early Property Plant and Equipment retirements once BPI transitions to IFRS.

b) Has BPI done an analysis of the historical gains and losses from early retirements? If so, how material are the annual amounts?

Response: BPI has attempted to determine the historical gains or losses from early retirements. Unfortunately, since these calculations were not required under existing CGAAP, BPI has not been able to extract from its records the information necessary to reliably establish the historical pattern for such early retirements.

As early retirements are typically the result of customer initiated requirements and not initiated by BPI e.g. unexpected municipal road widening, BPI expects that such amounts will occur annually and could fluctuate significantly from year to year depending on the nature, frequency and timing of such requests.

Prior to determining the test year budget under CGAAP, BPI had begun to prepare a test year budget under IFRS and provided for an estimate of $100,000 for the impact of losses from early retirement. However, given the inability to forecast based on history, this figure represented BPI's initial estimate based on judgment.

c) What is the regulatory precedent for the proposed Deferral Sub-Account "Impact of Gains or Losses on Disposition of Property Plant and Equipment of Account 1508 – Other Regulatory Assets?

Response: BPI is not aware of specific regulatory precedent in favour of this proposal. BPI submits that it is an unusual situation where the basis of accounting used to determine the cost of service incorporated into proposed distribution rates is subsequently changed outside of the timetable of the next full cost of service application.

To disallow the proposed deferral account will have the impact of predetermining that distribution rates determined as just and reasonable under a cost of service measured under CGAAP will automatically be just and reasonable under revised measurement of cost of service calculated under IFRS as it relates to impacts of gains or losses on early retirement of Property Plant and Equipment.

BPI submits that to predetermine this outcome in this proceeding without evidence of expected impact based on valid historical trending is inconsistent with the primary objective of establishing just and reasonable rates. BPI's proposal establishes a deferral account which allows the actual impact of this accounting change to be measured over the period following IFRS to the next cost of service application. At that time, with the availability of complete information relating to the nature, frequency and value of such adjustments, the Board will be in a position to determine the appropriate disposition of such amounts taking into consideration the actual impact of the change and the respective interests of BPI and the ratepayers.

d) Please provide justification for this account demonstrating the probability of significant volatility or PP&E derecognition expense. Please comment on addressing this expense through a *Z* factor application during the IRM period.

Response: With respect to probability, BPI submits that such adjustment will occur on an annual basis. As outlined above, such early retirements are typically initiated by customers related to installation of new services, upgrades to existing services or changes resulting from roadway widening or realignments. In some cases, such early retirements could be initiated by BPI to deal with unanticipated circumstances where

distribution system changes are deemed necessary to maintain the integrity or reliability of the distribution system. Although BPI attempts to repurpose assets that need to be removed where possible or feasible, such projects invariably result in the decommissioning of distribution assets that cannot be repurposed.
Since this work will ultimately depend on the frequency and timing of such projects, BPI expects there will be significant volatility in such PP&E derecognition expenses from one fiscal period to the next. Furthermore, the value of such adjustments will ultimately depend on frequency, nature and extent of these projects largely related to customer initiated requests.

With respect to the use of a Z factor application during the IRM Period, BPI notes that the principles of causation, prudence and materiality that apply to the establishment of new Deferral and Variance accounts also apply to z-factor applications. Those principles may apply to certain but not all circumstances requiring the early retirement of assets. For example, such early retirements that are initiated by customers related to installation of new services, upgrades to existing services or changes resulting from roadway widening or realignments may meet the z-factor criteria.

Further BPI notes the following from the Board's Report on *Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*:

> *A Z-factor has been incorporated into the incentive regulation mechanism for well-defined and well-justified cases only – **specifically, Z-factors will be limited to changes in tax rules and to natural disasters.***
>
> *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors , Appendix C, Page V, December 20, 2006.*

BPI is not aware of any successful z-factor application involving circumstances other than changes to tax rules and to natural disasters, since 2006.

In addition, BPI's submits that using the deferral account proposal for disposition considerations during the next Cost of Service Rate Application would simplify the regulatory process required to address the matter as it would form part of an existing planned proceeding and be evaluated with complete and accurate data regarding the impact of this change

<u>Deferral Sub-Account "Other Post-Employment Benefits of Account 1508 – Other Regulatory Assets</u>

On page 15 of the Addendum to Report of the Board (EB-2008-0408) Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment, dated June 13, 2011 it states:

> *The Board will not approve the creation of a generic account for IFRS related impacts on P&OPEB accounts occurring at the date of transition. As acknowledged by the CLD, the impacts are anticipated to be significant for only a few large utilities. The option remains for the utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.*

e) Given that BPI has not yet transitioned to IFRS, and its application is based on CGAAP, please provide the rationale for this account.

Response: The rationale for this account is based on two factors. Firstly, BPI expects to transition to IFRS during the course of the subsequent IRM period. As the test year budget is prepared using CGAAP, those accounting standards allow for the amortization of actuarial gains or losses in excess of 10% of the beginning accrued benefit obligations to expenses on a straight line basis over the expected remaining lifetime of inactive members receiving benefits under the plan. IFRS requires BPI to immediately recognize actuarial gains and losses as they occur with any transitional adjustment to the obligations to be recognized at the time of transition to IFRS.

Secondly, with the restructuring of BPI in early 2012, BPI has assumed the direct responsibility for the post-employment benefit obligations for additional 55-60 active employees. As all the employees transferred to BPI were formerly City of Brantford employees, the claims experience of active and retired employees were embedded into a much larger pool of employees for the City of Brantford. As a result, there is no reliable information available to BPI to predict the specific benefit claims rate for this group of employees as their pattern of experience may be different from the larger pool of City of Brantford Employees. With BPI employees formerly representing a relatively small proportion of the City of Brantford’s total employee group, it is possible that BPI employees reflect significant deviations in benefit claim patterns than is reflected in the total larger group as the relative smaller size of BPI employees could be easily blended into the experience pattern of the larger group which incorporates individuals from diverse occupations in varied industry sectors working for the City of Brantford.

Notwithstanding the Board's previous reliance on CLD's acknowledgement that large gains or losses would only likely occur in a few large utilities, that comment only addresses the general transition to IFRS and would not necessarily reflect the unique circumstances in BPI. Furthermore, the notion of "large gains or losses" from a CLD's perspective must take into consideration the relative size of the larger LDC's. BPI's materiality threshold for rate-setting purposes of $70,000 for OM&A is much smaller in absolute value Given the combination of IFRS transition and the potential of experience gains or losses resulting from BPI's 2012 restructuring, the impact to BPI in any given year could exceed this materiality level.

Furthermore, the notion that "*the impacts are anticipated to be significant for only a few large utilities"* is speculation and there is no evidence to support the fact that medium and smaller LDC's could not be proportionately affected. BPI recognizes that the impact to it can be expected to be smaller in absolute value than what is possible in a CLD, but the possibility of proportional impacts which could be significant to BPI remains a real possibility.

With BPI's additional risk of volatility resulting from the 2012 organizational restructuring, BPI is at a higher risk of being impacted by such actuarial gains or losses than typical LDC's regardless of size as they would not have recently added through restructuring a significant number of employees who were previously members of a larger actuarial group.

With the transition to IFRS, BPI will need to recognize any actuarial gains or losses immediately as they occur. During the IRM period, annual adjustments to distribution rates will reflect only the underlying CGAAP accounting policies contained in this cost of service rate application. Given the uncertainty related to future actuarial gains or losses, BPI reflected in its cost of service application only the premiums expected to be paid to secure such benefits. As a result, the proposed Cost of Service **excludes** any other components of the actuarially determined benefit expenses including interest and experience gains or losses on future employee benefits recognized under CGAAP or IFRS.

The premise of the proposal is that BPI captures in the proposed deferral account the variance between the actual impact of changes to the Obligation for Post-Employment benefits and the premiums actually disbursed until the next cost of service rate application.

Stated more clearly, BPI's proposal was crafted to allow the proposed distribution rates to cover the expected cash flow of providing these benefits until the next cost of service application when sufficient history and claims experience will be known to establish a suitable "all in" benefit expense for the servicing of BPI post-employment benefits. It is explicitly proposing to defer all other components of post employment "benefit expense" before and after converting to IFRS pending the accumulation of actual claims experience data and determining their future impact on the Obligation for Post Employment benefits under either CGAAP and IFRS.

BPI contends that to disallow the deferral approach in BPI's instance given its unique circumstances represents an undesirable outcome for both BPI and the Customers. As there is not the ability at this time to establish a full benefit expense value that can be supported with sufficient evidence. BPI believes it is appropriate to limit in its Cost of Service application the proposed recoveries of actual premiums reflected in the 2013 Test Year and defer all other elements of post employment benefit expenses for future disposition once the impacts are determined.

The inability to address the impact of changing accounting framework outside the timeframe of a full cost of service rate application and the impact of inadequate history post restructuring to establish a base line level of claims experience for BPI's newly acquired employee group, in BPI's submission is exactly the type of circumstance where a deferral account in warranted.

Consequently, an accounting order allowing BPI to track the actual variances in actuarially determined benefit expenses against the actual premiums paid will allow the Board to address such differences for disposition at the next cost of service distribution rate application. In this manner, distribution rates will ultimately reflect for both BPI and the Customers the actual actuarial benefit costs for eligible employees.

This proposed treatment would only be required for this IRM term, as subsequent cost of service applications will not require this deferral treatment as the cost of service at that time will reflect reliable forecasts of actuarial benefit expense in keeping with the requirements of the IFRS framework in effect at that time.

BPI believes it would be inconsistent with the notion of just and reasonable rates to recognize in distribution rates a cost of service under an existing CGAAP accounting framework and not address the reality that there is a pending change to the IFRS accounting framework that will result in a change in the measurement of the cost of service for actuarial gains or losses on Employee Future Benefit Obligations. In addition, the inability to accurately determine the claims experience of BPI's actual employee group is a major restriction to determining a realistic forecast of annual benefit expense and resulting Obligations for Future Employee Benefits under either CGAAP or IFRS.

BPI's proposal is attempting to include for recovery in distribution rates the premiums paid for Post-Employment benefits. As the valuation and measurement of actuarial benefit expenses under CGAAP and IFRS will require actual trending in claims utilization, it is not possible to reliably determine such amounts. BPI submits that its proposal of a deferral account to capture these variances until the next cost of service application is appropriate and in the interest of both BPI and the Customers.

f) Please comment on addressing this expense through a *Z* factor application during the IRM period.

Response: Please refer to the response to 9-Staff-32 d), above.

9.0 Staff-33

Ref: Exhibit 9, Tab 3, Schedule 1, Table 9.16 – Costs per Smart Meter

a) Do the costs per smart meter, by type, shown in Table 9.16 include the installation costs, or are these solely the meter purchase price?

Response: Yes, costs per smart meter in Table 9.16 include installation costs.

9.0 Staff-34

Ref: Exhibit 9, Tab 3, Schedule 1 – Beyond Minimum Functionality Costs

On page 2 of the exhibit, BPI states that it has not incurred any capital or OM&A costs for capabilities that exceed minimum functionality. The Smart Meter Model shows no "Beyond Minimum Functionality" costs.

On page 8 of the exhibit, under Time-of-Use billing, BPI documents that it transitioned to TOU billing in late 2011, with bills received by customers after December 15, 2011 being on a TOU basis. BPI notes that a communication package was sent to customers in October 2011 in preparation of TOU implementation.

As documented in *Guideline G-2011-0001 – Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), issued December 15, 2011, and in the Smart Meter Model, costs for TOU implementation are "beyond minimum functionality". Capital costs are recorded under 1.6.3, and OM&A costs are recorded under 2.5.2 on sheet 2 of the Smart Meter Model.

a) Please provide the costs for TOU implementation by year.

Response: The costs for TOU implementation by year are set out in the table below.

2008	2009	2010	2011
$ -	$ -	$ -	$ 35,018.80

b) Are these costs included in the deferred revenue requirement for smart meter costs? If not, how has BPI recovered, or is BPI proposing to recover, these costs?

Response: Yes these costs were included in the deferred revenue requirement for smart meter costs.

9.0 Staff-35

Ref: Smart Meter Model Ver. 3.0, Sheet 3- Cost of Capital

BPI has the following inputs for the cost of capital parameters on sheet 3 of its Smart Meter Model:

	2006	2007	2008	2009	2010	2011	2012	2013
Cost of Capital								
Capital Structure[1]								
Deemed Short-term Debt Capitalization			4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	44.0%	44.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Preferred Shares	0.0%							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters								
Deemed Short-term Debt Rate			4.47%	1.33%	2.07%	2.46%	2.46%	2.08%
Long-term Debt Rate (actual/embedded/deemed)[2]	5.80%	5.80%	6.10%	7.62%	5.87%	5.32%	5.32%	4.03%
Target Return on Equity (ROE)	9.0%	9.00%	8.57%	8.01%	9.85%	9.58%	9.58%	8.93%
Return on Preferred Shares								
WACC	7.21%	7.21%	7.02%	7.52%	7.31%	6.91%	6.91%	5.91%

The Board's Decision EB-2007-0698 in BPI's 2008 cost of service application approved the following cost of capital parameters:

Capital Component	% of Total Capital Structure	Cost (%)
Short-term Debt	4.0	4.47
Long-term Debt	49.3	6.04
Common Equity	46.7	8.57
Total	100.0	

For the purposes of calculating the deferred revenue requirement on smart meters, the Board-approved cost of capital rates from BPI's last cost of service application should apply until this application for 2013 rates. The capital structure evolved to the current 56% long-term debt, 4% short-term debt and 40% equity through the k-factor and would have been completed by 2010. However, the starting point in 2006 for a utility of BPI's size was 50% debt and 50% equity.

a) Please confirm the cost of capital parameters approved for BPI in its 2006 EDR application considered under RP-2005-0020/EB-2005-0342.

Response: BPI has confirmed the cost of capital parameters approved for BPI in its 2006 EDR application and updated the smart meter model accordingly.

b) Please make the necessary corrections to the smart meter model to incorporate the approved capital structure and cost of capital.

Response: BPI has made the necessary corrections to incorporate the approved capital structure and cost of capital to the smart meter model that is attached as Attachment Q.

9-Staff-36

Ref: Smart Meter Model Ver. 3.0, Sheet 3 – Tax Rates

BPI has shown the following rates for taxes/PILs for calculated the deferred revenue requirement for smart meters:

	2006	2007	2008	2009	2010	2011	2012	2013
Taxes/PILs								
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.50%	26.50%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%	0.00%

a) Please confirm that these rates correspond with the aggregate Federal and Ontario Corporate Income Tax rates underpinning rates for each year.

Response: Yes these rates correspond with the aggregate Federal and Ontario Income Tax rates for each year.

b) Please update the smart meter model if required.

Response: No Tax Rates update required to the smart meter model.

9.0 Staff-37

Ref: Smart Meter Model, Ver. 3.0, Sheets 2 and 8A – OM&A Expenses

a) BPI documents $314,199 in OM&A expenses from 2006 to 2013 on sheet 2 of the Smart Meter Model, but documents $272,199 on sheet 8A. Please reconcile these numbers.

Response: The number on sheet 2 ($314,199) does not match the documented amount ($272,199) on sheet 8A because sheet 8A formula (cell K122) is only summing up cells K25:K108. BPI respectfully request Board staff to correct the formula in cell K122 to sum-up cells K25:K120 as the cell is protected by Board Staff. Once the update is done, cell K122 amount on sheet 8A will be $314,199 and the numbers will be reconciled.

b) Please explain why BPI only shows depreciation expenses for December 2010 and December 2011 on sheet 8A.

Response: BPI began recording depreciation expense for smart meters in December 2010 when the Board provided their guidance on how LDCs should treat smart meter depreciation expenses for regulatory purposes.

The Board provided this guidance in its Accounting Procedures Handbook Frequently Asked Questions dated December 2010 and BPI implemented the new procedures starting with the 2010 year end.

BPI has also updated Sheet 8A of the smart meter model to include depreciation expenses for December 2012 and December 2013. OM&A expenses on sheet 8A (column K) for 2013 are actuals for January to September and forecast for October to December.

9-Staff-38

Ref: Smart Meter Model, Ver. 3.0 – Sheet 9

Board staff notes that BPI has not selected either of sheet 8A (cell C35) or sheet 8B (cell C37) for purposes of including the interest on OM&A and depreciation expense for calculating the deferred smart meter revenue requirement. Board staff further notes that Sheet 8A is preferable as it is based on more detailed monthly data and calculations, but sheet 8B is a reasonable proxy.

a) Please select one of the two sheets through the drop-down list in cells C35 or C37.

Response: BPI agrees with Board Staff's preference to Sheet 8A and made the selection in cell C35 accordingly.

9.0 Staff-39

Ref: E9, T3, S1, Table 9.21 & Appendix D – Smart Meter Model – Sheet 10A

BPI calculates the following Smart Meter Disposition Riders ("SMDRs"): ($0.19)/month for Residential and ($0.77)/month for GS < 50 kW customers, both to be credited over a period of four years.

Board staff notes that historically customers in all metered customers paid a common Smart Meter Funding Adder ("SMFA") and the higher average costs per meter for GS customers relative to Residential customers means that the deferred revenue requirement should be higher also for GS customers. This would appear to indicate that the SMDR for the Residential class should be less than that for the GS < 50 kW class.

A review of sheet 10A indicates that BPI has allocated the SMFA revenues based on the capital-weighted meter costs. In previous Board Decisions, the Board approved an allocation of SMFA revenues based on customer numbers, with the SMFA revenues for metered customer classes that did not receive smart meters (e.g. GS > 50 kW) allocated equally between the classes that did receive the smart meters (Residential and GS < 50 kW, in BPI's case).

a) Please update the Smart Meter Model for an allocation of SMFA revenues based on customer numbers and to reflect any other corrections made in response to other interrogatories by Board staff and intervenors. Please file any corrected Smart Meter Model and proposed SMDRs; the Smart Meter Model should also be filed in working Microsoft Excel format.

Response: BPI has updated sheet 10A of the Smart Meter Model to reflect the allocation of SMFA revenues based on customer numbers and refilling the Smart Meter Model in working Microsoft Excel format. Below are BPI's corrected proposed SMDRs credited (residential class) and debited (GS < 50 KW class) over a period of four years:

Proposed SMDRs	
Residential	$ (0.46)
GS<50 kW	$ 2.78

Stranded Meters

9.0 Staff-40

Ref: Exhibit 9, Tab 4, Schedule 1 – Stranded Meters

BPI documents its proposal for the Stranded Meter Rate Rider ("SMRR") in this exhibit. Table 9.22 documents the net book value of conventional Residential and GS < 50 kW meters stranded through replacement by smart meters, and Table 9.23 documents the calculation of the proposed SMRRs.

Board staff has replicated Table 9.22 following, including calculating the gross book value ("GBV") and NBV per meter, based on the 38,128 smart meters installed for Residential and GS < 50 kW customers. This shows a GBV of $138.34 per stranded conventional meter and a NBV remaining to be recovered averaging $84.90.

Table 9.22: Stranded Asset Values

Year	Gross Asset Value	Accumulated Amortization	Contributed Capital	Net Asset	Proceeds on Disposition	Residual Net Book Value
2006				$ -		$ -
2007				$ -		$ -
2008				$ -		$ -
2009	$ 953,530	-$ 359,800		$ 593,730		$ 593,730
2010	$ 3,978,550	-$ 1,521,728		$ 2,456,822	-$ 3,781	$ 2,453,041
2011	$ 342,720	-$ 150,854		$ 191,866	-$ 1,446	$ 190,420
2012				$ -		$ -
	$ 5,274,800	-$ 2,032,382	$ -	$ 3,242,418	-$ 5,227	$ 3,237,191

Number of Smart Meters Installed (from Table 9.23)

38,128

Cost per Stranded Conventional Meter

	Gross Book Value	Net Book Value
	$ 138.34	$ 84.90

Board staff is also attaching a copy of sheet I7.1 – Meter Capital Costs from the Cost Allocation Model filed in BPI's 2008 cost of service application EB-2007-0698. Sheet I7.1 documents a Residential GBV average cost of $57.58, a GS < 50 kW GBV per meter of $178.38 and an average GBV per meter for all meter customer classes of $95.51. Board staff notes that BPI is proposing to recover a remaining NBV from Residential customers of $85 per meter, which is higher than the original GBV of $57.58 for Residential customer meters.

a) Please confirm that the attached sheet I7.1 corresponds with the Cost Allocation model from BPI's 2009 cost of service rates application. In the alternative, please provide a copy of sheet I7.1 from the correct Cost Allocation model.

Response: BPI confirms that attached sheet I7.1 with Board's interrogatories submitted on September 25, 2013 corresponds with the Cost Allocation model from BPI's 2008 cost of service rates application.

b) Please explain how BPI has derived the costs shown in Table 9.22. In particular, why are the costs significantly higher than the capital-weighted meter costs per meter for the Residential customer class and for all installed meters?

Response: The total costs for the capital-weighted meter costs used in the cost allocation study that supported the 2008 rate application were not reconciled to the actual balances in 1860. The actual 1860 balances used in the cost allocation study were 2004 values. The total from Sheet I7.1 for Weighted Metering Costs was $3,339,380. BPI's actual balance in 1860 according to the 2.1.7 OEB Trial Balance filing for 2004 was $5,113,746. This difference would impact the capital-weighted meter costs per meter that is being used to compare the stranded meter costs to.

The change in capitalization policy in 2006 would also contribute to the higher cost per meter for all installed meters. During the period 2006-2008, BPI capitalized $294,575 of indirect costs which would be factored into the cost of the stranded meters.

c) Please explain how BPI did the accounting for tracking the GBV, accumulated depreciation and depreciation expense for the stranded conventional meters.

Response: During 2009, BPI determined the cost of the meters to be replaced through review of postings into the meter capital work orders and year end working paper files. The accumulated amortization to December 31, 2008 was calculated based on these costs.

BPI did not historically differentiate meter capital by customer class. Costs for meter capital additions were reviewed for years 2002 to 2008 from work order data to determine the split between meters that were not slated for replacement and meters to be replaced based on the material postings. The trending of the split between stranded and non-stranded costs for 2002-2008 was applied to years prior to 2002 to estimate the total costs of meters to be stranded.

A query was developed to extract the meter counts from the CIS system. This data detailed the meters by class that were eligible for regulatory deferral account treatment by year of installation.

An average cost and accumulated amortization calculation for meters to be stranded was done for each of the years of addition. Accumulated amortization was updated annually to reflect an additional year of amortization on the meters that had not been changed yet.

Monthly queries were analyzed to determine the change in number of meters by install date to determine the number of meters that were changed that month. A journal entry reallocating the corresponding cost and accumulated amortization of the meters that were stranded during the month were posted to the stranded meter general ledger account.

d) Please provide an asset continuity schedule from 2008 to 2013 that documents how BPI separated the asset values and accumulated depreciation for the stranded conventional meters from wholesale and GS > 50 kW meters also recorded in Account 1860 – Meters.

Response: The table below provides BPI's asset continuity schedule from 2008 to 2013 documenting how BPI separated the asset values and accumulated depreciation for the stranded conventional meters from wholesale and GS > 50 kW meters also recorded in Account 1860 – Meters.

Capital Meters			# of years									
1860			25									
							ANNUAL AMORTIZATION					
Year	Total Meter Capital Costs	Stranded Meters	Adjusted Total Costs	Accum Amort to 2008	Stranded Meters	Accum Amort to 2008 - adj	2009	2010	2011	2012	Total Accum to 2012	NBV @ 2012
	a	b	c=a+b	e	f	g=e+f	h	i	j	k	m=g+h+i+j+k	NBV=c+m
2000	$ 4,054,582.07	$ (3,040,937.00)	$ 1,013,645.07	$ (1,324,501.07)	$ 993,368.41	$ (331,132.66)	$ (40,545.80)	$ (40,545.80)	$ (40,545.80)	$ (40,545.80)	$ (493,315.86)	$ 520,329.21
2001	$ 223,240.53	$ (167,431.00)	$ 55,809.53	$ (71,447.53)	$ 53,586.62	$ (17,860.91)	$ (2,232.38)	$ (2,232.38)	$ (2,232.38)	$ (2,232.38)	$ (26,790.43)	$ 29,019.10
2002	$ 222,734.92	$ (167,051.00)	$ 55,683.92	$ (62,372.92)	$ 46,788.12	$ (15,584.80)	$ (2,227.36)	$ (2,227.36)	$ (2,227.36)	$ (2,227.36)	$ (24,494.24)	$ 31,189.68
2003	$ 230,059.36	$ (168,975.56)	$ 61,083.80	$ (55,221.36)	$ 40,558.09	$ (14,663.27)	$ (2,443.35)	$ (2,443.35)	$ (2,443.35)	$ (2,443.35)	$ (24,436.67)	$ 36,647.13
2004	$ 383,129.29	$ (160,426.84)	$ 222,702.45	$ (76,629.29)	$ 32,089.09	$ (44,540.20)	$ (8,908.10)	$ (8,908.10)	$ (8,908.10)	$ (8,908.10)	$ (80,172.60)	$ 142,529.85
2005	$ 575,112.47	$ (408,559.38)	$ 166,553.09	$ (92,007.47)	$ 65,372.66	$ (26,634.81)	$ (6,662.13)	$ (6,662.13)	$ (6,662.13)	$ (6,662.13)	$ (53,283.33)	$ 113,269.76
2006	$ 810,537.63	$ (725,729.42)	$ 84,808.21	$ (97,275.63)	$ 87,096.40	$ (10,179.23)	$ (3,392.33)	$ (3,392.33)	$ (3,392.33)	$ (3,392.33)	$ (23,748.55)	$ 61,059.66
2007	$ 460,739.05	$ (330,297.80)	$ 130,441.25	$ (36,849.05)	$ 26,416.57	$ (10,432.48)	$ (5,217.65)	$ (5,217.65)	$ (5,217.65)	$ (5,217.65)	$ (31,303.08)	$ 99,138.17
2008	$ 259,720.20	$ (217,698.62)	$ 42,021.58	$ (10,408.20)	$ 8,708.07	$ (1,700.13)	$ (1,680.86)	$ (1,680.86)	$ (1,680.86)	$ (1,680.86)	$ (8,423.57)	$ 33,598.01
2009	$ 424,756.19		$ 424,756.19	$ -	$ -	$ -	$ (16,990.25)	$ (16,990.25)	$ (16,990.25)	$ (16,990.25)	$ (67,961.00)	$ 356,795.19
2010	$ 1,092,290.88		$ 1,092,290.88	$ -	$ -	$ -		$ (43,691.63)	$ (43,691.63)	$ (43,691.63)	$ (131,074.89)	$ 961,215.99
2011	$ 413,338.02		$ 413,338.02	$ -	$ -	$ -			$ (16,533.52)	$ (16,533.52)	$ (33,067.04)	$ 380,270.98
2012	$ 158,376.78		$ 158,376.78	$ -	$ -	$ -				$ (6,297.07)	$ (6,297.07)	$ 152,079.71
Total	**$ 9,308,617.39**	**$ (5,387,106.62)**	**$ 3,921,510.77**	**$ (1,826,712.52)**	**$ 1,353,984.03**	**$ (472,728.49)**	**$ (90,300.21)**	**$ (133,991.84)**	**$ (150,525.36)**	**$ (156,822.43)**	**$ (1,004,368.33)**	**$ 2,917,142.44**
Stranded Meters												
1555												
2000	$ -	$ 3,040,937.00	$ 3,040,937.00	$ -	$ (993,368.41)	$ (993,368.41)	$ (121,637.48)	$ (121,637.48)	$ (121,637.48)	$ (121,637.48)	$ (1,479,918.33)	$ 1,561,018.67
2001	$ -	$ 167,431.00	$ 167,431.00	$ -	$ (53,586.62)	$ (53,586.62)	$ (6,697.24)	$ (6,697.24)	$ (6,697.24)	$ (6,697.24)	$ (80,375.58)	$ 87,055.42
2002	$ -	$ 167,051.00	$ 167,051.00	$ -	$ (46,788.12)	$ (46,788.12)	$ (6,682.04)	$ (6,682.04)	$ (6,682.04)	$ (6,682.04)	$ (73,516.28)	$ 93,534.72
2003	$ -	$ 168,975.56	$ 168,975.56	$ -	$ (40,558.09)	$ (40,558.09)	$ (6,759.02)	$ (6,759.02)	$ (6,759.02)	$ (6,759.02)	$ (67,594.17)	$ 101,381.39
2004	$ -	$ 160,426.84	$ 160,426.84	$ -	$ (32,089.09)	$ (32,089.09)	$ (6,417.07)	$ (6,417.07)	$ (6,417.07)	$ (6,417.07)	$ (57,757.37)	$ 102,669.47
2005	$ -	$ 408,559.38	$ 408,559.38	$ -	$ (65,372.66)	$ (65,372.66)	$ (16,342.38)	$ (16,342.38)	$ (16,342.38)	$ (16,342.38)	$ (130,742.18)	$ 277,817.20
2006	$ -	$ 725,729.42	$ 725,729.42	$ -	$ (87,096.40)	$ (87,096.40)	$ (29,029.18)	$ (29,029.18)	$ (29,029.18)	$ (29,029.18)	$ (203,213.12)	$ 522,516.30
2007	$ -	$ 330,297.80	$ 330,297.80	$ -	$ (26,416.57)	$ (26,416.57)	$ (13,211.91)	$ (13,211.91)	$ (13,211.91)	$ (13,211.91)	$ (79,264.21)	$ 251,033.59
2008	$ -	$ 217,698.62	$ 217,698.62	$ -	$ (8,708.07)	$ (8,708.07)	$ (8,707.94)	$ (8,707.94)	$ (8,707.94)	$ (8,707.94)	$ (43,539.83)	$ 174,158.79
Scrap sale	$ (3,781.31)		$ (3,781.31)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,781.31)
Scrap sale	$ (1,446.24)		$ (1,446.24)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,446.24)
Total	**$ (5,227.55)**	**$ 5,387,106.62**	**$ 5,381,879.07**	**$ -**	**$ (1,353,984.03)**	**$ (1,353,984.03)**	**$ (215,484.26)**	**$ (215,484.26)**	**$ (215,484.26)**	**$ (215,484.26)**	**$ (2,215,921.07)**	**$ 3,165,958.00**

9.0 Staff-41

Ref: Exhibit 9, Tab 4, Schedule 1 – Stranded Meters

In *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), issued December 15, 2011, the Board states its expectation that proposals for the SMRR would reflect an allocation of the stranded meter costs reflecting the net book value of the conventional meters stranded by replacement by smart meters. In Section 3.7, page 22, of Guideline G-2011-0001, the Board states:

> *The distributor should determine and support its proposed allocation, based on the principles of cost causality and practicality. The stranded meter NBV should be recovered through rate riders for applicable customer classes. A distributor must outline the manner in which it intends to allocate the stranded meter costs to the applicable customer rate classes and the rationale for the selected approach. If a distributor has recorded the NBV of the stranded meters by customer class, it should propose class-specific rate riders for each applicable class (Residential, GS < 50 kW and any other classes approved by the Board for smart meter deployment). If the NBV is not known on a class-specific basis, a distributor should propose an allocation between the affected metered customer classes and support its proposal.*

In Table 9.23, BPI documents its proposed SMRRs. It appears that the NBV of stranded meters is allocated based on the number of smart meters installed in each of the Residential and GS < 50 kW classes, and then the allocated amounts are recovered by the average number of Residential and GS < 50 kW customers forecasted in the 2013 test year.

Board staff observes that this is equivalent to an unweighted allocation, whereby no differences in the capital costs of meters installed in each class is taken into account. In particular, the higher prices of polyphase meters, which are more prevalent for GS customer classes, are not taken into account.

a) Please explain the rationale for BPI's proposed allocation.

Response: BPI has corrected its proposed allocation based on Sheet I7.1 provided by Board Staff. This will result in an allocation of 81% residential and 19% GS < 50 kW.

b) Based on the information provided in the response to 9-Staff-47 and Sheet I7.1 from BPI's 2008 Cost of Service application, please clearly document the methodology for allocating the costs between the classes. Where available, spreadsheets for documenting the data and calculations should be provided in working Microsoft Excel format.

Response: As a follow-up to 9-Staff-41 (a) response, below is a recalculated allocation of costs between the classes. $3,165,958 is the actual NBV of the stranded meters at the end of 2012. On the other hand, $3,237,191 in table 9.22 shown above in 9.00 Staff-40 was the NBV at the end of 2011. The difference is during 2012 BPI recorded the remainder of the smart meters to be stranded and recorded 2012 amortization (as well as some corrections to the amortization account between 1860 and stranded).

	Residential	GS < 50 kW	Total
Allocation Percentage	81.0%	19.0%	100%
Stranded Asset Balance to be Recovered	$ 2,564,426	$ 601,532	$ 3,165,958
Number of Customers - 2013 Forecast	35,364	2,764	38,128
Rate Rider - 1 Year	$ 6.04	$ 18.14	
Proposed Rate Rider - 4years	**$ 1.51**	**$ 4.53**	

c) BPI's application is for a 2013 test year. However, BPI filed its application on July 17, 2013 and has proposed an effective date of November 1, 2013. In the meantime, BPI continues to recover the return of capital (i.e., depreciation expense) and return on capital of stranded conventional meters in its current approved distribution rates. Please provide a variation on the response to b), above, assuming recovery of the SMRR beginning January 1, 2014, and recovery of depreciation expense of conventional meters for the full year 2013.

Response: Assuming the recovery of SMRR beginning January 1, 2014, BPI's recovery of depreciation expense of conventional meters for the full year 2013 would be $215,484.26. Therefore, the NBV at the end of 2013 will be $3,165,958.00 - $215,484.26 = $ 2,950,473.74. Below table provides a variation from the response to 9-Staff-41 (b):

	Residential	GS < 50 kW	Total
Allocation Percentage	81%	19%	100%
Stranded Asset Balance to be Recovered	$ 2,389,884	$ 560,590	$ 2,950,474
Number of Customers - 2013 Forecast	35,364	2,764	38,128
Rate Rider - 1 Year	$ 5.63	$ 16.90	
Proposed Rate Rider - 4years	**$ 1.41**	**$ 4.23**	

9.0 Energy Probe-31

Ref: Exhibit 9, Tab 2, Schedule 1 &
Exhibit 9, Tab 2, Schedule 5

There is a balance of $670,257 in account 1508 Other Regulatory Assets - Sub-Account - Other that is proposed to be recovered in 2013 (Exhibit 9, Tab 2, Schedule 1). This amount is called an under-recovery from the embedded distributor over the September, 2008 to December, 2012 period.

In Exhibit 9, Tab 2, Schedule 5, Table 9.8 shows that this amount, along with other Group 2 amounts, is allocated to all rate classes <u>except</u> the Embedded Distributor class based on kWh.

a) Please explain why any other rate class should be paying for the under-recovery from the Embedded Distributor class.

Response: The balance of $670,257 in account 1508 Other Regulatory Assets - Sub-Account – Other relates to the difference between the GS > 50 kW distribution rates that BPI was approved to charge its Embedded Distributor as a result of its 2008 rates case and the embedded distributor rate that was determined as a result of the *Brant County Motion (EB-2009-0063)* with the Board.

At Exhibit 9, Tab 2, Schedule 1, page of 6 of BPI's current application, BPI referred to the Board decision order in the BCPI matter which stated that:

> *Accordingly, the difference between the existing approved GS > 50 kW rate and the new Brant County rate times the Brant County volumes for the relevant period should be tracked in a variance account for recovery at Brantford's next rebasing. The Board notes that Brant County has no objection. (Pages 14 and 15).*

That is, BPI has not under-recovered from its Embedded Distributor class; instead BPI under-recovered distribution revenue from the other classes as a result of the difference between the GS>50kW rate and the embedded distributor rate approved in 2009.

b) Please explain why there is no allocation to the Embedded Distributor class shown in Tables 9.7 & 9.8.

Response: BPI has not allocated any regulatory asset amounts to the Embedded Distributor class, consistent with the Rate Order in the Brant County Motion (EB-2009-0063), and the Tariffs of Rates and Charges approved by the Board in BPI's subsequent IRM proceedings.

9.0 Energy Probe-32

Ref: Exhibit 9, Tab 4, Schedule 1

a) Please explain how BPI has calculated or estimated the net book value of the stranded meters for each of the residential and GS < 50 rate classes.

Response: Please see 9-Staff-40 (c) response.

b) Please provide a table that shows the allocation and the resulting rate riders if the remaining net book value of the stranded meters is based on the same relative meter costs as used in the 2008 cost allocation approved by the Board.

Response: Please see 9-Staff-41 (a) & (b) response.

8.0 VECC – 39

Reference: Exhibit 9, Tab 4, Schedule 1/Excel Spreadsheet Chapter 2 Appendices Links Broken_20130717

a) Please reconcile the stranded gross asset value of $5,274,800 show in Table 9.22 with the amount of $5,269,572 shown in the 2012 Excel spreadsheet Continuity Statement for 2012.

Response:

Table 9.22	$	5,274,800
2012 Continuity Schedule	$	5,269,572
Difference	**$**	**5,228**

The $5,228 difference is the proceeds on the sale of scrap that was recorded to the regulatory accounts but not to the PP&E accounts.

b) Please provide the gross residential and gs<50 meter additions to account 1860 made in years 2009 through 2012.

Response: BPI does not differentiate customer classes when tracking costs to capital accounts. BPI reviewed postings to meter capital identifying meters that typically service residential and GS<50KW customers. Additions other than meters were allocated on a pro-rata basis. BPI estimates the additions to 1860 during the period 2009 through 2012 that service Residential and GS<50KW customers to be $687,000.

c) Please explain why Table 9.22 shows an increase in the gross value of stranded meters from 2009 to 2010.

Response: Table 9.22 shows an increase in the gross value of stranded meters from 2009 to 2010 because BPI recorded the meters as stranded as they were removed from service.

ATTACHMENT A

REFERENCE: 1.0 SEC 1

DATE: January 24, 2013 **REPORT NO. BPI-1301-003**

TO: Chair and Directors

FROM: Brian D'Amboise, Chief Financial Officer

1.0 TYPE OF REPORT: ☒ **For Decision**

☐ **For Discussion**

☐ **For Information**

2.0 TOPIC: 2013 BUDGET APPROVAL

3.0 RECOMMENDATIONS

That the Brantford Power Inc. (BPI) Board of Directors:

a) Approve the proposed 2013 Budget and Multi-Year forecast and recommend its approval to the Brantford Energy Corporation Board of Directors;

b) Approve the 2013 Budget particulars where applicable as the basis for BPI's 2013 Test Year Budget with respect to the 2013 Cost of Service Distribution Rate Application;

c) Direct Management to update the 2013 Budget and Multi-Year Forecast for the further consideration of the Board should the ongoing discussions between Management and the City of Brantford regarding transfer pricing arrangements result in significant amendments being required.

4.0 PURPOSE

To present to the Board of Directors for approval a proposed 2013 Budget and Multi-Year forecast with background and explanatory information. The approval of this budget will establish the basis of the 2013 Test Year Budget to be reflected in the 2013 Cost of Service Distribution Rate Application.

5.0 BACKGROUND

Management presents annually to the Board for approval, a proposed budget for the next year and the financial forecasts for the subsequent four years. The 2013 Budget is also significant as it will form the basis of the 2013 Test Year Budget to be reflected in the 2013 Cost of Service Distribution Rate Application.

In this regard, Management reviewed with the BPI Board at its September 2012 Board meeting a summary illustration of the current budgetary expectations under various distribution rate adjustment scenarios. A subsequent draft 2013 Budget was posted on the Board's FTP site in early November 2012 so the Board could be updated on the progress made to date and review specific issues regarding the current budgetary plan. As further update was presented and discussed at the December 2012 Board meeting.

At this stage, Management has reviewed all of the departmental operating and capital budget submissions and incorporated them into the plan. Management has resolved the outstanding items reflected in the previous draft circulated for the information of the Board of Directors.

This proposal reflects the impact of the City of Brantford's proposed Transfer Pricing arrangements as presented by the City and interpreted by BPI Management. It is important to note that the Regulatory Department has completed their analysis of the Transfer Pricing Report and is currently engaged in a dialogue with the City of Brantford to obtain where required, clarification on the proposed Transfer Pricing arrangements and to ensure it is in keeping with BPI's requirements.

As the establishment of a 2013 Test Year Budget is one of the most significant prerequisites to completing a Cost of Service Distribution Rate Application, Management is recommending the approval of the 2013 Budget and Multi-Year Forecast in order to avoid any further delays in completing and filing the 2013 Cost of Service Distribution Rate Application.

As the discussions with the City of Brantford have not yet been completed, it is possible this dialogue could result in an amendment to the proposed 2013 Budget and Multi-Year Forecast although the likelihood of such a requirement is not determinable at this time. As a result, Management believes it is in BPI's interest to proceed with budget approval at this time to allow BPI to proceed with the significant activities necessary to complete the 2013 Cost of Service Distribution Rate Application.

Should the dialogue with the City identify the need for amendments, Management will assess the significance and materiality of such changes to determine if a formal budgetary amendment is warranted.

Should the changes result in a change exceeding $250,000, Management will present for the subsequent consideration of the Board, an amended 2013 Budget and Multi-Year Forecast highlighting the nature and magnitude of the changes. Otherwise, the revisions will be reflected in the 2013 Cost of Service Distribution Rate Application and the approved budget will continue to reflect the official financial plan for 2013 and deviations will be reported as explainable variances.

As it is not possible to determine with certainty the level of distribution revenues BPI could attain following the rate application. Management has illustrated the new base revenues beginning in 2014 on the basis of a maximum 10% increase on existing distribution rates. As it is anticipated BPI's 2013 rate decision will be received late in the year, the 2013 revenues have assumed a continuation of the current rates.

It is important to note, that the Cost of Service Distribution Rate Application determines the revenue requirement deficiency that BPI may have on the basis of the 2013 budgeted rate base and related cost of service. The revenue figures reflected in the budget are illustrative of future revenues so Management can establish a base line financial plan for the review of the Board and the Company's financiers.

The essence of the 2013 Cost of Service Distribution Rate Application is for the OEB to determine the appropriateness of the calculated revenue deficiency. The ultimate level of distribution revenues and its consequential impact on the longer term financial plan can only be determined once the new level of distribution revenues have been established by the OEB and Management can assess the resulting funding availability for cost recovery and resulting business returns.

Consequently, Management needs to highlight to the Board that the determination of the longer term financial performance of BPI will be largely dependent on the extent the OEB has been convinced that the underlying costs of BPI are prudent and appropriate in the circumstances, are in keeping with industry norms or are supported by substantive evidence of unique circumstances in Brantford warranting special consideration. Put simply, the OEB must be convinced of BPI's cost justification in order to support a rate order that the BPI submitted distribution rates are just and reasonable.

Provided the Board of Directors approves the proposed budget, the Company is obligated to obtain the approval of its shareholder, Brantford Energy Corporation. It is anticipated this approval will be obtained at their next scheduled meeting on March 7, 2013.

6.0 INPUT FROM OTHER SOURCES

Not Applicable

7.0 STRATEGIC PLANNING CONTEXT

Where applicable, the 2013 Budget and Multi-Year forecast reflect provisions required to implement the strategies contained in the approved strategic plan.

8.0 ANALYSIS

8.1 ANALYSIS – INTRODUCTION

Management presented the previous iterations of the 2013 Budget Plan as works in progress as they were not considered complete pending the resolution of a few substantive issues. Management has addressed the outstanding issues by resolving them or by providing budgetary provisions for matters that cannot be resolved completely.

To provide the Board with continuity to the previous draft, the current Budget proposal have addressed the following previously outstanding activities in the following manner:

1) **IMPACT OF CITY OF BRANTFORD ARC COMPLIANCE ACTIVITES**

   This issue represented a significant item that impacted the 2013 Budget and Multi-Year forecast. The following will summarize the treatment of the applicable issue in the proposed 2013 Budget:

   a) **REVISED SLA AND UDPATED TRANSFER PRICING REGIME:** The proposed nature and value of shared services to be provided under a revised Service Level Agreement and the basis of the proposed ARC compliant transfer pricing regime is assumed to be in keeping with the proposal received from the City of Brantford. As previously mentioned, discussions are ongoing and should material amendments be required, a revised 2013 budget proposal could be submitted for the consideration of the Board of Directors.

   b) **OTHER ISSUES RELATING TO BPI RESTRUCTURING:** Since the last Budget draft, the previously outstanding items have been resolved. The following represents an update on the status of these matters:

      i) The City Treasurer has indicated that assets to be transferred have been fully depreciated and consequently have no book value. Based on this, BPI has not reflected any financial transaction related to such transfer of assets in 2012. The City plans to formally transfer such assets on December 31, 2012.

         The City and BPI are currently compiling a listing of BPI acquired assets. It has recently been identified that the City of Brantford may be carrying some limited book value on specific assets to be transferred. Management is waiting for clarification from the City as to whether this transfer will result in a financial transaction between the two entities.

If so, the 2012 projections would need to be updated to reflect this new information. It is not expected that this will have a material impact on the proposed financial plan.

Management has provided limited provisions in the 2013 Budget and Forecast Years to provide for some asset replacement contingencies.

ii) The current 2012 forecasts reflects the impact of the City of Brantford transferring $1,379,267 in reserve funding to BPI on November 23, 2012 related to vested sick leave, IT replacement and customer service equipment reserves. The budget reflects the receipt of these monies in 2012.

iii) Final decisions on transitional transfer pricing true ups following restructuring on April 1 where hybrid transitional relationships were created. Based on discussions with the City, interim true ups have been processed. The reported 2012 forecasts reflect what Management believes will be the costs incurred in 2012.

c) **UPDATED COST SHARING – BRANTFORD ENERGY GROUP OF COMPANIES:** The resolution of revised transfer pricing from the City is expected to impact the costing of some shared services within the Brantford Energy Group of Companies. With the expectation that the revised City SLA charges will be based on improved cost drivers, the share of expenses allocated to BPI and its affiliates are expected to change to be in keeping with the new drivers.

Also, as the Brantford Energy Corporation (BEC) Budget has yet to be completed, BPI has not yet received the proposed Management fees from BEC for 2013. The current budget proposal reflects provisions for such cost allocations and Management Fees based on historical levels. The Board should note however that based on OEB decisions in other rate cases, BPI will no longer be entitled to rate recovery of any Brantford Energy Corporation Management Fees in distribution rates.

2) MANAGEMENT REFINEMENTS OF BUDGETED AMOUNTS

Since the last Board meeting, Management has revised the 2013 Budget and Multi-Year Forecasts to take into account:

a) Better projections of 2012 year end amounts based on more recent actual data;

b) The revenue forecast used to extrapolate total revenues in Finance's budget modeling has been compared to the draft load forecast developed for the Cost of Service Distribution Rate Application. Finance has concluded the embedded load forecast calculations used in the budget modeling has resulted in a reasonable illustration of expected revenues.

With the resolution of the above matters, Management is satisfied that the budget proposal being presented has adequately addressed the outstanding issues which previously prevented the completion of the 2013 Budget and Multi-Year Forecasts.

8.2 ANALYSIS – DISTRIBUTION REVENUES

For 2013, the budget for distribution revenues reflects the current distribution rates without any adjustment under either the IRM rate adjustments or under Cost of Service rate adjustments. As the Test Year Budget will be the basis of determining the required revenue requirement, the final distribution revenue amount determined in the application will be those revenues determined in accordance with the OEB's filing instructions and models.

Notwithstanding the fact that it is expected that the Cost of Service Distribution Rate Application will request effective new rates as at May 1, 2013, past OEB rate decisions reflect the pattern that late applications typically result in delayed effective rates. As a result, the attached 2013 Budget is not reflecting any rate adjustments during 2013. This is the most conservative scenario and will demonstrate to the Board of Directors the impact on the current financial plan incorporating expected increased operating costs and the need to absorb into OM&A the impact of previously capitalized indirect overheads no longer permitted under IFRS.

Using this basis for determining Distribution Revenues, Details of the distribution revenue components have been reflected on Schedule F – Schedule of Commodity Recoveries and Other Revenues and Financial Expenses. In summary, the comparative distribution revenues can be summarized as follows:

Brantford Power Inc.
2013 Budget
Analysis of Distribution Revenues ($1,000)

Component	2011 Actual (GAAP)	2012 Budget (GAAP)	2012 Projected (GAAP)	2012 Budget (MIFRS)	2012 Projected (MIFRS)	2013 Budget (MIFRS)
Bases distribution Revenues	$15,026	$14,666	$15,003	$14,666	$15,003	$14,860
Embedded Distributor Rate Differential	132	139	130	139	130	129
Adj to revenue CDM Initiatives	-	-	-	-	-	58
Special Purpose Charge Rate Rider	-	-	-	-	-	-
Repayment of 2001-2006 PILS	-	(1,000)	(1,217)	(1,000)	(1,217)	(691)
LRAM rate rider	-	427	344	427	344	172
Total	**$15,158**	**$14,231**	**$14,260**	**$14,231**	**$14,260**	**$14,528**

As the 2013 Budget does not reflect any change in base distribution rates, the slight improvement in revenues is primarily attributable to removal of the negative rate rider attributable to the return of the 2001-2006 Deferred PILS which will end on April 30, 2013.

The 2014 Distribution rates reflect an increase of 10% mitigated increase to existing distribution rates. Although the 10% mitigation threshold is typically applied to the total bill impact, this approach provides further contingencies should BPI not be able to recover all costs submitted in the rate application.

The timing and quantum of actual distribution rates and revenues for 2014 will depend on the outcome of the Cost of Service Distribution Rate Application. Revenues beyond 2014 assume a 0.5% annual rate increase under IRM. Deviations from these forecasts are expected and the longer term financial plan may be impacted by the final decision of the OEB regarding this application.

Conservation and Demand Management (CDM)

There is no current basis to forecast the possible margins on various OPA CDM programs which is scheduled to be determined in 2015 when the true up of the 2011-2014 program cycle will be calculated. Consequently, all CDM transactions are assumed to be break even during the years in which the CDM programs are delivered. Consequently CDM program contributions are assumed to be Nil in 2012 and 2013. Although margins are expected to be achieved at the end of the program cycle, the forecast years continues to present a break-even position.

It should be noted that Management has calculated the allocation of indirect overheads to the OPA programs, the impact on Net Income is Nil. On the CDM programs, the impact is an increase of costs offset by corresponding increases in revenues. The budget assumes sufficient funding room will exist to absorb the increased costs. The impact on the rate application is that ratepayers will not be contributing via distribution rates to the shared costs allocated to CDM

Load Profile

The 2013 Budget assumes consumption levels, which are consistent with the recent annual average inclusive of the impacts of conservation programs. The consumption details have been summarized on Schedule K. Management has compared the load profile in its budget modeling to the current draft load profile prepared for the Cost of Service Distribution Rate Application and has concluded the revenue forecast contained in the budget is appropriate.

8.3 ANALYSIS – OPERATING COSTS

The 2013 Budget provides for gross operating costs totaling $9,449,000 on a gross or pre-allocated departmental basis (Schedule I) or a 5.6% per cent increase over the 2012 approved MIFRS budget. The 2013 budget represents a 6.8% increase over the 2012 projected MIFRS year-end position.

Among the highlights of the 2013 budget are the following items:

- Provision for salary and wage increases in accordance with negotiated settlements or anticipated increases and salary changes or lost cost sharing from the organizational changes resulting from the restructuring;
- Provision for staffing complement as summarized below:

Brantford Power Inc.
2013 Budget
Proposed Staffing Complement

Department (Note 1)	2011 Actual	2012 Budget	2012 Projected	2013 Budget
CEO	1	1	1.0	1.0
Engineering	9.5	10.25	9.0	10.0
Operations (Note 2)	17	17.25	19.0	19.65
Metering and Settlement	5.65	6	6.0	5.35
Regulatory and Administration	6	6	6.0	5
Finance (Note 3)	3.25	3.25	3.75	3.75
Conservation and Demand Management	1.85	2	2.05	2.05
Customer Service (Note 4)	20.13	20.13	12.33	12.33
Total	**64.38**	**65.88**	**59.13**	**59.13**

Note 1: *Where Director level positions provide oversight to multiple departments, the FTE amount reflects the share of the Directors contribution to the respective departments. Also, the FTE's for 2011 Actual and 2012 Budget reflects the FTEs previously found in the City of Brantford's Power Department where applicable.*

Note 2: *The Operations FTEs reflect the transfer of 3 FTEs from the City of Brantford's Purchasing Stores Department.*

Note 3: *The Finance Department reflects the absorption of a FT CFO and the transfer of 50% of the former City of Brantford Utility Accounting Group.*

Note 4: *The Customer Service figures for 2011 actual and 2012 budget reflects the numbers of staff in the combined Power/Water Utilities as there is no meaningful way to allocate the BPI share of previous staffing levels.*

- Operating costs reflect the direct cost of staff transferred resulting from the 2012 restructuring. Among these impacts include the following:
  - Absorption and annualization of FT CFO, Board Secretary related ancillary costs which were formally shared with other affiliates or City operations;
  - In the case of Customer Service, the 2013 reflects estimated annual costs for the separation of billing functions e.g. increase in postage and other increases attributable to the lost cost sharing with the City's water utility. Although the split bill is not expected until the second quarter, the budget reflects the anticipated annual cost as such costs will be the "new normal" and will need to be reflected in the Cost of Service Distribution Rate Application Revenue Requirement;
  - Staffing changes have been proposed in the Finance Department as the transfer of 2.0 FTE's or 50% of the former utility accounting group is insufficient to deal with the current accounting workload. Based on past cost allocation of costs prior to restructuring, the BPI share of the former utility accounting group exceeded 50% of the combined costs;

- The Engineering Department reflects an increased FTE although staying substantially within current budget envelope by introducing a comparable reduction in expected operating expenses.

- Provision of $100,000 towards the cost of the System Integration Study which under MIFRS will not qualify for capital expenditure treatment;
- Reflection of City of Brantford Service Level Agreement charges in keeping with their Transfer Pricing Proposal. The total SLA charges planned for 2013 is $2,872,000. This compares to the $6,847,000 budgeted in 2012 which reflected both the Power Department and other shared service charges prior to the restructuring.

The Board should review Schedule I, which provides a detailed reconciliation of the gross departmental costs as set out in this gross expense Schedule I to the net amounts reflected in Schedule H – Schedule of Direct and Indirect Expenses Net of Allocations. The functional totals on Schedule H, are carried forward to the Statement of Operations to the various operations, maintenance and administration line items.

It is important to note that beginning in 2013, there are no longer any indirect costs being charged to the capital program although indirect cost allocations are made to various operating accounts to reflect the fully absorbed functional costing required by the OEB. Such allocations have been updated to reflect where possible the Transfer Pricing Proposal cost drivers provided by the City of Brantford.

With respect to the increases in costs from the 2012 projected year end position, Management is presenting the following reconciliation of gross departmental costs by major departments. This reconciliation is made more challenging this year as 2012 projected costs contain a hybrid of pre and post restructuring costs as the majority of employee transfers were effective April 1, 2012:

Brantford Power Inc.
2013 Budget
Reconciliation of 2012 Projected (MIFRS) to 2013 Budgeted Gross Departmental Cost
By Responsibility Area ($1,000)

Description	Engineering & Operations			CEO		CFO		Regulatory		Total
	Opns	Eng.	Metering & Settlmt	CEO Office	Tranfrmr Station	Customer Service	Finance	SLA	Admin & Reg.	
2012 Projected (MIFRS)	**1,547**	**655**	**705**	**255**	**79**	**1,413**	**473**	**2,810**	**904**	**8,841**
Change in wages and benefits	(13)	12	19	(1)	12	375	27	-	6	**437**
Change in wages/benefits charged to capital	(29)	(107)	(21)	-	-	-	-	-	-	**(157)**
Increase in wages and benefits – vacant position	-	70	-	-	-	42	61	-	-	**173**
Provision for system integration study	-	-	-	-	-	-	-	-	96	**96**
Change in regulatory	-	-	-	-	-	-	-	-	12	**12**
Impact of splitting power and water billing	-	-	-	-	-	533	-	-	-	**533**
LEAP & Bad Debts	-	-	-	-	-	6	-	-	-	**6**
Changes in City SLA	(90)	(1)	-	-	-	(525)	(119)	(6)		**(741)**
Changes in prof fees, contracted services, staff development	(64)	41	54	18	9	50	87		26	**221**
Fleet recovery differences	248	-	-	-	-	-	-	-	-	**248**
Restructuring costs (2012)	-	-	-	**(41)**	-	-	-	-	-	**(41)**
Other	-	-	-	-	-	-	-	**(217)**	27	**(190)**
2013 Budget (MIFRS)	**1,599**	**670**	**757**	**231**	**100**	**1,894**	**529**	**2,587**	**1,071**	**9,438**
Percent Change	**3.3%**	**2.2%**	**7.4%**	**(9.5)%**	**27.8%**	**34.1%**	**11.9%**	**(7.9%)**	**18.5%**	**6.8%**

Note: With the 2012 projected figures reflecting in most cases 3 months of direct SLA charges and 9 months of direct BPI costs the reconciliation of the staffing component dollars is very difficult to capture in the rollforward.

Capitalization Policy

The 2013 Budget reflects the changes to the Capitalization Policy approved in 2012. As MIFRS no longer allows the capitalization of indirect overhead, Operations. Maintenance and Administration costs will be higher than those previously reported under Canadian GAAP.

Nevertheless, costs that are directly related to the capital program will continue to form part of the Company's capital expenditures as was the case before. The impact of this allocation process under MIFRS if using the 2012 experience as a reference point is the increase in operating expenses by $987,000. This increase is offset to a degree by a reduction in amortization expenses of $818,000 for a net impact of increasing costs approximating $169,000 in 2013.

8.4 ANALYSIS – CAPITAL PROGRAM

One of the challenges BPI had to face with the delayed rate rebasing is the ability of the Company to generate capital for the capital program. By the end of 2012, the impact of recent financing transactions plus the reduction in equity levels resulting from the assumption of post-employment obligations for transferred employees has resulted in the Company forecasting a projected MIFRS debt level of 59.2% and 59.0% in 2012 and 2013 respectively.

This level is above the Company's existing 57% capital structure guideline but is forecasted to return to the targeted range in 2014 at a level of 56.9%. The Board may recall that this policy provided for holding the additional 3% to the OEB's 60% deemed level in reserve to allow the Company to deal with unexpected circumstances where financing might be required. Since BPI capital structure in 2013 would approximate the OEB maximum level in 2013, the planned debt contingency room is not expected to be available again until 2014.

As a result of the lower level of earnings and the Company's 59.0% debt level, Management has reduced the level of the capital budget by $733,000 from the projected level of 2012 spending calculated under MIFRS.

Based on the current 2013 Budget, the expected financial performance for 2013 combined with this level of capital spending will result in a reduction of cash totaling $2.5 million before the consideration of any dividends to the shareholder.

The budget provides for a capital program in 2013 totaling $3.4 million as outlined on Schedule D. Schedule E summarizes the major capital projects planned by major project groupings.

Brantford Power Inc.
2013 Budget
Capital Expenditures Net of Contributed Capital ($1,000)

Item	2010 Actual (CGAAP)	2011 Actual (CGAAP)	2012 Budget (CGAAP)	2012 Proj. (CGGAP)	2012 Budget (MIFRS)	2012 Proj. (MIFRS)	2013 Budget (MIFRS)
Distribution Plant	5,376	4,054	4,685	4,586	3,494	3,566	2,678
General Plant	472	558	505	620	505	607	762
Total	**5,848**	**4,612**	**5,190**	**5,206**	**3,999**	**4,173**	**3,440**

No provision has been made for any acquisition of land or building for a new service centre or for other accommodation solutions in 2013 or beyond.

8.5 ANALYSIS – FINANCING PROGRAM

BPI finalized its smart metering financing during 2012 and also closed the additional $4,000,000 in deferred 2011 capital financing before the end of the fiscal year.

As outlined above, with the Company exceeding the targeted debt guideline in 2013, the 2013 Budget does not provide for any additional borrowings. Future levels of borrowings will ultimately depend on the level of future retained earnings. With no further recapitalization borrowings available, future borrowings will be limited to the amounts necessary to sustain the 57% debt levels.

Management has not reflected any future borrowings during the 2013 or forecast years at this time pending the outcome of the 2013 Cost of Service Distribution Rate Application. As BPI continues to pay down existing debt during the forecast years, BPI will create additional financing capacity beginning in 2015.

The financing costs are based on the existing debt portfolio reflecting the current actual rates. The current City promissory note of $24,189,000 was renewed on February 1, 2011. The Promissory Note currently earns the City 5.87% until 2016.

8.6 ANALYSIS – SHAREHOLDER PAYMENTS

Based on the results in the 2013 Budget, the following payments are forecasted

:

Brantford Power Inc.
2013 Budget
Summary of Shareholder Payments

Payments	2010 Actual	2011 Actual	2012 Projected	2013 Budget
Current year Promissory Note Interest (Note 1)	1,511,823	**1,427,564**	1,419,904	1,419,904
SLA 10% Mark Up (Note 2)	675,000	**Nil**	Nil	Nil
Dividends (Note 3)	750,000	**750,000**	750,000	305,000
Special Dividends (Note 4)	Nil	**700,000**	Nil	445,000
Subtotal Dividends	750,000	**1,450,000**	750,000	750,000
Total Payments	$2,936,823	**$2,877,564**	$2,169,904	2,169,904
Prior Year Reported Net Income	2,219,056	**1,873,456**	2,289,611	747,818
Total Dividend Payout % (Note 5)	33.8%	**77.4%**	32.8%	100.3%

Note 1: *The interest rate on promissory note is scheduled to be next updated effective February 1, 2016.*

Note 2*: The SLA amounts have been estimated and exclude any SLA contributions on the capital program. The 10% markup was eliminated on BPI SLA charges beginning in 2011.*

Note 3: *Pending the outcome of the 2013 Cost of Service Distribution Rate Application, the 2013 Budget and Multi-Year forecast reflects dividend payments for 2013 and beyond at current levels. Adjustment to these levels may be necessary once the outcome of the rate application is known.*

Note 4*: The special dividends reflect the level of additional dividends that is forecasted. These additional amounts reflect the return of excess cash in part due to recapitalization of the capital structure towards the target 57% debt amount. As 2013 is a transition year, the payment of total dividends of $750,000 is expected to result in a debt level of 59.0% which is higher than the targeted 57% level. Current forecast reflects a return to the targeted level by the end of 2014 following the rebasing of distribution rates.*

Note 5: *Dividend payout ratio is based on the current year payout divided over the prior year earnings.*

The Board should note that the payment of interest is directly to the City of Brantford and the dividends will be paid to the Brantford Energy Corporation, which will need to consider payment to the City.

9.0 FINANCIAL IMPLICATIONS

The 2013 financial plan outlined in the attached 2013 Budget reflects Management's best estimate of the expected 2013 BPI financial performance. There is no question that BPI is in need of revised distribution rates as the increasing costs incurred since 2008 not covered by annual IRM rate increases plus the need to absorb indirect overhead costs previously capitalized has virtually squeezed out all available returns. The forecast of no rate changes in the 2013 Budget illustrates that 2013 will be a financially challenging year.

Nevertheless, the current comfortable cash position and modest earnings projections for 2013 provides BPI with the ability to transition to 2014 where increased distribution revenues are forecasted. The current forecasts indicate however, that BPI's financial position would seriously deteriorate in 2014 without a successful and timely outcome to the 2013 Cost of Service Distribution Rate Application.

The following table summarizes the key highlights of the current version of the 2013 Budget:

Brantford Power Inc.
2013 Budget
Balance Sheet Highlights
($ Amounts in $1,000)

Factor	2011 Actual	2012 Budget (GAAP)	2012 Projected (GAAP)	2012 Budget (MIFRS)	2012 Projected (MIFRS)	2013 Budget (MIFRS)
Cash	9,200	9,071	13,871	9,071	13,871	**10,615**
Net Book Value of Capital Assets	63,352	65,143	64,519	61,575	61,162	**61,421**
Capital Expenditures (Net of Capital Contributions)	4,612	5,191	5,206	4,000	4,173	**3,440**
Net Regulatory Assets (Liabilities)	(3,183)	542	(462)	542	(462)	**1,492**
Promissory Note to City	24,189	24,189	24,189	24,189	24,189	**24,189**

Factor	2011 Actual	2012 Budget (GAAP)	2012 Projected (GAAP)	2012 Budget (MIFRS)	2012 Projected (MIFRS)	2013 Budget (MIFRS)
Long Term Debt	16,730	20,190	19,963	20,190	19,963	**18,925**
Retained Earnings	12,359	11,401	12,398	7,779	9,033	**8,633**
Current Ratio	2.0	1.9	1.8	1.9	1.8	**1.7**
Debt component of capital structure	54.8%	57.4%	56.7%	**60.1%**	59.2%	**59.0%**

- Cash levels will remain at minimal levels despite returning significant regulatory liabilities by the end of 2013 resulting in a return to a regulatory asset net position. The borrowing of $4,000,000 in 2012 has replenished the cash returned to customers to liquidate former regulatory liabilities. The base line cash levels are set to provide a current ratio below 1.5 and 2.0 times.
- The Net Book Value of Capital Assets is expected to increase to $61.4 million by the end of 2013. The growth rate in capital assets is much lower with the introduction of MIFRS as a result of the removal of significant indirect overhead costs from capital expenditures and the longer useful lives of distribution plant. The level of capital spending in 2013 was also reduced to reflect the amount of capital available to Brantford Power Inc. during 2013.
- Long Term Debt increased to $44.2 million by the end of 2012 due to the closing of the last installment of the Smart Metering financing and the $4,000,000 financing planned for the 2011 general capital program. As no new borrowings are planned for 2013 or during the forecast periods, the Long Term Debt is expected to decline to $43.1 million to reflect planned principal repayments.

  Borrowings beyond 2013 are not forecasted at this time pending the outcome of the 2013 Cost of Service Distribution Rate Application. Once the impact of the rate decision is known, BPI will be in a position to reflect a revised financial forecast which is expected to reflect new borrowings at that time.
- The Company’s’ working capital levels will reflect slight decline in 2013 resulting in a 1.7 current ratio by the end of the year. Since no borrowing room is currently available and BPI is not able to generate sufficient earnings to fund planned capital expenditures until rate rebasing is completed, 2013 is expected to reflect a year where cash and working capital levels decline by $3.3 million and $2.8 million respectively.

  Once the rebased revenues are known, Management will need to update multi-year forecasted levels of working capital to ensure that any deviations to the deemed 13% working capital allowance component of the rate bases is due to the particular cash flow requirements of BPI.

With respect to the Statement of Operations, the following highlights have been summarized:

Brantford Power Inc.
2013 Budget
Statement of Operations Highlights
($ Amounts in $1,000)

Factor	2011 Actual	2012 Budget (GAAP)	2012 Projected (GAAP)	2012 Budget (MIFRS)	2012 Projected (MIFRS)	2013 Budget (MIFRS)
Distribution Revenues	15,158	14,231	14,260	14,231	14,260	**14,528**
Operating Costs	6,991	7,857	7,918	8,916	8,820	**9,403**
Interest on Promissory Note	1,427	1,420	1,420	1,420	1,420	**1,420**
External Financing Costs	742	757	774	857	828	**978**
Income before PILS and Regulatory Impacts	3,060	1,026	1,031	1,002	1,048	**483**
Net Income	2,290	772	746	748	763	**350**
Return on Equity	6.7%	2.2%	2.1%	2.3%	2.3%	**1.1%**

- The budget reflects a projected 2012 GAAP Net Income of $746,000 which approximates the target set in the 2012 Budget. It is important to note however, that the approved budget did not contemplate any of the organizational changes implemented on April 1, 2012.
- The Net Income for 2013 reflects slightly improved distribution revenue due the completion of the negative PILS rate rider being complete at the end of April 2013. The budget reflects no changes to base distribution rates as the approved new cost of service rates are not expected until late in the year.
- The major changes in budgeted operating costs from 2012 are based on the IFRS accounting changes regarding indirect overheads plus the annualization and absorption of costs resulting from the restructuring.
- The company is forecasted to meet its banking covenant obligations during the 2013 Budget year and beyond. As there are no debt servicing covenants with RBC, and the Company's capital structure is below the OEB deemed levels, there are no RBC covenant issues.
- Assuming the final outcome of Transfer Pricing does not deviate materially from the current estimates, it is expected 2013 will result in a negligible Net Income. Nevertheless based on expected achievement of the 2012 performance target and a strong cash position, Management is forecasting a continuation in 2013 of the $750,000 dividend represented by a regular dividend of $305,000 and a special dividend of $445,000 representing further balance sheet recapitalization.

In summary, Management believes this 2013 budget version represents a conservative assessment of the expected financial performance for the next fiscal year. The trending of financial performance in recent years provides further evidence of the need to rebase BPI's distribution rates at the earliest possible opportunity.

8.7 FINANCIAL IMPLICATIONS – KEY RISKS

Other than normal budgetary variances which may arise, Management has identified the following critical risks to the 2013 Budget**:**

- **Affiliate Code Compliance Restructuring:** The budget proposal reflects the City of Brantford's Transfer Pricing Proposal as the basis of shared service costing in the 2013 Test Year Budget. In addition, the post restructured budgets reflect Management's best estimate of funding requirements for the new responsibilities assumed directly by the Company.

  As there is no history to base some of these projections, the actual future costs of the separated functions or the application of the revised transfer pricing mechanisms could result in unanticipated variances to the proposed budgets as these new processes are implemented and refined.

- **Capital Financing:** the 2012 forecast reflects the borrowing of $4,000,000 in 2012 new capital financing that was deferred from 2011 financing plans. Although the Company has temporarily exceeded its targeted debt level guideline of 57%, the continued pay down of principal and future earnings will establish new borrowing room and return the Company's debt level to the targeted range.

  The impact of delayed rate rebasing will likely impact lenders desire to provide BPI with new required capital until after the OEB has addressed the 2013 Cost of Service Distribution Rate Application. Lenders will need to determine what level of cost recovery is going to be provided to determine the level of free cash flows available for debt service purposes.

  Until such time as new borrowings are possible, funding of capital expenditures and dividends will need to be from internally generated funds. With the small returns currently being earned, the accumulation of capital will not be possible until rates have been rebased. Based on current timelines, new rates are not expected to be in place until 2014.

- **Distribution Revenues:** The 2013 forecasted distribution revenues reflect the continuation of current rates anticipating a Cost of Service rate adjustment decision late in 2013. Although no rate increases have been forecasted, the ultimate distribution revenues will depend on OEB decisions related to rate mitigation requirements and the level of cost recovery the OEB will allow in distribution rates.

Recent statements by the OEB Chair has indicated that the OEB does not see the Cost of Service Distribution Rate Application as a “cost plus” exercise but rather a process that allows the LDC to recover prudently incurred costs. There is no guarantee that the submitted costs will be determined to be prudently incurred unless BPI has submitted sufficient and appropriate evidence to substantiate the recoveries being requested. The Company will be in a much better position to assess the longer term financial prospects for the Company once the rebased rates are determined and BPI has achieved full compliance with the ARC.

10.0 CONCLUSION

Management believes that the revised 2013 Budget proposal represents a “bare bones” financial plan to carry the Company to the next generation of distribution rates. Consequently, Management is submitting this 2013 Budget and Multi-Year Forecast for approval.

Signed by:

Brian D’Amboise, CFO

Signed by:

Paul Kwasnik, CEO

ATTACHMENTS:

COPIES:

ATTACHMENT B

REFERENCE: 1.0 Energy Probe-1

DATE: **April 25, 2013** **REPORT NO. BPI-1304-005**

TO: **Chair and Directors**

FROM: **Brian D'Amboise, Chief Financial Officer**

1.0 TYPE OF REPORT:

☐ **For Decision**

☐ **For Discussion**

☒ **For Information**

2.0 TOPIC: INTERIM FINANCIAL STATEMENTS – FIRST QUARTER 2013

3.0 RECOMMENDATION

Not Applicable

4.0 PURPOSE

To provide highlights of the current Quarter's financial position and results of operations.

5.0 BACKGROUND

The quarterly interim financial statements of Brantford Power Inc. are presented with a covering report summarizing the current reporting highlights and to raise to the attention of the Board any additional related matters.

As a result of the decision made to file the 2013 Cost of Service Distribution Rate Application under Canadian Generally Accepted Accounting Principles (CGAAP), Management is reporting the 2013 operating results using CGAAP. As the budget was prepared using Modified International Financial Reporting Standards (MIFRS), the presentation of the budget has been updated to reflect CGAAP treatment without any changes to the underlying transactions contained in the MIFRS based approved budget.

In keeping with the Board's wishes to focus reporting on key trending, the report has been updated to provide a number of charts which will illustrate by quarter the trending on various financial attributes as well as the YTD results.

6.0 INPUT FROM OTHER SOURCES

Not Applicable

7.0 STRATEGIC PLANNING CONTEXT

Not Applicable

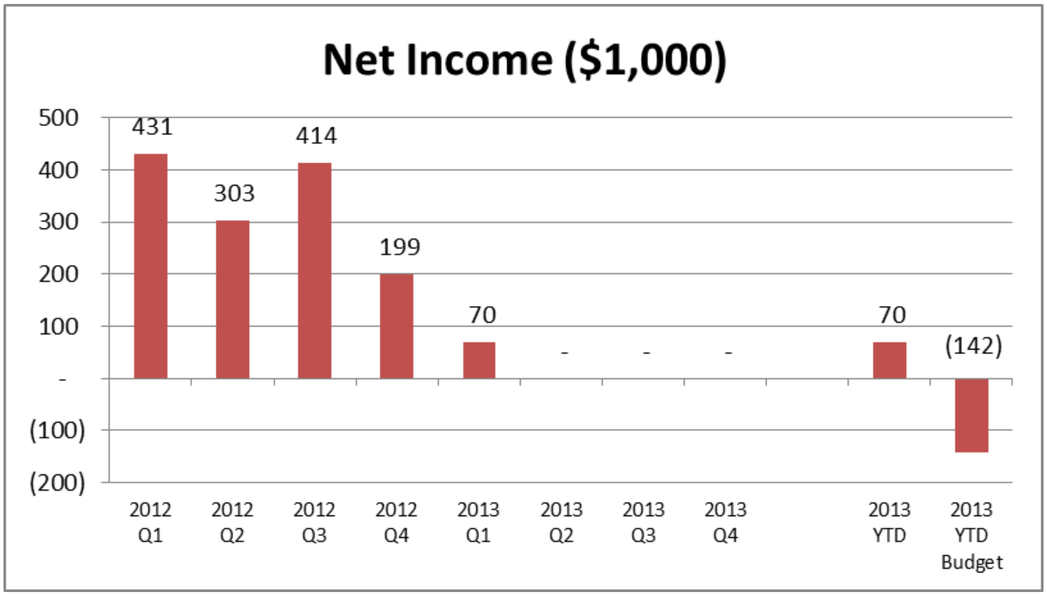
8.0 ANALYSIS

As these first quarter financial statements have just been completed, there are a number of unresolved matters that required the use of estimates until actual information becomes available. Deviations from these estimates once the actuals are known could impact the reported results. Among the key issues outstanding are the following:

- Not all of the quality assurance activities that the Finance Department performs with the beginning of a new year have yet to be completed. With the completion of the 2012 fiscal year end, these items are now priority and any adjustments identified will be reflected in the accounts before the release of Second Quarter results.
- The City has not invoiced BPI for any SLA charges for 2013 nor for any residual non SLA shared costs e.g. residual shared customer service costs. The Finance Department has estimated these charged using any available information or if none was available, charges were based on budgetary expectations.
- Estimated SLA charges for Treasury, Accounts Payable, Payroll and Purchasing have been accrued to indirect costs and not allocated to the functional areas pending the receipt of actual SLA billings and related cost drivers necessary for final cost allocation. This will not change the total OM&A but will result in some differences on the specific functional areas.
- The financial statements reflect the accrual of the 2008-2011 tax refunds resulting from KPMG's preparation of amended returns. As the Finance Department had not accrued for this recovery in the 2012 fiscal year, the recognition in 2013 will impact current and future income taxes. Since the recalculation of the 2011 amended return resulted in a larger carry back of 2011 losses for tax purposes, there may be a further positive impact to 2013 reflecting the monetization of the larger than expected loss carryback to 2011.

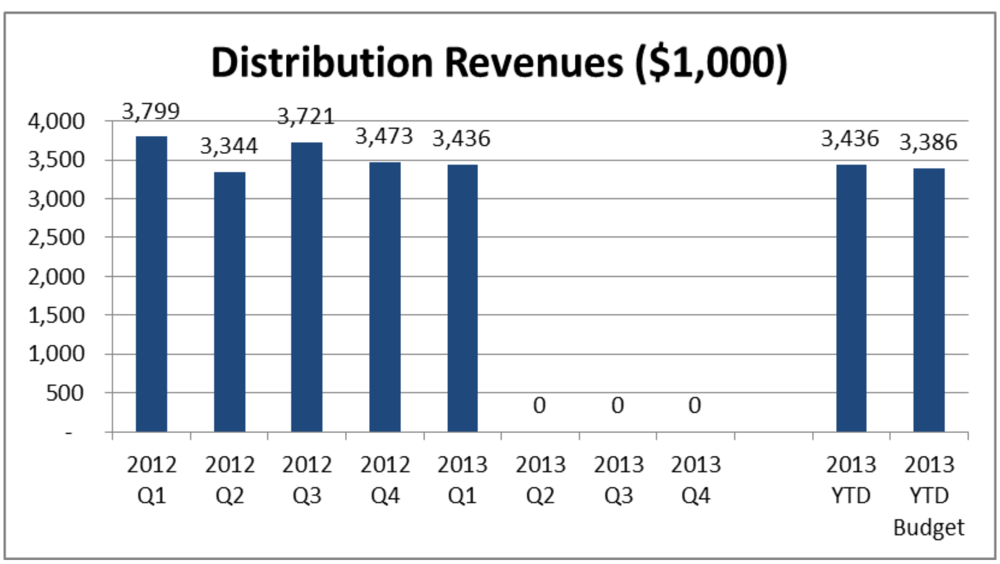
  The Finance Department has not yet completed the detailed calculations regarding this transaction consequently for the First Quarter results, the impact of the amended returns have been assumed to be break even between future and current income tax provisions. The completion of these tax calculations will be reflected in the Q2 results.

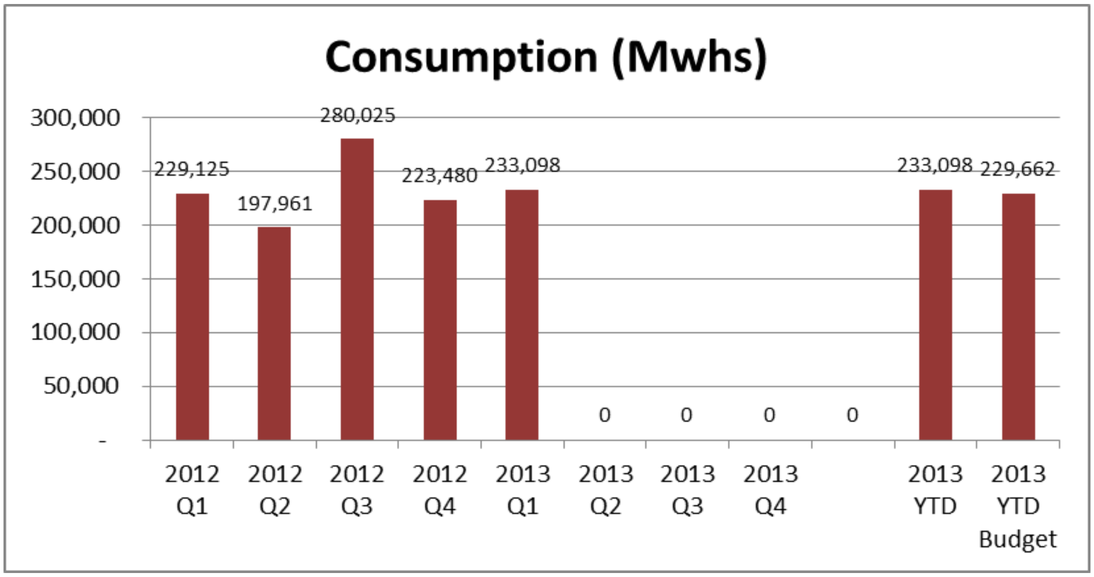
The Company reported a 2012 First Quarter Net Income of $70,000 which is $212,000 better than the First Quarter Budget target which expected an operating deficit of $142,000. This compares to the $431,000 YTD Net Income reported for the same period of 2012 keeping in mind the distribution revenue reductions due to the return of excel PILS did not begin until May 2012.



Among the highlights of this financial reporting are the following:

- The First Quarter distribution revenues reflected a $50,000 or 1.5% favorable variance to the budget plan. With a more traditional winter, the First Quarter consumption levels have slightly exceeded our budget forecast.



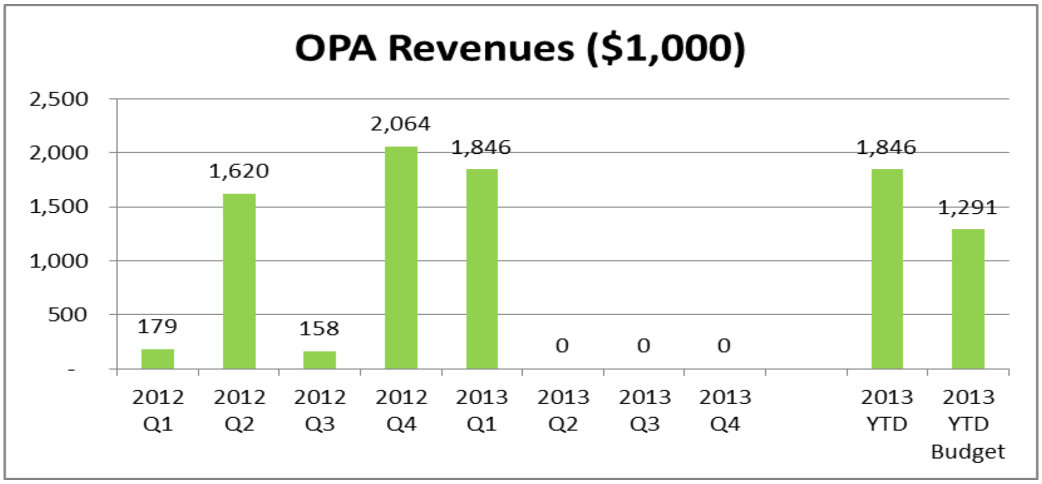


Based on the year's billed statistics tracked on Schedule H, energy consumption is up from target by 1.5%. The 2013 First Quarter consumption is 1.7% higher than the YTD consumption achieved for the same period of 2012.

Notwithstanding the positive variance on consumption, the billed demand applicable to the larger General Service Customers reflects a 778 KW YTD variance representing a 0.2% negative variance to the First Quarter budget target although it represents a 2.7% increase over the actual results for the comparable period of 2012.

Total customer counts are 38 higher than the current budget expectations and reflect an increase of 324 since the same period of 2012.

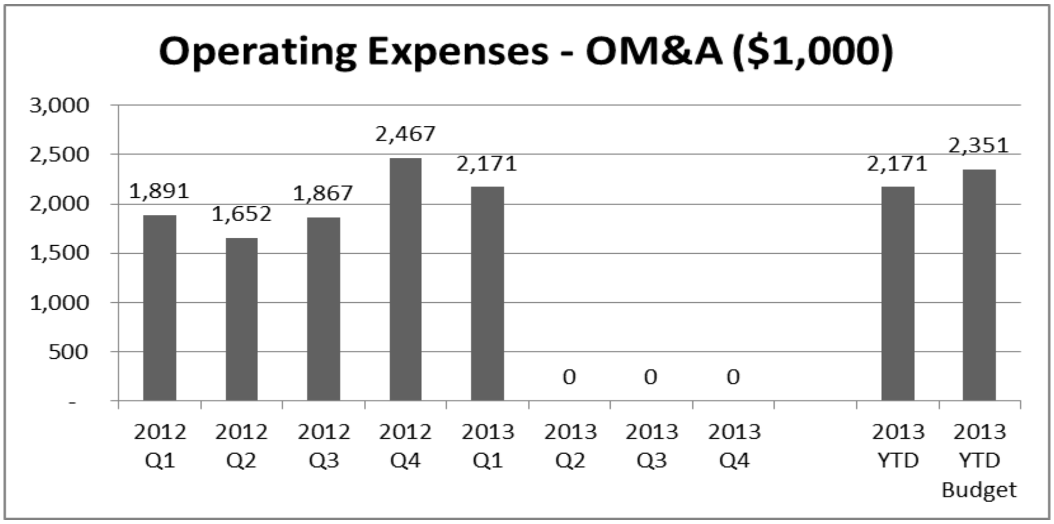
- BPI is showing a small margin of $1,400 related to some residual bonus entitlements from the ERIP program. All other OPA programs report a break-even position until the completion of the programs when an assessment of BPI entitlements can be made. The Board should take particular note of the variation in OPA funding largely dependent on the timing of advances for the major project at Ferrero.



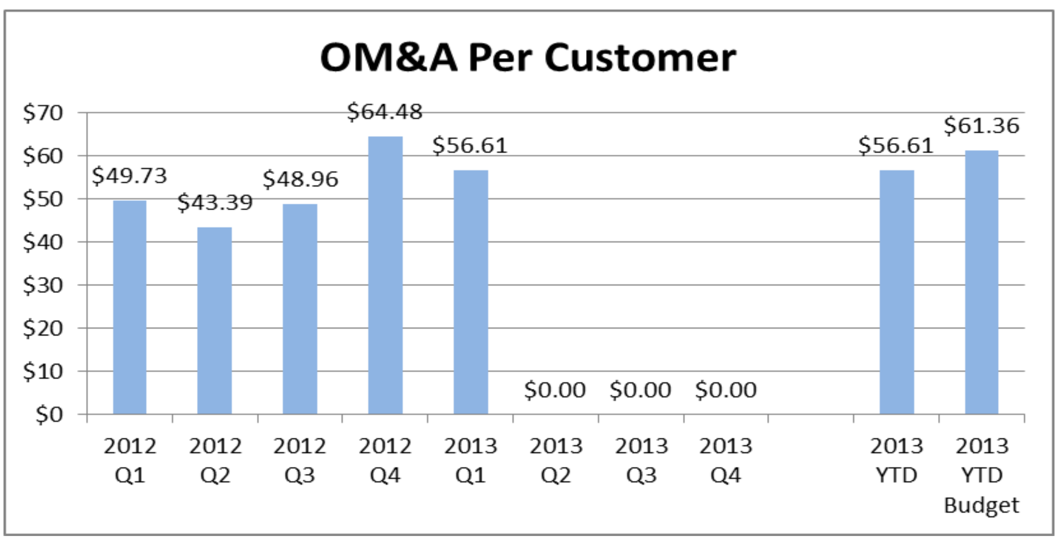
- Other revenue of $199,000 reflects an unfavorable variance of $16,000. The largest of these variances is due to YTD specific service charges reporting $22,000 less than expected. The source of other variances is provided in the details of this line item, which are itemized on Schedule F.
- Based on the statistics reported on Schedule H, the share of BPI customers served by retailers has dropped to 8.8% from the 10.7% reported at the same in terms of customer numbers, this transition represents 678 customers returning to BPI's Regulated Price Plan under its Standard Supply Service and continues the trend which began a few years ago.
- Total direct expenses (Schedule G – First page) report a $169,000 or 7.7% favorable variance primarily attributable to positive variances in Billing and Collecting of $99,000, Finance of $26,000 and yet to be incurred System Integration Study variance of $25,000. In order to provide for a test year budget covering all of 2013, the Customer Service Budget was prepared to reflect split bills on January 1, 2013. With the split anticipated for May 6, 2013, some savings are expected to accrue until the full costs of separate bills are introduced in May. It is important to keep in mind that since the City have yet to invoice BPI for applicable shared costs, this variance could change once the actual billings are recorded.

  Net Indirect costs (Schedule G – Second page) reflects an $11,000 favorable variance largely due to the treasury and accounting line. As outlined previously, these costs will be allocated to the operational areas once actual SLA charges are received from the City. The Budget assumed a portion of these indirect costs would be allocated to the direct expenses.
- Based on the First Quarter 2013 results, the total gross indirect costs allocated was $58,000 less than budgeted but because of the allocations to recoverable accounts, the impact on the operational accounts is a favorable variance of $62,000.

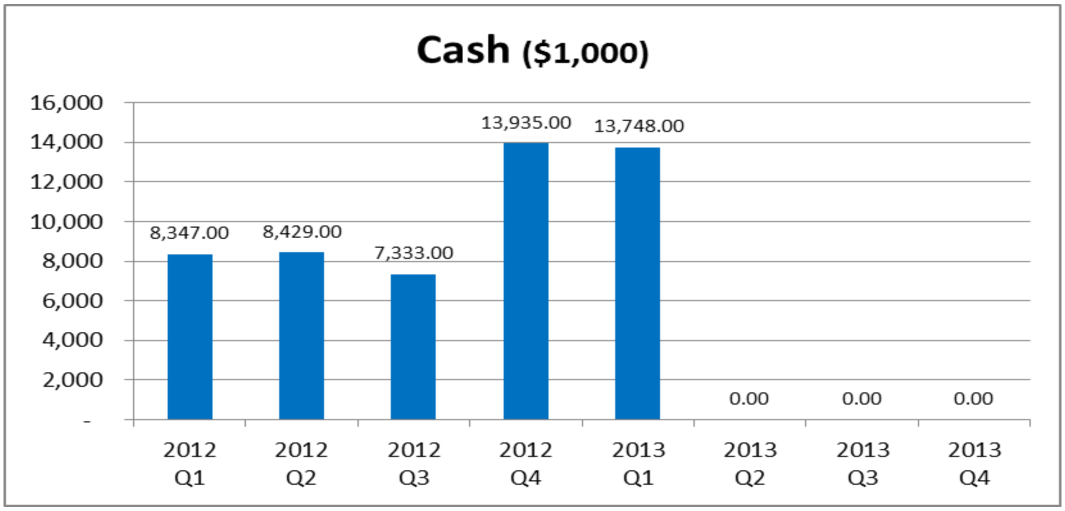
- The Board should be aware that despite retaining CGAAP for 2013 reporting, BPI did implement the OEB's direction to adopt the new capitalization policy and useful lives relating to Property Plant and Equipment which virtually aligns the accounting of PPE to those required under MIFRS. The impact on the 2013 First Quarter is the requirement to absorb in OMA all of the indirect costs which would have been previously capitalized as a component of the constructed assets. To put this into perspective, BPI capitalized in the First Quarter of 2012, $211,000. Such costs are now components of OM&A but will be offset by some $214,000 reductions in amortization from those recorded in 2012.



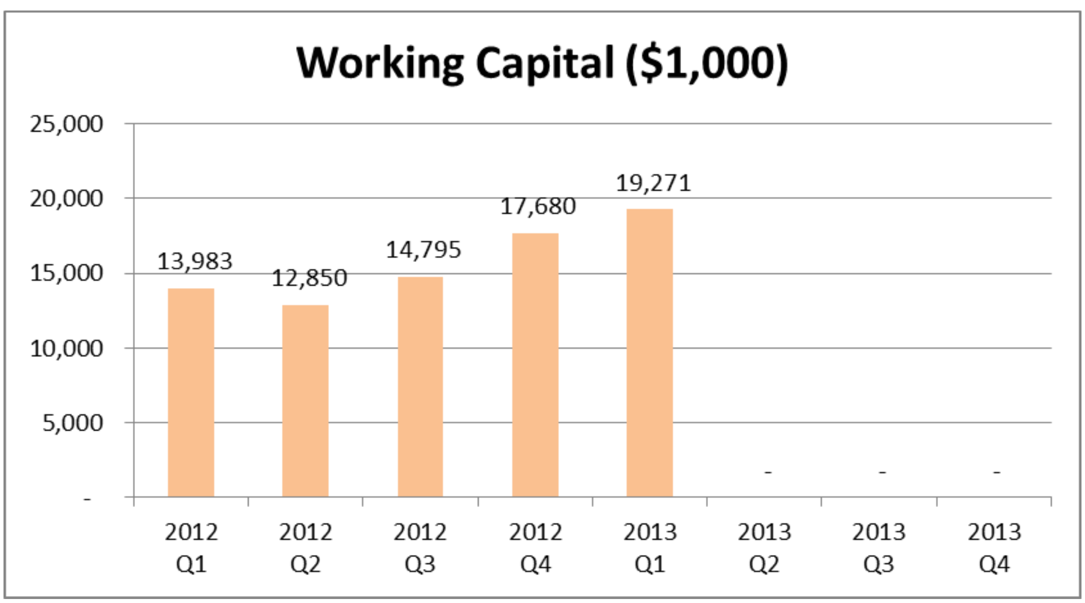
- On a per customer basis, the First Quarter OM&A reflect the following trending:



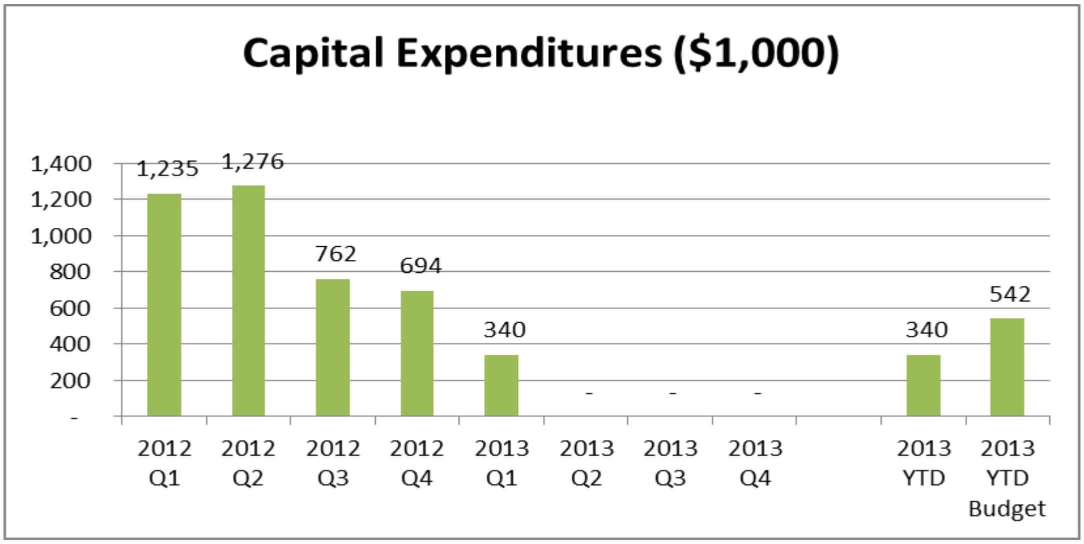
- Cash at the end of the First Quarter of $13,748,000 reflects an $187,000 reduction from the levels reported at the end of 2012. The recent trending on cash reflects the receipt of the 4.2 million in Long Term Debt proceeds during the last Quarter of 2012.



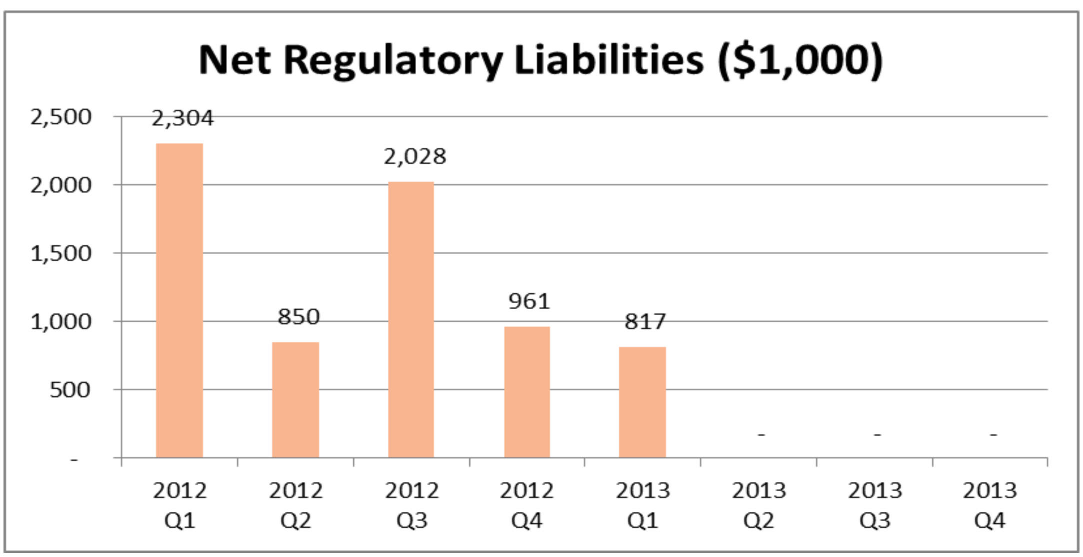
- The trending in working **c**apital levels reflect the increase in Q4 2012 related to the receipt of the $4.2 million in Long Term Debt proceeds. BPI achieved a further increase in working capital in Q1 2013 because of the accrual for the $1.3 million in confirmed tax refunds related to the filing of 2008-2011 amended returns reflecting the change in the treatment of indirect overheads for tax purposes. This increase in working capital was offset by an equivalent reduction in future income tax assets.



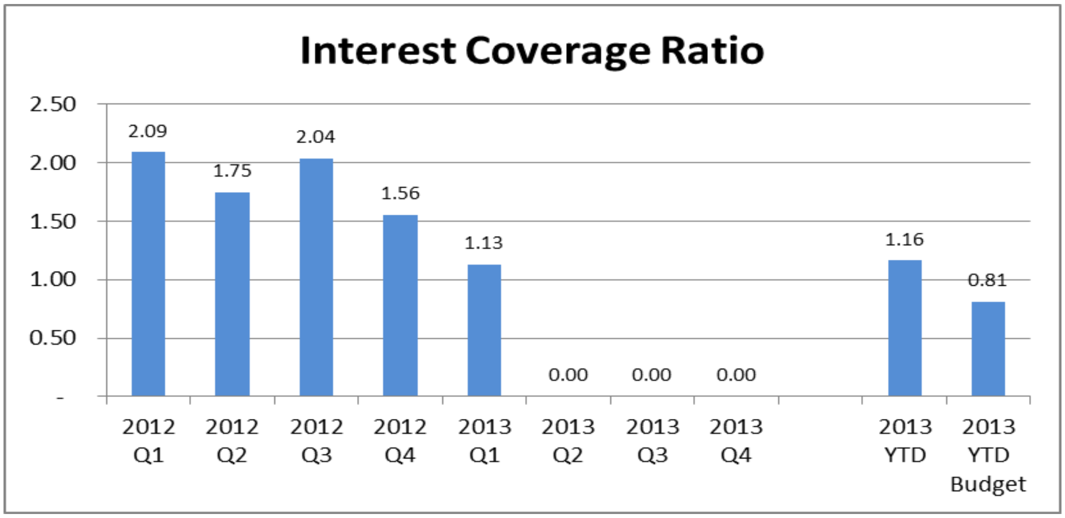
- The Schedule of Capital Expenditures (Schedule D) reflects the First Quarter progress on the 2013 capital program totaling $340,000. This represents a $203,000 favourable positive variance keeping in mind the capital budget is weighted on a straight line basis. The large expenditure in 2012 was unusual as the First Quarter results reflected the start of the Power Line Road project and the payment for development capital contributions totaling $379,000.

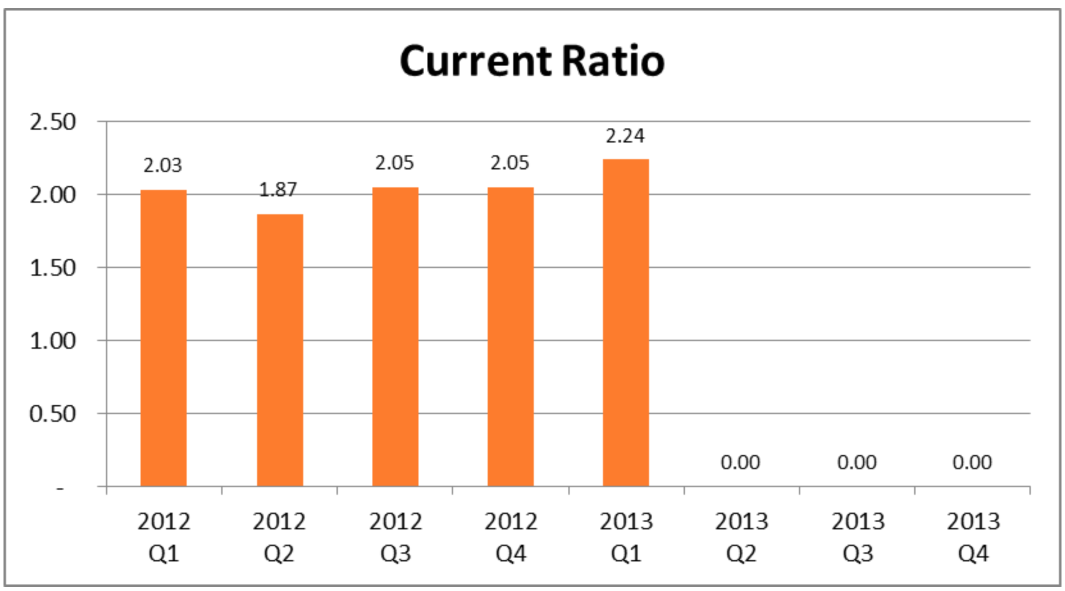


- Schedule E Schedule of Regulatory Assets and Liabilities reflect that BPI is reporting a net liability position of $817,000 a slight reduction to the $961,000 reported at the end of 2012. This reflects 64.5% reduction in this position from the $2.3 million liability position reflected at the same time in 2011.



- With respect to liquidity, as margins continue to tighten, its interest coverage ratio continues to deteriorate. Nevertheless, this is not expected to be an issue for 2013 given the Company's strong cash and working capital positions as reflected in the current ratio trend.





9.0 FINANCIAL IMPLICATIONS

The completion of the First Quarter results reflects a positive financial performance resulting from favorable variances in distribution revenues and operating costs. Unfortunately, one quarter does not necessarily predict the outcome for the fiscal year. Nevertheless, these early positive results are encouraging.

Management will continue to monitor the Company's performance to ensure BPI can meet or exceed the targeted financial performance for 2013.

10.0 CONCLUSION

The Company's First Quarter results reflect a positive YTD performance. With reported revenues significantly impacted by weather patterns, positive quarters can be offset by future negative performance in later quarters. Nevertheless, the First Quarter results reflect a positive start to the year.

Signed by:	**Signed by:**
Brian D'Amboise, CFO	Paul Kwasnik, President & CEO

ATTACHMENTS:

A – First Quarter 2013 Interim Financial Statements – CGAAP

DATE: September 26, 2013 **REPORT NO. BPI-1309-006**

TO: Chair and Directors

FROM: Brian D'Amboise, Chief Financial Officer

1.0 TYPE OF REPORT:

☐ **For Decision**

☐ **For Discussion**

☒ **For Information**

2.0 TOPIC: INTERIM FINANCIAL STATEMENTS – SECOND QUARTER 2013

3.0 RECOMMENDATION

Not Applicable

4.0 PURPOSE

To provide highlights of the current Quarter's financial position and results of operations.

5.0 BACKGROUND

The quarterly interim financial statements of Brantford Power Inc. are presented with a covering report summarizing the current reporting highlights and to raise to the attention of the Board any additional related matters.

As a result of the decision made to file the 2013 Cost of Service Distribution Rate Application under Canadian Generally Accepted Accounting Principles (CGAAP), Management is reporting the 2013 operating results using CGAAP. As the budget was prepared using Modified International Financial Reporting Standards (MIFRS), the presentation of the budget has been updated to reflect CGAAP treatment without any changes to the underlying transactions contained in the MIFRS based approved budget.

6.0 INPUT FROM OTHER SOURCES

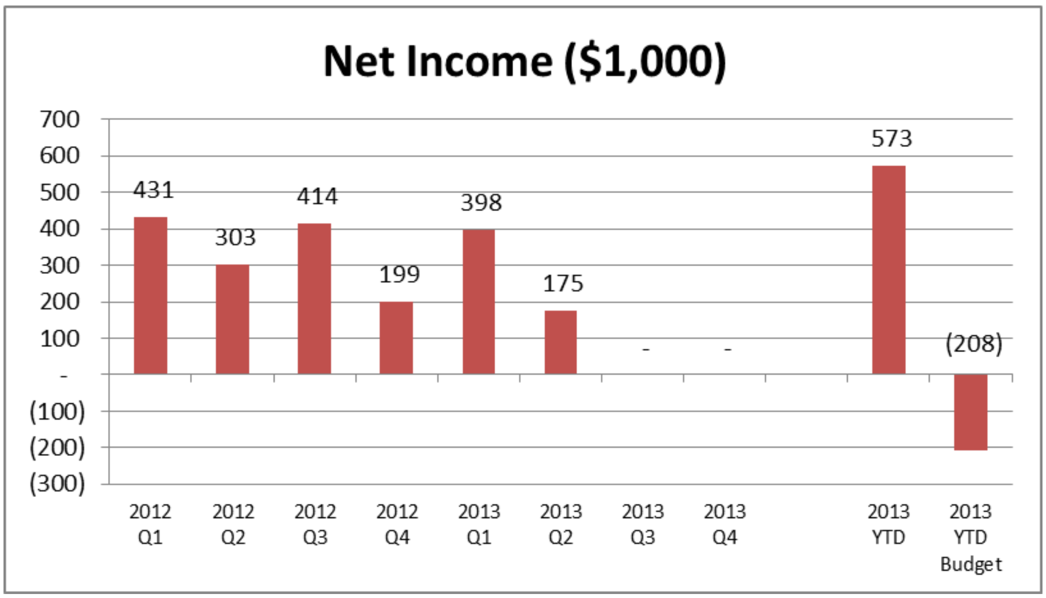
Not Applicable

7.0 STRATEGIC PLANNING CONTEXT

Not Applicable

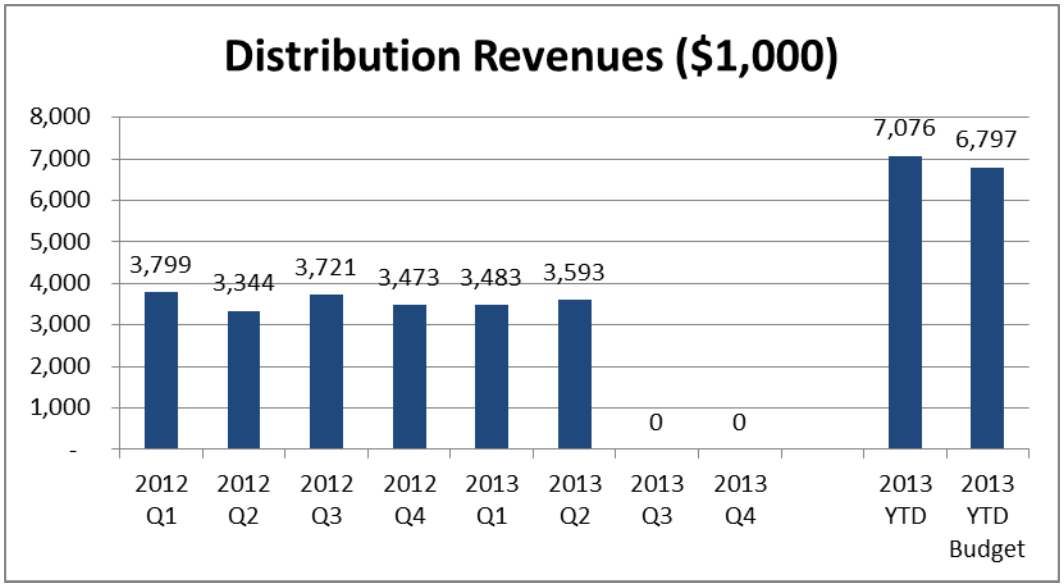
8.0 ANALYSIS

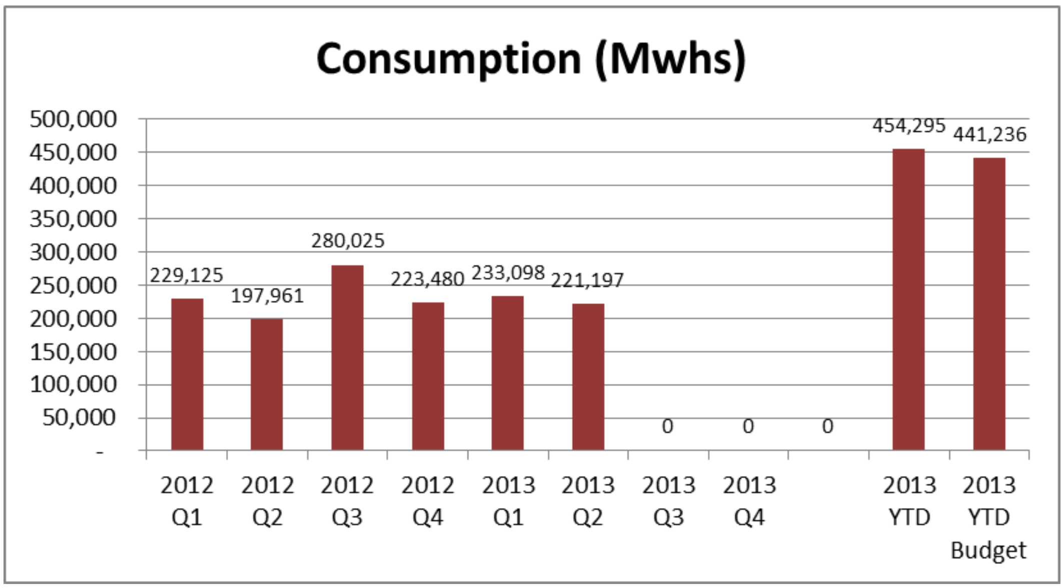
The Company reported a 2013 2nd Quarter Net Income of $573,000 which is $781,000 better than the 2nd Quarter Budget target which expected an operating deficit of $208,000. This compares to the $734,000 YTD Net Income reported for the same period of 2012 keeping in mind the distribution revenue reductions due to the return of excel PILS did not begin until May 2012.



Among the highlights of this financial reporting are the following:

- The 2nd Quarter distribution revenues reflected a $278,000 or 4.1% favorable variance to the budget plan. With a more traditional winter, and the beginning of hot weather towards the end of the 2nd Quarter, consumption levels have exceeded our budget forecast.



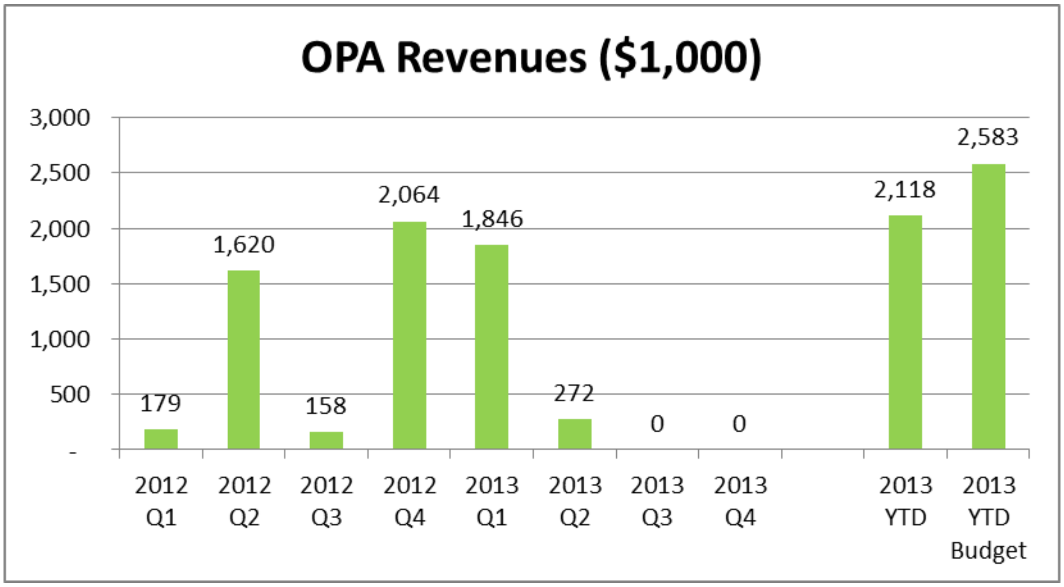


Based on the year's billed statistics tracked on Schedule H, energy consumption is up from target by 3.0%. The 2013 2nd Quarter consumption is 5.8% or 24,821 Mwh higher than the YTD consumption achieved for the same period of 2012.

Similarly, the billed demand applicable to the larger General Service Customers reflects a 16,461 KW representing a 2.2% positive variance reversing the negative variance reported at the end of the 1st Quarter. This level of Demand represents 12,833 more or 1.7% increase over the actual results for the comparable period of 2012.

Total customer counts are 36 higher than the current budget expectations and reflect an increase of 329 since the same period of 2012.

- BPI is showing a small margin of $1,187 related to some residual bonus entitlements from the ERIP program. All other OPA programs report a break-even position until the completion of the programs when an assessment of BPI entitlements can be made. The Board should take particular note of the variation in OPA funding largely dependent on the timing of advances for the major project at Ferrero.



- Other revenue of $475,000 reflects a favorable variance of $43,000. The largest of these variances amounting to $38,000 is related to a positive variance on interest income. The source of other minor variances is provided in the details of this line item, which are itemized on Schedule F.

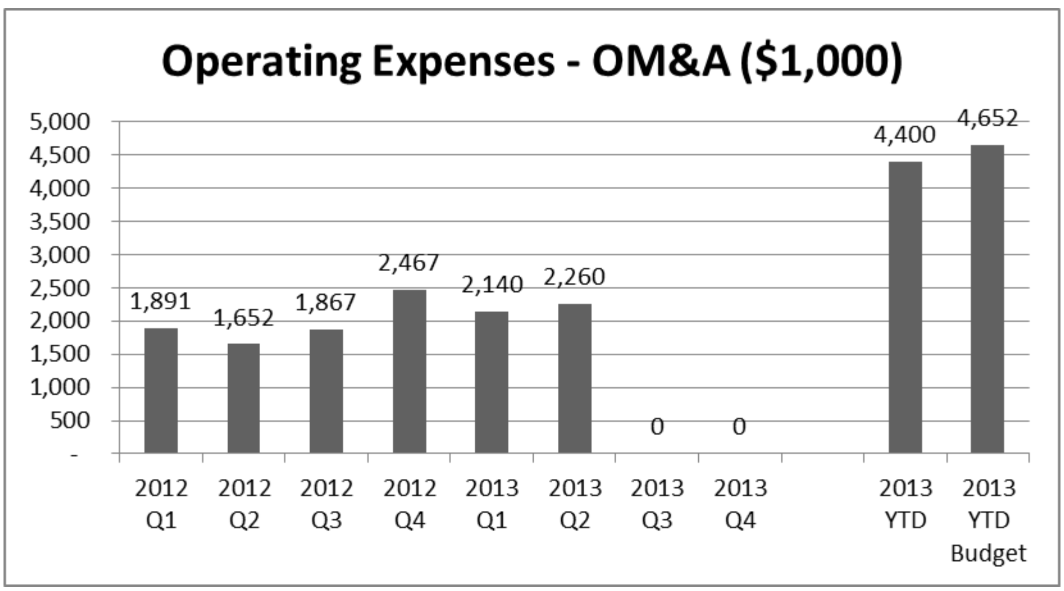
- Based on the statistics reported on Schedule H, the share of BPI customers served by retailers continues the trend of reducing market share representing at the end of June, only 8.5% share of our customer base. This compares to the 9.8% reported at the same time in 2012 representing a further 472 customers returning to BPI's Regulated Price Plan under its Standard Supply Service since that time.

- Total direct expenses (Schedule G – First page) report an $181,000 or 4.1% favorable variance primarily attributable to positive variances in Billing and Collecting of $212,000 offset by unfavourable variances in General Administration of $35,000.

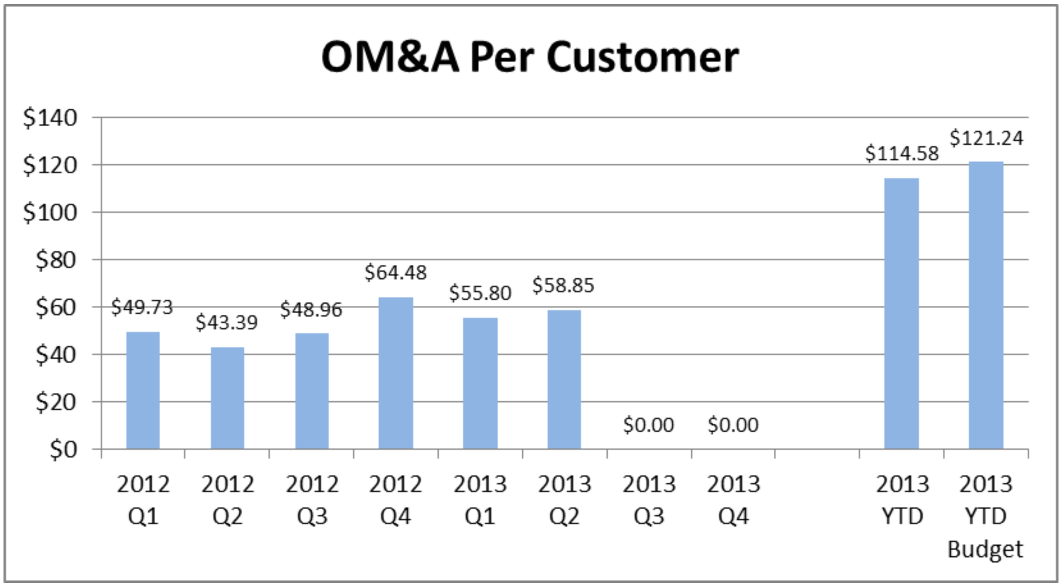
  In order to provide for a test year budget covering all of 2013, the Customer Service Budget was prepared to reflect split bills on January 1, 2013. With the split implementation actually taking place on May 6, 2013, some savings have been achieved as the additional budgeted costs for separate bills did not begin until May.

Net Indirect costs (Schedule G – Second page) reflects a $71,000 favorable variance largely due to the treasury and accounting line. As treasury and accounting charges under the Service Level Agreement is allocated to the operating accounts, the budget provision here was overstated as it reflected the gross costs before allocation. Consequently, there will be no actuals reported against this budget in 2013.

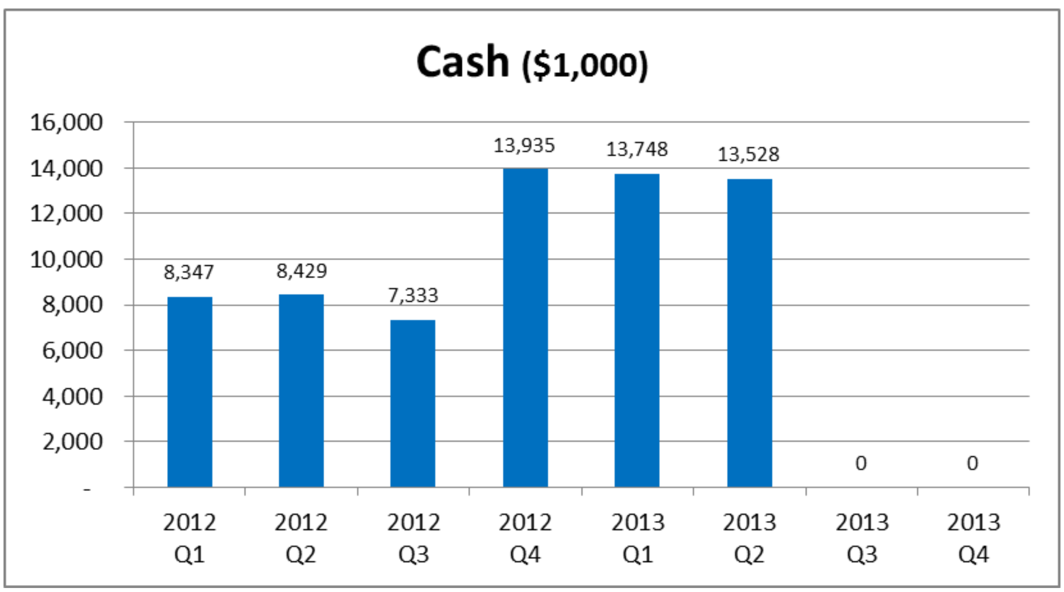
- Based on the 2nd Quarter 2013 results, the total gross indirect costs allocated was $144,000 less than budgeted but because of the allocations to recoverable accounts, the impact on the operational accounts is a favorable variance of $150,000.
- The Board should be aware that despite retaining CGAAP for 2013 reporting, BPI did implement the OEB's direction to adopt the new capitalization policy and useful lives relating to Property Plant and Equipment which virtually aligns the accounting of PPE to those required under MIFRS. The impact on the 2013 2nd Quarter is the requirement to absorb in OMA all of the indirect costs which would have been previously capitalized as a component of the constructed assets. To put this into perspective, BPI capitalized to the end of the 2nd Quarter of 2012, $604,000. Such costs are now components of OM&A but will be offset by $457,000 reductions in amortization costs when compared to those recorded in 2012.



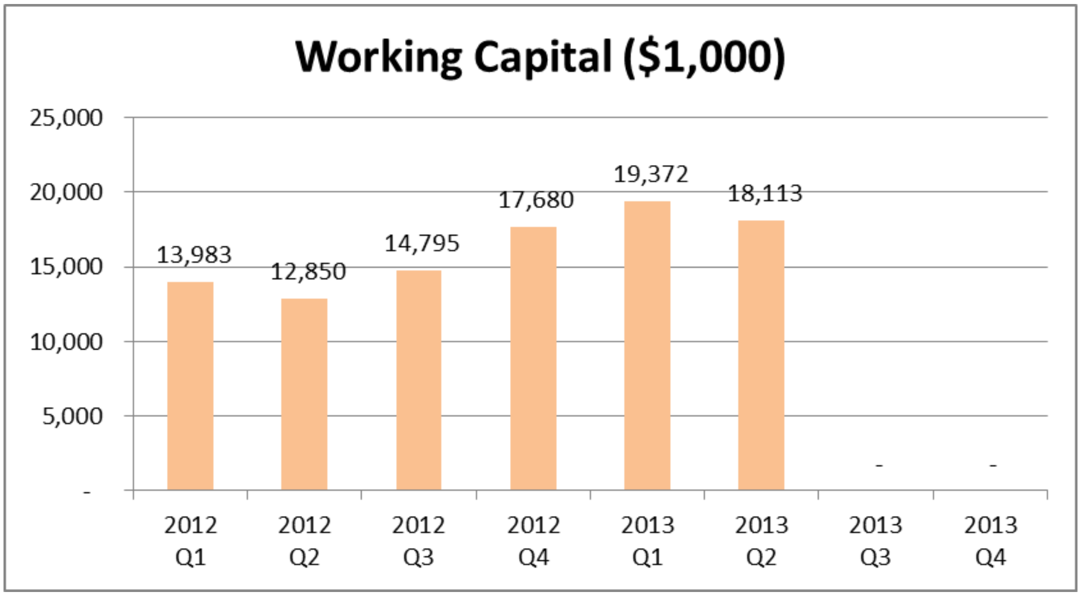
- On a per customer basis, the 2nd Quarter OM&A reflect the following trending:



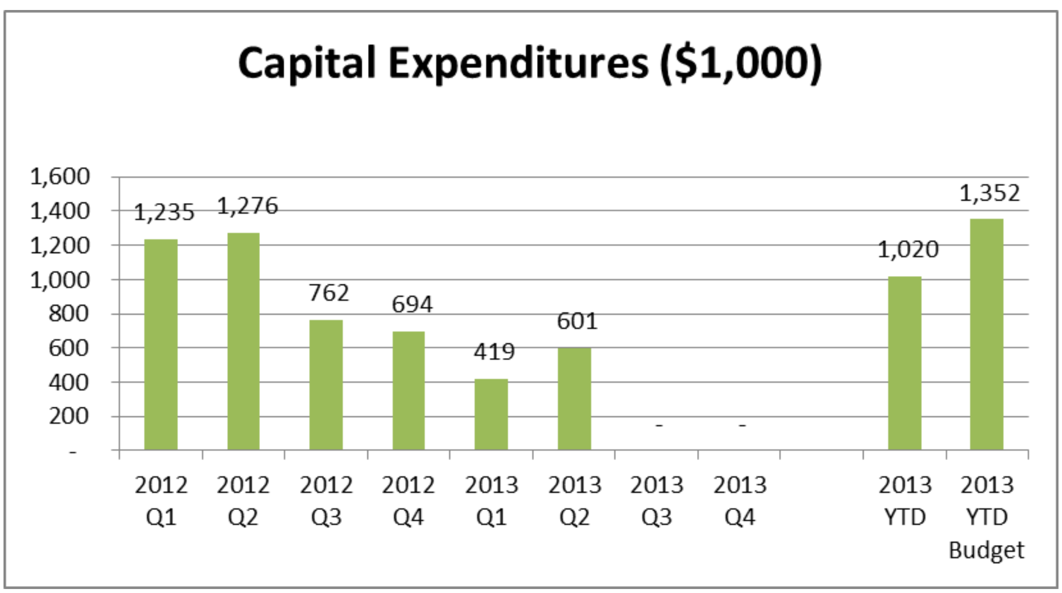
- Cash at the end of the 2nd Quarter of $13,528,000 reflects a $407,000 reduction from the levels reported at the end of 2012. The recent trending on cash reflects the receipt of the 4.2 million in Long Term Debt proceeds during the last Quarter of 2012.



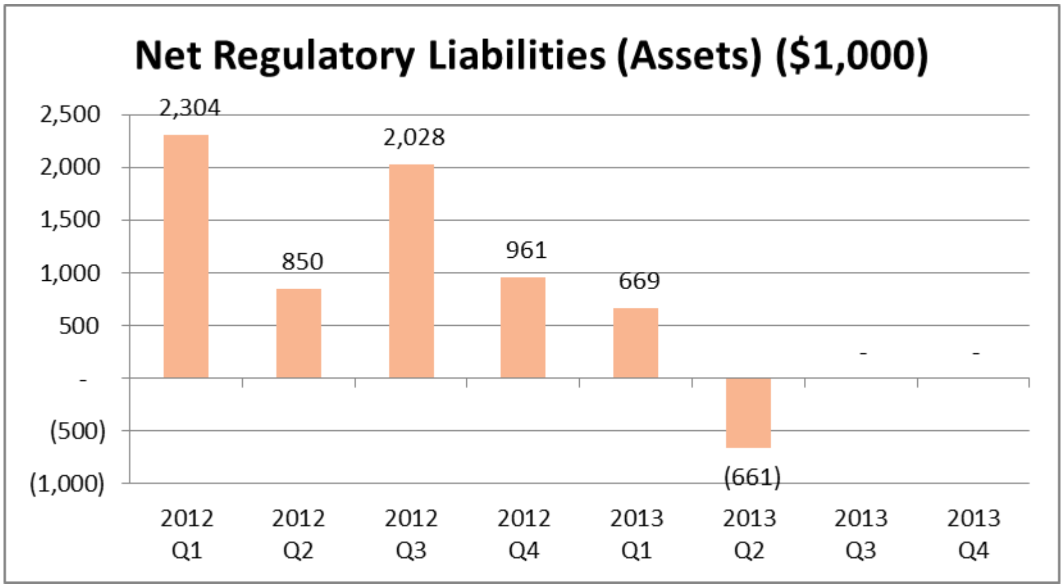
- The trending in working **c**apital levels reflect the increase in Q4 2012 related to the receipt of the $4.2 million in Long Term Debt proceeds. BPI achieved a further increase in working capital in Q1 2013 because of the recognition for the $1.3 million in confirmed tax refunds related to the filing of 2008-2011 amended returns reflecting the change in the treatment of indirect overheads for tax purposes.



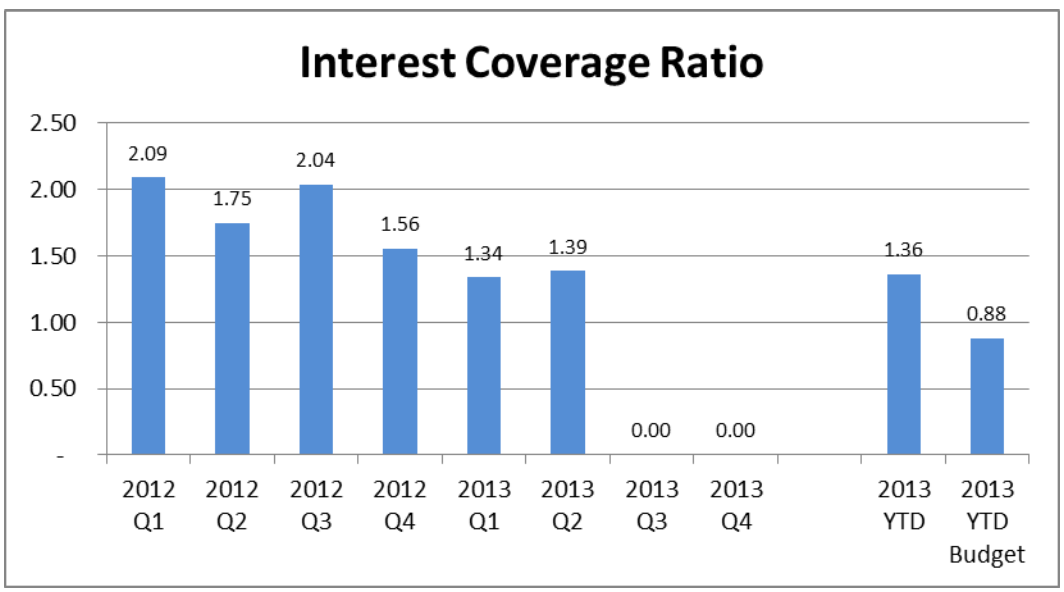
- The Schedule of Capital Expenditures (Schedule D) reflects the 2nd Quarter progress on the 2013 capital program totaling $1,020,000. This represents a $162,000 favourable positive variance keeping in mind the capital budget is weighted on a straight line basis. The comparatively large YTD capital expenditure in 2012 is due to the 2012 results which reflected the start of the Power Line Road project and the payment for development capital contributions totaling $379,000 plus the capitalization of indirect overhead charges in 2012 no longer recognized in 2013.

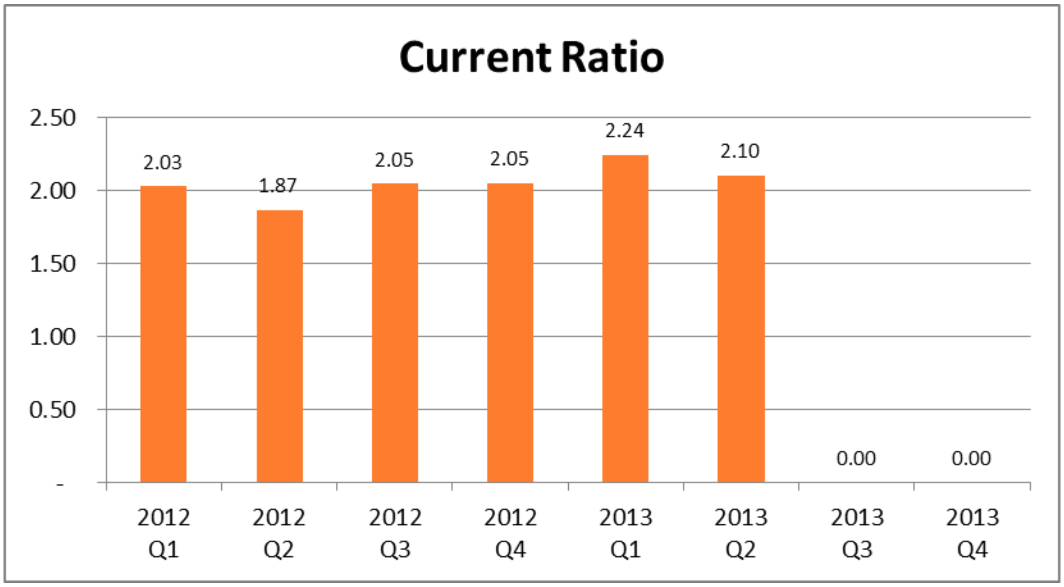


- Schedule E Schedule of Regulatory Assets and Liabilities reflect that BPI is reporting for the first time in a number of quarters a net regulatory asset position a change to the $961,000 regulatory liability reported at the end of 2012. This is largely due to the continued reduction in regulatory liabilities being liquidated via approved rate riders and the increasing regulatory asset values attributable to the increasing rates for the global adjustment.



- With respect to liquidity, as margins continue to tighten, BPI interest coverage ratio continues to deteriorate. Nevertheless, this is not expected to be an issue for 2013 given the Company's strong cash and working capital positions as reflected in the current ratio trend.





9.0 FINANCIAL IMPLICATIONS

The completion of the 2nd Quarter results reflects a positive financial performance attributable to favorable variances in distribution revenues and operating costs. Unfortunately, with the small targeted Net Income performance for 2013, the year-end performance will be very sensitive to fluctuating revenues attributable to weather patterns.

Although there was a period of high temperature during the third quarter, most of the third quarter to date reflected a more moderate temperature than in typical summer periods. Nevertheless, these early positive results are encouraging and do provide some contingency room should subsequent quarters not achieve the targeted returns due to variances in distribution revenues.

Management will continue to monitor the Company's performance to ensure BPI can meet or exceed the targeted financial performance for 2013.

10.0 CONCLUSION

The Company's 2nd Quarter results continue to reflect a positive YTD performance. With reported revenues significantly impacted by weather patterns, positive quarters can be offset by future negative performance in later quarters. Nevertheless, the first half of the year represents positive performance against plan maintaining a relatively strong financial position.

Signed by: **Signed by:**

Brian D'Amboise, CFO

Paul Kwasnik, President & CEO

ATTACHMENTS:

A – 2nd Quarter 2013 Interim Financial Statements – CGAAP

ATTACHMENT C

REFERENCE: 1.0 Energy Probe-5

BRANTFORD power
Your delivery company

April 16, 2013

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

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli,

RE: Reporting and record keeping requirements (RRR) section 2.1.6
Brantford Power Inc. 2012 Audited Financial Statements

Please find enclosed 2 copies of Brantford Power Inc.'s 2012 Audited Financial Statements.

If you have any questions, please contact me at 519-751-3522 x 3243.

Sincerely,

PChisulo

Phillip Chisulo
Regulatory Analyst

Copies to: Mr. Paul Kwasnik, President & CEO, Brantford Power Inc.
Mrs. Heather Wyatt, Director of Regulatory Affairs, Board Secretary, Brantford Power Inc.

Telephone
519-751-3522
Fax
519-753-6130

Brantford Power Inc.
84 Market Street, P.O. Box 308, Brantford, Ontario N3T 5N8

Financial Statements of

Brantford Power Inc.

December 31, 2012

Brantford Power Inc.
Table of Contents
December 31, 2012

Brantford Power Inc.
Management Report
December 31, 2012

The accompanying financial statements are the responsibility of management of Brantford Power Inc. (the Company). In management's opinion, these financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Management has selected accounting principles and methods that are appropriate to the Company's circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. The notes to the financial statements and any other supplementary information presented are consistent with that in the financial statements.

The Company maintains systems of internal accounting and administrative controls that are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, that transactions are properly authorized and that the Company's assets are properly accounted for and adequately safeguarded.

The financial statements have been examined by Deloitte LLP, the external auditors of the Company. The responsibility of the external auditors is to express their opinion on whether the financial statements are fairly presented, in all material respects, in accordance with Canadian generally accepted accounting principles.

The board of directors, through the finance committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The finance committee meets periodically with management, as well with the external auditors to satisfy itself that each party is properly discharging its responsibilities with respect to internal controls and financial reporting. The finance committee also reviews the financial statements and recommends their approval to the board of directors. Deloitte LLP has full and free access to the finance committee, with and without the presence of management.

Paul Kwasnik
President and Chief Executive Officer
March 28, 2013

Brian D'Amboise, CPA, CA
Chief Financial Officer
March 28, 2013

Deloitte

Deloitte LLP
1005 Skyview Dr
Suite 200
Burlington ON L7P 5B1
Canada

Tel: 905-315-6770
Fax: 905-315-6700
www.deloitte.ca

Independent Auditor's Report

To the Board of Directors of
Brantford Power Inc.

We have audited the accompanying financial statements of Brantford Power Inc. which comprise the balance sheet as at December 31, 2012 and the statements of operations, retained earnings, comprehensive income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Brantford Power Inc. as at December 31, 2012 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Accountants
Licensed Public Accountants
March 28, 2013

Brantford Power Inc.
Balance Sheet
as at December 31, 2012

Assets	**2012**	2011
	$	**$**
Current Assets		
Cash and cash equivalents	**13,935,062**	9,200,282
Accounts receivable	**8,943,997**	7,373,814
Unbilled revenue	**8,557,480**	8,636,720
Inventories	**1,106,630**	718,936
Special deposits	**1,117,443**	1,155,522
Prepaid expenses	**97,411**	107,758
Payments in lieu of corporate income taxes	**569,406**	1,262,583
Future payments in lieu of corporate income taxes - note 22	**180,730**	178,500
	34,508,159	28,634,115
Property, plant and equipment - note 5	**59,942,622**	59,873,172
Other Assets		
Regulatory assets - note 9	**5,218,627**	4,147,328
Long-term special deposits	**742,782**	918,090
Long-term prepaid expenses	**79,030**	107,859
Future payments in lieu of corporate income taxes - note 22	**1,926,312**	2,279,696
Intangible assets - note 6	**3,562,397**	3,479,311
	11,529,148	10,932,284
	105,979,929	99,439,571

Brantford Power Inc.
Balance Sheet
as at December 31, 2012

Liabilities and Shareholder's Equity	2012	2011
	$	$
Current Liabilities		
Accounts payable and accrued liabilities	**12,074,178**	9,299,107
Accounts payable to the City of Brantford - note 8	**896,904**	1,489,970
Interest payable to the City of Brantford - note 10	**1,419,904**	1,427,564
Due to affiliates - note 8	**328,444**	332,663
Current portion of customer deposits	**1,117,443**	1,155,522
Current portion of long-term debt - note 10	**991,134**	598,986
Current portion of vested sick leave - note 11	**145,885**	-
	16,973,892	14,303,812
Long-term debt - note 10	**44,179,375**	40,919,451
Other Liabilities		
Regulatory liabilities - note 9	**6,180,082**	7,329,824
Long-term customer deposits	**742,782**	918,090
Employee future benefits - note 12	**2,119,216**	898,067
Accumulated vested sick leave credits - note 11	**88,093**	78,512
Derivative liabilities - note 21	**554,860**	713,683
	9,685,033	9,938,176
Contingencies and Commitments - note 13		
Shareholder's Equity		
Share capital - note 14	**22,437,505**	22,437,505
Retained Earnings	**12,955,971**	12,358,906
Contributed surplus - note 7	**141,319**	-
Accumulated Other Comprehensive Loss - note 15	**(393,166)**	(518,279)
	35,141,629	34,278,132
	105,979,929	99,439,571

Signed on behalf of the Board:

Director

Director

See accompanying notes

Brantford Power Inc.
Statement of Retained Earnings
for the year ended December 31, 2012

	2012	2011
	$	$
Retained Earnings, Beginning of Year	**12,358,906**	11,519,294
Net Income	**1,347,065**	2,289,612
Dividends	**(750,000)**	(1,450,000)
Retained Earnings, End of Year	**12,955,971**	12,358,906

Brantford Power Inc.
Statement of Operations
for the year ended December 31, 2012

	2012 $	2011 $
Revenue		
Electricity distribution service charges - note 17	**14,336,994**	15,158,434
Ontario Power Authority conservation programs	**4,020,508**	723,014
Specific service charges	**407,628**	469,500
Interest income	**273,775**	278,195
Other income	**297,897**	332,439
	19,336,802	16,961,582
Expenses		
Distribution operations and maintenance	**3,389,490**	2,954,060
Billing and collecting	**1,870,898**	1,941,884
General administration	**2,616,711**	2,095,391
Ontario Power Authority conservation programs	**3,683,840**	735,093
Interest on long-term debt	**2,163,585**	2,159,034
Other financing expenses	**172,775**	175,492
Capital tax	**-**	(1,318)
Amortization - note 19	**3,595,408**	3,842,300
	17,492,707	13,901,936
Income before payments in lieu of corporate income taxes	**1,844,095**	3,059,646
Payments in lieu of corporate income taxes - note 22	**497,030**	770,034
Net income	**1,347,065**	2,289,612

See accompanying notes

Brantford Power Inc.
Statement of Comprehensive Income
for the year ended December 31, 2012

	2012 $	2011 $
Net Income	**1,347,065**	2,289,612
Other comprehensive loss		
Unrealized gain (loss) on derivative instruments designated as cash flow hedges - Note 21	**156,203**	(191,491)
Future (payment) recovery in lieu of corporate income taxes	**(31,090)**	47,870
	125,113	(143,621)
Comprehensive Income	**1,472,178**	2,145,991

Brantford Power Inc.
Statement of Cash Flows
for the year ended December 31, 2012

	2012 $	2011 $
Operating activities		
Net income	**1,347,065**	2,289,612
Items not affecting cash		
Amortization - note 19	**3,813,949**	4,113,716
Future payments in lieu of corporate income taxes	**316,790**	1,028,630
Gain on disposal of property, plant and equipment	**(565)**	(19,025)
Other items not affecting cash	**1,579,990**	46,873
	7,057,229	7,459,806
Changes in non-cash working capital components - note 18	**995,013**	(599,971)
	8,052,242	6,859,835
Investing activities		
Acquisition of property, plant and equipment	**(4,572,036)**	(4,877,142)
(Increase) decrease in regulatory assets	**(1,071,299)**	899,233
Decrease in regulatory liabilities	**(1,149,742)**	(3,679,967)
Decrease in special deposits	**213,387**	434,908
Proceeds from disposal of property, plant and equipment	**565**	19,025
	(6,579,125)	(7,203,943)
Financing activities		
Proceeds of issuance of long-term debt	**4,230,000**	550,000
Capital contributions received	**605,551**	265,560
Repayment of long-term debt	**(610,501)**	(567,012)
Decrease in customer deposits	**(213,387)**	(434,908)
Dividends paid	**(750,000)**	(1,450,000)
	3,261,663	(1,636,360)
Increase (decrease) in cash and cash equivalents	**4,734,780**	(1,980,468)
Cash and cash equivalents, beginning of year	**9,200,282**	11,180,750
Cash and cash equivalents, end of year	**13,935,062**	9,200,282
Supplemental Disclosure of Cash Flows		
Interest received	**153,355**	158,760
Interest paid	**2,121,090**	2,202,707
Payment for income taxes	**512,940**	1,025,877

1. Incorporation

On March 1, 2000, Brantford Power Inc. (the Company) was incorporated under the Business Corporations Act (Ontario) along with its affiliate companies, Brantford Hydro Inc. and Brantford Energy Corporation. Another affiliated company, Brantford Generation Inc., was incorporated in 2007. The incorporations were pursuant to the provisions of the Energy Competition Act, 1998. The Company is a wholly-owned subsidiary of Brantford Energy Corporation. The Company provides electricity distribution services to residents of the City of Brantford. The operations of the company are regulated by the Ontario Energy Board (OEB).

2. Accounting Policies

Basis of accounting

The financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and policies as set forth in the Accounting Procedures Manual issued by the OEB under the authority of the Ontario Energy Board Act, 1998. Significant accounting policies are summarized below:

Regulation

The Company is regulated by the OEB and requires OEB approval for any distribution service rate adjustments. The following accounting policies applicable to rate regulated operations differ from GAAP for companies operating in an unregulated environment:

Regulatory assets and liabilities

Regulatory assets primarily represent costs that have been deferred because they are expected to be recovered in future rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding wholesale market cost of power incurred by the utility.

Regulatory assets and liabilities will be recognized for rate-setting and financial statement purposes only to the extent allowed by the regulator. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in the results of operations in the period that the assessment is made. Asset and liability balances and current year activities are detailed in Note 9.

2. Accounting Policies - continued

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions towards the cost of constructing company assets. Capital contributions for the year of $605,551 (2011 - $265,560) have been recorded as an offset to capital assets. Amortization of contributed capital is recorded at an equivalent rate to that used for amortization of the related assets.

Allowance for use of funds during construction

The company capitalizes an allowance for use of funds during construction representing the cost of funds during the construction period. The rate used is prescribed by the OEB and updated on a quarterly basis. The total allowance for use of funds during construction capitalized for the year amounted to $27,434 (2011 - $56,469).

Stranded meters

As a result of the OEB's smart meter initiative, the Company has removed conventional meters and replaced them with smart meters. The net book value of the conventional meters removed from service prior to the end of their useful life has been classified as stranded meters and reallocated from property, plant and equipment to intangible assets. The OEB will allow the Company to recover the costs of these stranded meters through a future rate application process.

Payment in lieu of income taxes

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes (PILS) to the Ontario Electricity Financial Corporation (OEFC), beginning on October 1, 2001. These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations.

The Company uses the asset and liability method of accounting for payments in lieu of corporate income taxes. Accordingly, future tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax rates. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. In addition, the effect of future tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the enactment or substantive enactment date.

2. Accounting Policies - continued

Use of estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure and contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the year. During the years presented, management has made a number of estimates and valuation assumptions including allowance for doubtful accounts receivable, unbilled revenue, useful lives, certain accruals, valuation of financial instruments including derivatives and future income tax liabilities. Estimates are based on historical experience, current trends and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Minister of Energy.

Cash and cash equivalents

Cash and cash equivalents include cash and short-term investments with maturities of three months or less from the date of acquisition.

Inventories

Inventories consist of repair parts, supplies and materials and are valued at the lower of cost or net realizable value determined using a weighted average method. The Company classifies major construction related components of its electricity distribution system to property, plant and equipment.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter reading during the year to the balance sheet date.

2. Accounting Policies - continued

Property, plant and equipment

Property, plant and equipment are stated at cost and removed from the accounts when disposed or retired. Costs of assets which are pooled are removed from the accounts at the end of their estimated average service lives. Gains or losses at retirement or disposition of such assets are credited or charged to other income. Amortization is calculated on a straight-line basis over the estimated useful service life as follows.

Buildings	50 years
Transformer station	40 years
Distribution stations	30 years
Distribution lines - overhead	25 years
Distribution lines - underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Vehicles	5-8 years
Office furniture	10 years
Computer hardware	4 years
Tools and other equipment	5-10 years
Capital contribution	25 years

Other electric plant and work in progress are amortized when put in service.

Intangible assets

Intangible assets are recorded at cost and amortized over their estimated useful lives on a straight-line basis. Stranded meters represent distribution meters that have been replaced with smart meters and reallocated from property, plant and equipment. The OEB has allowed these retired meters to remain in rate base for rate making purposes. Amortization is calculated on a straight-line basis over the estimated useful service life as follows.

Land rights	50 years
Stranded meters	25 years
Software	5 years

2. Accounting Policies - continued

Long-term prepaid expenses and special deposits

Long-term prepaid expenses consist of service fees paid providing the Company with the right to use non-owned specified tangible assets for future periods. These charges are amortized on a straight-line basis over 10 years representing the expected benefit period.

Amounts are recorded as special deposits when cash is collected related to customer deposits and are expected to be held for a period exceeding one year.

Revenue recognition

Distribution revenue is recorded as revenue in the period to which it relates. Distribution revenue includes an estimated accrual for the variable component of the distribution rate based on the electricity delivered but not yet billed to customers from the last meter reading date to the year end.

Other revenue is recognized as services are rendered or contract milestones are achieved.

Impairment of long-lived assets

The Company reviews the valuation of long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. There was no impact on the financial statements as a result of asset impairments for the years ended December 31, 2012 and 2011.

Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of electricity bills as prescribed by the OEB's Retail Settlement Code. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability.

Employee future benefits

The Company provides post-retirement medical and life insurance benefits to eligible employees. The cost of post-retirement medical and life insurance benefits is expensed using the projected benefit cost method prorated on services.

The Company has adopted the corridor method of accounting for the actuarially determined gains and losses. Cumulative gains and losses in excess of 10% of the beginning accrued benefit obligation are amortized into expense on a straight-line basis over the expected remaining lifetime of the inactive members receiving benefits under the plan (15 years).

2. Accounting Policies - continued

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years, the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. Any adjustment to the liability of its fair value as a result of the passage of time is charged to earnings.

Comprehensive Income

CICA Handbook Section 1530 requires the presentation of comprehensive income and its components in a financial statement. Comprehensive income is composed of the Company's net income and other comprehensive income (OCI), which includes unrealized gains and losses on changes in the fair value of the effective portion of cash flow hedging instruments. The Company discloses comprehensive income in the financial statement "Statement of Comprehensive Income". The cumulative changes in OCI are included in Accumulated other comprehensive income net of tax (AOCI), which is presented as a category of Shareholder's equity on the Company's Balance Sheet.

Financial Instruments

The Corporation designates its financial instruments in one of the following five categories: (i) held for trading (HFT); (ii) available for sale (AFS); (iii) held to maturity (HTM); (iv) loans and receivables (LR); or (v) other liabilities (OL). All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value, with any change in fair value recognized in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

The Company has elected to add transaction costs related to financial instruments classified as other than HFT to the carrying amount of the financial instrument.

The Company has elected to use settlement-date accounting for regular-way purchases and sales of financial assets.

3. Future Changes in Accounting Framework

Changes in accounting policies

In July 2012, the OEB issued a letter to LDC's that provides direction on permitted accounting policies for depreciation expense and capitalization beginning in 2013. In this letter, the OEB states that it will require all LDC's to adopt IFRS-compliant depreciation and capitalization accounting policies effective January 1, 2013, regardless of whether the LDC has chosen to defer the adoption of IFRS as permitted by the AcSB. The OEB also approved the use of a new variance account to capture the financial differences arising as a result of adopting IFRS-compliant accounting policies in 2013. This variance account is to be disposed of as part of the LDC's next rate rebasing. Therefore, there will be no impact to net income as a result of these accounting policy changes.

As such, the Company will adopt IFRS-compliant accounting policies for depreciation and capitalization effective January 1, 2013. These policies will be selected in accordance with International Accounting Standard 16, "Property, Plant and Equipment" ("IAS 16"). IAS 16 provides more definitive guidance with respect to cost capitalization and componentization for depreciation purposes than that currently followed under Canadian GAAP.

Due to the absence of rate-regulated accounting guidance within Canadian GAAP, the Company follows regulatory accounting guidance found under US GAAP. In accordance with US GAAP Accounting Standards Codification Section 980, "Regulated Operations," the Company will adopt these changes prospectively with no retrospective restatement of prior periods.

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP effective January 1, 2011. Subsequently, the AcSB issued several optional deferrals in adoption of IFRS for rate-regulated entities. The Company qualifies for these deferrals and has elected to defer adoption for fiscal 2012 and will determine each year whether future deferrals are necessary as the details of future developments in IFRS rate regulated accounting are determined and evaluated.

The Company is continuing to assess the financial reporting impacts of the adoption of IFRS on its financial statements. The Company does anticipate significant changes to those accounting policies which are unique to rate regulated entities under Canadian GAAP. In particular, the adoption of IFRS is expected to result in significant changes to the capitalization and other accounting policies applicable to self constructed property, plant and equipment. The Company also anticipates a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable or estimable.

4. Rate Setting

The rates of the Company's electricity distribution business are subject to regulation by the OEB. The Company purchases electricity from the Independent Electricity System Operator (the IESO) at spot market or prescribed rates and charges its customers unbundled rates. The unbundled rates include the actual cost or prescribed cost of the electricity, transmission, wholesale market service charges and an approved rate for electricity distribution. The cost of electricity transmission and connection charges and debt retirement charges are collected by Brantford Power Inc. and remitted to the IESO and the Ontario Electricity Financial Corporation (the OEFC) respectively. The Company retains the distribution charges reflected on the customer billings. The distribution charges also incorporate, where applicable, OEB approved rate adders or riders that are necessary to dispose of regulatory assets and liabilities.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the distribution rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from customers in the future and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts of expenses incurred in different periods than would be the case had the company been unregulated.

Specific regulatory assets and liabilities are disclosed in note 9.

In the absence of rate regulation, distribution revenue would have been lower by $4,144,991 (2011 - $3,367,713), cost of power would have been lower by $2,235,587 (2011 - $985,277), other income would have been lower by $7,091 (2011 - $14,601), distribution operations and maintenance would have been higher by $193,256 (2011 - $51,215), general administration would have been higher by $17,195 (2011 - $57,877), amortization would have been higher by $321,320 (2011 - $315,364), and interest income would have been higher by $5,824 (2011 - $48,936). The net effect, in the absence of rate regulation, is a pre-tax decrease in net income for 2012 of $2,442,442 (2011 - $2,772,557).

The Company administers several programs through the Ontario Power Authority (OPA) conservation project. The revenues and expenses related to these programs are not subject to the regulation of the OEB.

On October 21, 2009 the Company filed an application for 2010 rates on the basis of the OEB's third generation Incentive Regulation Mechanism (IRM) policy which incorporates an OEB-approved formula that considers inflation and efficiency targets. On April 12, 2010, the OEB released its decision. This decision included the repayment of $7,650,132 in regulatory liabilities over a two year period. The revised rates were approved with an effective date of May 1, 2010.

4. Rate Setting - continued

On October 29, 2010 the Company filed an application for 2011 rates also on the basis of the OEB's third generation IRM policy. On March 28, 2011, the OEB released its decision. This decision included the repayment of $1,192,282 in regulatory liabilities. The revised rates were approved with an effective date of May 1, 2011.

On November 10, 2011 the Company filed an application for 2012 rates also on the basis of the OEB's third generation IRM policy. On April 19, 2012, the OEB released its decision. This decision included the repayment of $5,841,761 in regulatory liabilities. Included in this total is $2,021,450 in PILs that resulted from the OEB PILs proceeding concluded during 2011. The PILs amount was previously not reflected in the regulatory liabilities total and reduced 2012 distribution revenue in the amount of $1,217,320 as it is returned to the customers. The revised rates were approved with an effective date of May 1, 2012.

The Company is in the process of preparing a cost of service rate application for 2013 distribution rates.

5. Property, Plant and Equipment

	2012			2011
	Cost	Accumulated Amortization	**Net Book Value**	Net Book Value
	$	$	**$**	$
Land	181,961	-	**181,961**	181,961
Buildings	1,163,732	194,532	**969,200**	992,474
Transformer station	4,507,912	893,531	**3,614,381**	3,727,079
Distribution stations	74,427	30,025	**44,402**	46,883
Distribution lines - overhead	29,840,112	10,814,369	**19,025,743**	18,891,807
Distribution lines - underground	34,084,914	10,386,668	**23,698,246**	22,983,145
Distribution transformers	17,824,165	6,365,512	**11,458,653**	11,682,006
Distribution meters	4,033,045	1,004,368	**3,028,677**	2,973,728
Vehicles	2,928,990	2,132,692	**796,298**	891,003
Office furniture	3,113	314	**2,799**	-
Computer hardware	103,440	25,860	**77,580**	-
Tools and other equipment	841,329	270,434	**570,895**	591,112
Capital contributions	(4,457,124)	(863,069)	**(3,594,055)**	(3,166,790)
Other utility plant	54,756	-	**54,756**	54,756
Work in progress	13,086	-	**13,086**	24,008
	91,197,858	31,255,236	**59,942,622**	59,873,172

6. Intangible Assets

	2012			2011
	Cost	Accumulated Amortization	**Net Book Value**	Net Book Value
	$	$	**$**	$
Land rights and easements	94,991	7,748	**87,243**	5,968
Stranded meters	5,381,879	2,215,921	**3,165,958**	3,237,191
Software	635,467	326,271	**309,196**	236,152
	6,112,337	2,549,940	**3,562,397**	3,479,311

7. Restructuring

In December 2011, the City announced plans to restructure the Company to simplify its compliance with the OEB's Affiliate Relationships Code for Electricity Distributors and Transmitters. Effects of the restructuring are detailed below.

The City transferred a total of 55 positions, one effective January 1, 2012 and the remainder on April 1, 2012 impacting 52 permanent and 3 part-time or contract employees.

The transfer of employees resulted in $1,276,000 in post employment benefit obligation including vested sick leave obligation of $163,000 being assumed by the Company. The Company received $198,905 plus interest for the vested sick leave from the City during November 2012.

The Company also received $1,161,705 plus interest for IT Services Equipment and Customer Service Equipment that had been included in the City's reserves as at March 31, 2012.

The City transferred ownership of certain assets including computer hardware and office furniture effective December 31, 2012. The majority of the assets had a zero net book value with the exception of certain computer hardware related to the customer billing system. The net book value of this hardware was $92,614. The City transferred this over for no cash consideration.

Contributed surplus	
Employee future benefits	(1,113,000)
Equipment reserves	1,161,705
Computer hardware	92,614
Net contributed surplus	141,319

8. Related Party Transactions

The Company is a wholly owned subsidiary of Brantford Energy Corporation and Brantford Energy Corporation is wholly owned by The Corporation of the City of Brantford (the City). Brantford Energy Corporation also owns Brantford Hydro Inc. and Brantford Generation Inc.

The Company obtains certain administrative and management services from the City and Brantford Energy Corporation. As a result of the restructuring, certain related party transactions ceased following the transfer of applicable City employees to the Company. The Company also provides services to the City, Brantford Generations Inc. and Brantford Hydro Inc. These services were made in the normal course of business and have been recorded at the exchange amounts.

The Company has entered into a shared services agreement with the City, whereby the City will provide administrative, customer care, maintenance and operational services for the Company. The exchange amount for these services has been set out in the agreement. Total charges from the City under this shared agreement were $4,538,547 (2011 - $8,063,255). As at December 31, 2012 the balance owing to the City for these services was $896,904 (2011 - $1,489,970).

For the year ended December 31, 2012, the Company provided electricity to the City in the amount of $5,899,740 (2011 - $5,471,768). The Company also provided other services to the City in the amount of $303,199 (2011 - $138,410).

For the year ended December 31, 2012, the Company paid property tax to the City in the amount of $16,176 (2011 - $16,868)

The Company obtains management services from Brantford Energy Corporation. Total charges for these services were $174,754 (2011 - $151,041). As at December 31, 2012 the balance owing to Brantford Energy Corporation for these services was $53,630 (2011 - $23,312).

The Company charges pole rental fees to Brantford Hydro Inc. These rental fees allow fibre optic cables to be attached to the Company's distribution assets. Total rental fees for this access were $43,694 (2011 - $42,532). The Company also provides billing and collecting services to Brantford Hydro Inc. for its water heater rental and sentinel light rental divisions. As at December 31, 2012 the balance owing to Brantford Hydro Inc. for these customer billings was $61,376 (2011 - $58,526).

For the year ended December 31, 2012, the Company provided electricity to Brantford Generation Inc. in the amount of $120,100 (2011 - $104,059). A long term customer deposit of $6,955 (2011 - $6,955) has been paid to the Company from Brantford Generation Inc.

For the year ended December 31, 2012, the Company purchased electricity from Brantford Generation Inc. in the amount of $2,131,230 (2011 - $1,641,833). As of December 31, 2012 the balance owing to Brantford Generation was $213,439 (2011 - $192,299).

9. Regulatory Assets and Liabilities

Based on existing regulatory orders or the expectation of future regulatory orders, the Company has recorded the following amounts, net of income tax and amortization where applicable, which are expected to be recovered from or refunded to customers:

	2012 $	2011 $
Regulatory assets		
Retail Market Settlement		
Retail settlement variance account - Global Adjustment	**806,074**	-
Retailer cost variance accounts	**350,993**	339,637
Other		
Smart meters	**3,058,577**	3,048,342
Distribution revenue rate change	**667,068**	527,214
Special purpose charge	-	19,478
Lost Revenue Adjustment Mechanism (LRAM)	**95,503**	-
Other regulatory assets	**240,412**	212,657
Net regulatory assets	**5,218,627**	4,147,328

	2012 $	2011 $
Regulatory liabilities		
Retail Market Settlement		
Retail settlement variance accounts	**3,712,541**	4,265,592
Retail settlement variance account - Global Adjustment	-	205,504
Other		
Regulatory future income tax liability	**505,931**	509,205
Regulatory liabilities refundable through approved rate riders	**1,961,610**	2,349,523
Net regulatory liabilities	**6,180,082**	7,329,824

Retail settlement variance accounts

The retail settlement variance accounts represent differences between charges billed to customers using the prescribed prices as outlined in the OEB's Retail Settlement Code and the actual costs billed to Brantford Power Inc. by the IESO.

Retail cost variance accounts

The retailer cost variance accounts represent differences between charges billed to retailers using the prescribed prices as outlined in the OEB's Retail Settlement Code and the actual costs paid by Brantford Power Inc. to operate and maintain the systems related to the retail market.

9. Regulatory Assets and Liabilities - continued

Smart meters

On April 12, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and approved a monthly rate adder charge of $0.28 per metered customer for the Company. Effective May 1, 2009, the OEB increased the monthly adder to $1.00 per metered customer. Effective May 1,2010, the OEB increased the monthly adder to $2.07 per metered customer. Effective May 1, 2011, the OEB maintained the monthly adder at $2.07 per metered customer. Effective May 1, 2012, the OEB removed the monthly adder.

The Company has recorded a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder. These expenditures and recoveries will continue to be reported as regulatory assets or liabilities until the Company applies to the OEB to redistribute the amounts to capital or operations.

Distribution revenue rate change

On February 25, 2009, Brant County Power Inc. (BCPI) filed a motion with the OEB to review and vary the Company's 2008 Electricity Distribution Rates. BCPI disputed the rates they were being charged as well as the date that the Company could bill retroactively. The OEB released it decision and order related to this motion on August 10, 2010. The decision allowed the Company to record a regulatory asset consisting of the revenue deficiency between the rates that were approved during the 2008 cost of service application for the Company's embedded distributor and the rates that were approved as a result of the BCPI motion.

9. Regulatory Assets and Liabilities - continued

Special purpose charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge (SPC) assessment under Section 26.1 of the OEB Act, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company the amount of $376,534 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10 (the SPC Regulation). In accordance with Section 9 of the SPC Regulation, the Company was allowed to recover this balance. The initial recovery was completed as at April 30, 2011. The Company is recovering the residual balance in this account through rate riders effective May 1, 2012 to April 30, 2013.

Lost Revenue Adjustment Mechanism

On April 26, 2012, the OEB issued *The Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-003) approving the creation of an LRAM variance account. The purpose of this account is to track the distribution revenues that are lost as a result of Ontario Power Authority (OPA) conservation programs.

Regulatory future income tax liability

The Company has recorded a regulatory liability account that relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

Regulatory liabilities refundable through approved rate riders

The regulatory liabilities refundable through approved rate riders consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The amount is subject to carrying charges following the OEB prescribed methodology and related rates.

10. Long-Term Debt

	2012 $	2011 $
Note payable, bearing interest at 5.87%, repayable to the City, interest only payable annually - due February, 2016	**24,189,168**	24,189,168
Royal Bank, non-revolving term facility with interest at prime repayable in quarterly instalments, due January, 2018	**3,986,899**	4,361,278
Royal Bank, non-revolving term facility with interest at prime repayable in quarterly instalments, due November, 2016	**562,093**	683,657
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest at 5.14% repayable in semi annual instalments due December, 2032	**2,151,048**	2,212,664
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest at 4.95% repayable in semi annual instalments due December, 2050	**4,728,626**	4,769,966
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest at 3.46% repayable in semi annual instalments due October, 2027	**5,564,189**	5,301,704
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest at 3.90% repayable in semi annual instalments due December, 2042	**3,988,486**	-
	45,170,509	41,518,437
Less current portion	**991,134**	598,986
	44,179,375	40,919,451

The City has an option to extend the maturity date of the promissory note for successive five year periods. The City also has the option to convert the principal sum outstanding into common shares of the Company at a conversion ratio of $ 100 per common share. Interest payable to the City of $1,419,904 (2011 - $1,427,564) was outstanding as at December 31, 2012.

The Company entered into a swap agreement during 2006 with Royal Bank to hedge against exposure to interest rate fluctuations. The agreement represents a notional principal amount of $ 5,900,000. Under the terms of the agreement, the company has contracted to pay interest at a fixed rate of 4.71% while receiving a variable rate equivalent to the one month Canadian Dollar Offered Rate to be repriced quarterly.

10. Long-Term Debt - continued

The Company entered into a second swap agreement during 2006 with Royal Bank to hedge against exposure to interest rate fluctuations. The agreement represents a notional principal amount of $ 1,200,000. Under the terms of the agreement, the company has contracted to pay interest at a fixed rate of 4.97% while receiving a variable rate equivalent to the one month Canadian Dollar Offered Rate to be repriced quarterly.

These credit facilities are secured by general security agreement over all assets of the Company and an assignment of related fire insurance.

Estimated principal repayment requirements are as follows:

	$
2013	991,134
2014	1,038,479
2015	1,088,567
2016	25,330,598
2017	1,034,099
Thereafter	15,687,632

11. Vested Sick Leave

The Company is obligated to pay certain employees their sick leave banks that were frozen on December 31, 1998 by the former Hydro-Electric Commission of the City of Brantford. The sick leave banks will be paid out at retirement at the employee's pay rate at time of retirement.

12. Employee Future Benefits

The Company acquired various life insurance, health care related and dental coverage plan liabilities for certain retired employees of the former Hydro-Electric Commission of the City of Brantford. Travel, dental, vision and semi-private health care coverage is continued until the retiree reaches 65 years of age. Life insurance and extended health care coverage is continued until the retiree's death. The Company is also obligated to provide post retirement benefits to active employees.

The Company measures the accrued benefit obligation for accounting purposes as of December 31 of each year. The accrued benefit obligation as at December 31, 2012 and the expense for the period ended December 31, 2012 are based on actuarial valuations done as at January 1, 2012 and April 1, 2012.

The obligation is unfunded since no assets have been segregated and restricted to provide the post-retirement benefits.

Significant Assumptions

The key weighted-average assumptions used by the Company for the measurement of the benefit obligation and benefit expense are summarized as follows:

	2012	2011
	$	$
To determine benefit obligation at end of year		
Discount rate	**3.50%**	3.25%
Assumed long-term rate of return on assets	**N/A**	N/A
To determine benefit expense (income) for the year		
Discount rate	**3.25%**	4.5%
Assumed long-term rate of return on assets	**N/A**	N/A
Rate of increase in future compensation	**N/A**	N/A
Health care cost trend rates at end of year		
Initial rate	**9.00%**	6.45%
Ultimate rate	**5.00%**	4.75%
Year ultimate rate reached	**2019**	2013

Sensitivity Analysis	**Change in Obligation**	**Change in Expense**
	$	$
Impact of 1% increase in assumed health care trend rate	127,178	20,341
Impact of 1% decrease in assumed health care trend rate	(107,822)	(16,815)

12. Employee Future Benefits - continued

	2012 $	2011 $
Change in benefit obligation		
Benefit obligation at beginning of year	**1,684,720**	1,734,220
Opening benefit obligation adjustment to reflect full valuation versus extrapolation	**(758,258)**	-
Obligation assumed on transferred employees	**1,113,000**	-
Accrual for service	**73,635**	-
Interest cost on benefit obligation	**59,043**	77,863
Benefits paid	**(25,100)**	(58,616)
Actuarial (gain) loss on accrued benefit obligation	**(422,878)**	(68,747)
Benefit obligation at end of year	**1,724,162**	1,684,720
Change in fair value of assets		
Fair value of assets at beginning of year	**-**	-
Employer contributions	**25,100**	58,616
Benefits paid	**(25,100)**	(58,616)
Fair value of assets at end of year	**-**	-
Reconciliation of funded status to accrued benefit liability		
Deficit of fair value of assets over benefit obligation at end of year	**1,724,162**	1,684,720
Unamortized actuarial gain (loss)	**395,054**	(786,653)
Accrued benefit liability at end of year	**2,119,216**	898,067
Reconciliation of accrued benefit liability		
Accrued benefit liability at beginning of year	**898,067**	817,515
Liability assumed on transferred employees	**1,113,000**	-
Benefit expense recognized	**132,678**	139,168
Benefits paid	**(25,100)**	(58,616)
Other	**571**	-
Accrued benefit liability at end of year	**2,119,216**	898,067
Annual benefit expense		
Interest cost on benefit obligation	**59,043**	77,863
Accrual for services	**73,635**	-
Actuarial loss	**-**	61,305
Benefit expense recognized	**132,678**	139,168

12. Employee Future Benefits - continued

Cash payments		
Benefit premiums paid	**109,454**	91,633

13. Contingencies and Commitments

General Liability Insurance

The Company has obtained general liability and enhanced directors and officers insurance coverage from the Municipal Electric Association Reciprocal Insurance Exchange (The Mearie Group) expiring January 1, 2014. The Mearie Group is an insurance reciprocal whereby all members through the unincorporated group share risks with each other. Members of the Mearie Group are assessed a premium deposit at policy execution. Should the group experience losses that are in excess of the accumulated premium deposits of its members combined with reserves and supplementary insurance, members would be assessed a supplementary or retro assessment on a pro-rata basis for the years in which the Company was a member.

As at December 31, 2012, the Company has not been made aware of any additional assessments. Participation in The Mearie Group covers a three year underwriting period which expires on January 1, 2016.

Smart Meter Initiative

The OEB had mandated that the Company bill Time of Use Prices using "Smart Meter" electricity meters and the Provincial Meter Data Management/Repository effective July 2011. The Company was granted an extension of the effective date and proceeded with billing Time of Use Pricing during December 2011.

The Company has installed approximately 37,185 (2011 - 37,134) Smart Meters as of the end of 2012 and anticipates having installed a total of 37,240 Smart Meters upon completion of its mass deployment.

14. Share Capital

Authorized
Unlimited number of common shares

	2012	2011
	$	$
Issued		
1,001 common shares	**22,437,505**	22,437,505

15. Accumulated Other Comprehensive Loss

	2012 $	2011 $
Balance at beginning of year	**(518,279)**	(374,658)
Other comprehensive gain (loss), net of tax	**125,113**	(143,621)
Balance at end of year, net of tax	**(393,166)**	(518,279)

16. Pension Plan

The Company participates in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer plan, on behalf of its employees. The plan is a contributory defined benefit pension plan. Contributions are 8.3% for employee earnings below the year's maximum pensionable earnings and 12.8% thereafter. The contribution rates changed to 9.0% for employee earnings below the year's maximum pensionable earnings and 14.6% thereafter for 2013. During 2012, the Company expensed contributions totaling $255,438 (2011 - $nil) made to OMERS in respect of the employer's required contributions to the plan.

17. Electricity Distribution Service Charges

The company is licensed by the OEB to distribute electricity. As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company may file to recover uncollected debt retirement charges from OEFC once each year. Otherwise, the Company is unable to recover uncollected amounts formerly remitted to these third parties. The Company retains only its electricity distribution service charge that is regulated by the OEB.

Electricity distribution service charges comprise:

	2012 $	2011 $
Gross customer billings	**111,713,232**	105,109,712
Less pass through charges billed by the Company		
Electricity charges paid through to generators	**(73,268,847)**	(66,724,020)
Transmission and miscellaneous charges	**(11,354,826)**	(10,618,115)
Market service charges	**(6,200,632)**	(6,186,857)
Debt retirement charges	**(6,551,933)**	(6,422,286)
Total electricity distribution service charges	**14,336,994**	15,158,434

18. Statement of Cash Flows

	2012 $	2011 $
Changes in non-cash working capital		
Accounts receivable	**(1,570,183)**	1,109,739
Unbilled revenue	**79,240**	358,818
Inventories	**(387,694)**	100,514
Prepaid expenses	**10,347**	39,379
Accounts payable and accrued liabilities	**2,775,071**	(1,523,889)
Accounts payable to the City of Brantford	**(593,066)**	(207,670)
Interest payable to the City of Brantford	**(7,660)**	(84,259)
Due to affiliates	**(4,219)**	285,130
Payments in lieu of corporate income taxes	**693,177**	(677,733)
	995,013	(599,971)

19. Amortization

	2012 $	2011 $
Amortization of capital assets	**3,595,408**	3,842,300
Amortization of capital assets charged to distribution operations and maintenance	**218,541**	271,416
	3,813,949	4,113,716

20. Capital Disclosures

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system;
- ensure compliance with covenants related to its credit facilities; and
- closely align its capital structure with the debt to equity structure deemed by the OEB.

As at December 31, 2012, the Company's definition of capital includes shareholder's equity and long-term debt. This definition remains unchanged from prior years. As at December 31, 2012, shareholder's equity amounts to $35,141,629 (2011 - $34,278,132) and long-term debt, amounts to $45,170,509 (2011 - $41,518,437). The Company's capital structure as at December 31, 2012 is 56% debt and 44% equity (2011 - 55% debt and 45% equity). There have been no changes in the Company's approach to capital management during the year.

The Company's long-term debt agreements include both financial and non-financial covenants. As at December 31, 2012 and as at December 31, 2011, the Company was in compliance with all covenants.

21. Financial Instruments

All financial instruments are initially recorded on the balance sheet at fair value except for certain related party transactions. They are subsequently valued either at fair value or amortized cost depending on the classification selected by the Company for the financial instrument. All financial instruments are classified into one of the five categories: held-for-trading, loans and receivables, other liabilities, held-to-maturity investments or available-for-sale financial assets

Held-for-trading (HFT) financial instruments are financial assets and financial liabilities typically acquired with the objective of resale or short-term buyback. The carrying amount is recorded at fair value determined using market prices. Interest earned and gains and losses incurred are recognized in net income. Cash and cash equivalents and special deposits are designated as financial assets held-for-trading and are measured at fair value with changes being recorded in net income at each period end. Derivative liabilities are designated as financial liabilities held-for-trading and are measured at fair value with changes being recorded in other comprehensive income at each period end.

Loans and receivables (LR) are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date, or on demand, usually with interest. Loans and receivables are measured at amortized cost. Accounts receivable and unbilled revenue are classified as loans and receivables and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost.

Other liabilities (OL) are promises to repay on specified dates or on demand usually with interest. Accounts payable and accrued liabilities and accounts payable to the City of Brantford, interest payable to the City of Brantford and due to affiliates are classified as other liabilities and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost. Long-term debt and customer deposits are also classified as other liabilities. After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

Held-to-maturity (HTM) financial assets have fixed or determinable payments and maturity, and management's intention and ability are to hold to maturity. These financial assets are measured at amortized cost. The Company does not hold any financial assets under this classification.

Available-for-sale (AFS) instruments are non-derivative financial assets that are designated as available-for-sale or that are not classified as loans and receivables, held-to-maturity investments or held-for-trading financial assets. Available-for-sale instruments are measured at fair value with unrealized gains and losses recognized in OCI. The Company does not hold any financial assets under this classification.

21. Financial Instruments - continued

Interest Rate Risk

Interest is paid on customer deposits at a market rate reset quarterly as directed by the Ontario Energy Board.

Two term facility loans bear interest at floating rates and thus, the carrying values approximate fair values. However, the Company has entered into two interest rate swap transactions, derivative instruments designated as a cash flow hedges, the effect of which is to fix the interest rate on the first $3,994,000 term facility loan at 4.71% and the second $564,000 term facility loan at 4.97%. The potential replacement cost to Brantford Power Inc. of the interest rate swaps, representing estimated fair value as presented on the balance sheet, was $554,860 (2011 - $713,683), which was in the favour of Royal Bank. Net unrealized gain in fair value of $156,203 (2011 - loss of $191,491) is presented in current year Other Comprehensive Loss. The Company entered into these interest rate swap transactions to fix the interest rates over the long term and intends to hold these to maturity at which time there should be no replacement cost.

Credit Risk

The Company grants credit to its customers in the normal course of business and monitors their financial condition and reviews the credit history of new customers. The Company is currently holding customer deposits on hand in the amount of $1,860,225 (2011 - $2,073,612) which is reflected on the Balance Sheet. Customer deposits are limited to those allowed under the OEB's Retail Settlement Code. Allowances of $682,000 (2011 - $680,000) are also maintained for potential credit losses. The Company's accounts receivable do not reflect the concentrated risk of default from exposure to large customers. At December 31, 2012, the outstanding amounts receivable from the largest ten customers represented $2,284,332 or 31% (2011 - $1,923,019 or 27%) of the total outstanding accounts receivable. Management believes that it has adequately provided for any exposure to normal customer and retailer credit risk.

Liquidity Risk

The Company's objective is to have sufficient liquidity to meet its liabilities when due. The Company monitors its cash balances and cashflows generated from operations to meet its requirements.

21. Financial Instruments - continued

Prudential Support

Brantford Power Inc. is required, through the Independent Electricity System Operator (IESO), to provide security to mitigate the company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Company fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letter of credit. As at December 31, 2012, the Company provided prudential support in the form of a bank letter of credit of $13,057,140 (2011 - $9,375,721).

Revolving Term Facility

As at December 31, 2012, the Company has been authorized for a revolving term facility of $7,000,000 of which NIL had been drawn upon. The facility bears interest at prime and is secured by a general security agreement over all assets of the Company and assignment of related fire insurance.

Fair Value of Other Financial Instruments

a) Establishing fair value

The carrying values of cash and cash equivalents, accounts receivable, special deposits, accounts payable and accrued liabilities, accounts payable to the City of Brantford, interest payable to the City of Brantford, and due to affiliates approximate their fair values due to the immediate or short-term maturity of these financial instruments.

Fair values for other financial instruments, detailed below, have been estimated with reference to quoted market prices for actual or similar instruments where available, except for certain related party transactions.

Customer deposits fair value equals carrying value. Interest is paid on deposits on a monthly basis at a market rate, reset quarterly, as directed by the Ontario Energy Board.

The fixed rate long-term debt facility, maturing December 2032, funded by the Ontario Infrastructure and Lands Corporation (OILC) has an estimated fair value of $2,448,900 (carrying value - $2,151,048). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 3.80% per annum, (actual rate – 5.14% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

21. Financial Instruments - continued

The fixed rate long-term debt facility, maturing December 2050, funded by the OILC has an estimated fair value of $5,382,500 (carrying value - $4,728,626). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 4.00% per annum, (actual rate – 4.95% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

The fixed rate long-term debt facility, maturing October 2027, funded by the OILC has an estimated fair value of $5,581,600 (carrying value - $5,564,189). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 3.33% per annum, (actual rate – 3.46% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

The fixed rate long-term debt facility, maturing December 2042, funded by the OILC has an estimated fair value of $4,000,000 (carrying value - $3,988,486). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 3.90% per annum, (actual rate – 3.90% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

The promissory note payable to the Corporation of the City of Brantford, classified as an OL, is valued at face value. It is not practicable within constraints of timeliness or cost to measure reliably the fair value of this financial liability that originated in a related party transaction.

Construction advances funded by the OILC, classified as OL are valued at face value. Upon completion of construction the term of the loan will be 15 years.

The fair value of derivative instruments is calculated using pricing models that incorporate current market prices and the contractual prices of the underlying instruments, the time value of money and yield curves.

b) Fair value hierarchy

Financial instruments recorded at fair value on the Balance Sheet are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (ie as prices) or indirectly (ie derived from prices);

21. Financial Instruments - continued

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

The following table presents the financial instruments recorded at fair value in the Balance Sheet, classified using the fair value hierarchy described above:

	Level 1	Level 2	Level 3	Total financial assets and liabilities at fair value
	$	$	$	$
Financial Assets				
Cash and cash equivalents	13,935,062	-	-	13,935,062
Special deposits	1,860,225	-	-	1,860,225
Total financial assets	**15,795,287**	-	-	**15,795,287**
Financial liabilities				
Customer deposits	1,860,225	-	-	1,860,225
Total financial liabilities	**1,860,225**	-	-	**1,860,225**

During the year, there has been no transfer of amounts between Level 1 and Level 2 and no financial assets or liabilities have been identified as Level 3.

22. Payments in Lieu of Corporate Income Taxes

The Company's income tax expense for the year ended December 31, 2012 consists of the following:

Temporary differences which give rise to future income tax assets and liabilities are as follows:

	2012	2011
	$	$
Regulatory assets	**322,953**	643,641
Cumulative eligible capital	**170,390**	156,910
Allowance for doubtful accounts	**180,730**	178,500
Property, plant and equipment	**697,499**	1,063,135
Employee future benefits	**594,940**	244,390
Unrealized losses on derivative liabilities	**140,530**	171,620
Future income tax assets	**2,107,042**	2,458,196

Distributed as such:		
Future payments in lieu of corporate income tax asset		
Current	**180,730**	178,500
Non-current	**1,926,312**	2,279,696
	2,107,042	2,458,196

The impact of differences between the Company's reported payments in lieu of corporate income taxes and the expense that would otherwise result from the application of statutory rates is as follows:

	2012	2011
	$	$
Income tax expense at the combined basis federal and provincial statutory tax rate	**488,685**	930,126
Impact of change in rates	**26,803**	97,276
Capital cost allowance in excess of amortization	**(423,286)**	(140,633)
Net change in tax reserves	**280,126**	(95,268)
Provision relating to prior periods	**121,889**	(21,890)
Other	**2,813**	423
	497,030	770,034

23. Comparative Figures

Certain prior year figures have been reclassified to conform with the current year's presentation.

ATTACHMENT D

REFERENCE: 1.0 Energy Probe-7a

Consolidated Financial Statements of

Brantford Energy Corporation

December 31, 2012

Brantford Energy Corporation
Table of Contents
December 31, 2012

Brantford Energy Corporation
Management Report
December 31, 2012

The accompanying consolidated financial statements are the responsibility of management of Brantford Energy Corporation (the Company). In management's opinion, these consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Management has selected accounting principles and methods that are appropriate to the Company's circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The notes to the consolidated financial statements and any other supplementary information presented are consistent with that in the consolidated financial statements.

The Company maintains systems of internal accounting and administrative controls that are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, that transactions are properly authorized and that the Company's assets are properly accounted for and adequately safeguarded.

The consolidated financial statements have been examined by Deloitte LLP, the external auditors of the Company. The responsibility of the external auditors is to express their opinion on whether the consolidated financial statements are fairly presented, in all material respects, in accordance with Canadian generally accepted accounting principles.

The board of directors, through the finance committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The finance committee meets periodically with management, as well with the external auditors to satisfy itself that each party is properly discharging its responsibilities with respect to internal controls and financial reporting. The finance committee also reviews the consolidated financial statements and annual report and recommends their approval to the board of directors. Deloitte LLP has full and free access to the finance committee, with and without the presence of management.

Ted Salisbury
Chief Executive Officer
May 2, 2013

Catherine Barker-Hoyes, CGA
Chief Financial Officer
May 2, 2013

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Independent Auditor's Report

To the Board of Directors of
Brantford Energy Corporation

We have audited the accompanying consolidated financial statements of Brantford Energy Corporation which comprise the consolidated balance sheet as at December 31, 2012 and the consolidated statements of operations, retained earnings, comprehensive income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's 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, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Brantford Energy Corporation as at December 31, 2012 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
May 2, 2013

Brantford Energy Corporation
Consolidated Balance Sheet
as at December 31, 2012

Assets	**2012**	2011
	$	$
Current Assets		
Cash and cash equivalents	**16,441,207**	11,277,852
Accounts receivable	**9,049,174**	7,486,017
Unbilled revenue	**8,616,119**	8,690,152
Inventories	**1,106,630**	720,936
Special deposits	**1,117,443**	1,155,522
Prepaid expenses	**118,771**	128,279
Payments in lieu of corporate income taxes	**527,434**	1,315,922
Future payments in lieu of corporate income taxes - note 23	**185,235**	182,438
	37,162,013	30,957,118
Property, plant and equipment - note 5	**74,585,257**	74,905,342
Other Assets		
Regulatory assets - note 9	**5,218,627**	4,147,328
Long-term special deposits	**742,782**	918,090
Long-term prepaid expenses	**260,257**	206,458
Future payments in lieu of corporate income taxes - note 23	**2,107,908**	2,516,492
Intangible assets - note 6	**3,562,397**	3,479,311
	11,891,971	11,267,679
	123,639,241	117,130,139

Brantford Energy Corporation
Consolidated Balance Sheet
as at December 31, 2012

Liabilities and Shareholder's Equity	2012	2011
	$	$
Current Liabilities		
Accounts payable and accrued liabilities	**12,323,981**	10,117,760
Accounts payable to the City of Brantford - note 8	**1,951,673**	2,187,578
Interest payable to the City of Brantford - note 10	**1,501,362**	1,509,022
Current portion of customer deposits	**1,119,383**	1,159,272
Current portion of deferred revenue	**16,224**	8,925
Current portion of vested sick leave - note 12	**145,885**	-
Current portion of long-term debt - note 10	**991,134**	598,986
	18,049,642	15,581,543
Long-term debt - note 10	**58,234,516**	55,174,469
Other Liabilities		
Regulatory liabilities - note 9	**6,180,082**	7,329,824
Long-term customer deposits	**778,277**	952,860
Employee future benefits - note 11	**2,119,216**	898,067
Accumulated vested sick leave credits- note 12	**88,093**	78,512
Deferred revenues	**123,923**	147,446
Derivative liabilities - note 22	**554,860**	713,683
	9,844,451	10,120,392
Contingencies and Commitments - note 13 and 14		
Shareholder's Equity		
Share capital - note 15	**23,895,512**	23,895,512
Retained Earnings	**14,008,286**	12,876,502
Accumulated Other Comprehensive Loss - note 16	**(393,166)**	(518,279)
	37,510,632	36,253,735
	123,639,241	117,130,139

Signed on behalf of the Board:

______________________________ Director

______________________________ Director

Brantford Energy Corporation
Consolidated Statement of Retained Earnings
for the year ended December 31, 2012

	2012	2011
	$	$
Retained Earnings, Beginning of Year	**12,876,502**	11,676,811
Restructuring effects - note 7	**141,319**	-
Net Income	**2,140,465**	2,999,691
Dividends	**(1,150,000)**	(1,800,000)
Retained Earnings, End of Year	**14,008,286**	12,876,502

Brantford Energy Corporation
Consolidated Statement of Operations
for the year ended December 31, 2012

	2012	2011
	$	$
Revenue		
Electricity distribution service charges - note 18	**14,336,994**	15,158,434
Fibre optics and retail service revenue	**2,676,051**	2,517,636
Generation revenue	**2,131,230**	1,641,833
Interest income	**302,221**	299,773
Specific service charges	**407,628**	469,500
Ontario Power Authority conservation programs	**4,020,508**	723,014
Other income	**254,868**	290,956
	24,129,500	21,101,146
Expenses		
Operations and maintenance	**5,101,941**	4,290,738
Billing and collecting	**1,870,898**	1,975,469
General administration	**3,359,983**	2,736,614
Ontario Power Authority conservation programs	**3,683,840**	735,093
Interest on long-term debt	**2,447,964**	2,440,713
Other financing expenses	**172,775**	195,748
Capital tax	**119**	(1,756)
Amortization - note 20	**4,612,187**	4,802,671
	21,249,707	17,175,290
Income before payments in lieu of income taxes	**2,879,793**	3,925,856
Payments in lieu of corporate income taxes		
Current - note 23	**367,905**	(106,516)
Future - note 23	**371,423**	1,032,681
	739,328	926,165
Net income	**2,140,465**	2,999,691

Brantford Energy Corporation
Consolidated Statement of Comprehensive Income
for the year ended December 31, 2012

	2012	2011
	$	$
Net income	**2,140,465**	2,999,691
Other comprehensive income/(loss)		
Unrealized gain/(losses) on derivative instruments designated as cash flow hedges - Note 22	**156,203**	(191,491)
Future (payments)/recoveries in lieu of corporate income taxes	**(31,090)**	47,870
	125,113	(143,621)
Comprehensive income	**2,265,578**	2,856,070

Brantford Energy Corporation
Consolidated Statement of Cash Flows
for the year ended December 31, 2012

	2012 $	2011 $
Operating activities		
Net income	**2,140,465**	2,999,691
Items not affecting cash		
Amortization - note 20	**4,830,728**	5,074,087
Future payments in lieu of corporate income taxes	**371,423**	1,032,681
Gain on disposal of property, plant and equipment	**(565)**	(19,025)
Other items not affecting cash	**1,514,161**	78,162
Working capital provided by operations	**8,856,212**	9,165,596
Changes in non-cash working capital components - note 19	**885,834**	(482,484)
	9,742,046	8,683,112
Investing activities		
Acquisition of property, plant and equipment	**(5,216,944)**	(5,991,733)
Decrease (increase) in regulatory assets	**(1,071,299)**	899,233
Decrease in regulatory liabilities	**(1,149,742)**	(3,679,967)
Decrease in special deposits	**213,387**	434,908
Proceeds from disposal of property, plant and equipment	**565**	19,025
	(7,224,033)	(8,318,534)
Financing activities		
Proceeds of issuance of long-term debt	**4,230,000**	550,000
Capital contributions	**613,494**	295,163
Repayment of long-term debt	**(810,501)**	(567,012)
(Decrease) in customer deposits	**(221,427)**	(433,474)
Increase in deferred revenues	**(16,224)**	76,119
Dividends paid	**(1,150,000)**	(1,800,000)
	2,645,342	(1,879,204)
(Decrease) increase in cash and cash equivalents	**5,163,355**	(1,514,626)
Cash and cash equivalents, beginning of year	**11,277,852**	12,792,478
Cash and cash equivalents, end of year	**16,441,207**	11,277,852
Supplemental Disclosure of Cash Flows		
Interest received	**180,783**	180,215
Interest paid	**2,405,347**	2,384,709
Payments in lieu of corporate income taxes paid	**728,281**	1,462,456

1. Description of Business

On March 1, 2000, Brantford Energy Corporation (the "Company") was incorporated under the Business Corporations Act (Ontario) along with its wholly-owned subsidiary companies, Brantford Power Inc. and Brantford Hydro Inc. A third wholly-owned subsidiary company, Brantford Generation Inc., was incorporated in 2007. The incorporations were pursuant to the provisions of the Energy Competition Act, 1998. The Company is wholly-owned by The Corporation of the City of Brantford.

The principal business of the Company is to oversee the operations of Brantford Power Inc., providing regulated electricity distribution services, Brantford Hydro Inc., providing fibre optics networks, water heater, sentinel lighting and other equipment rental services and Brantford Generation Inc., providing electricity generation.

2. Accounting Policies

Basis of accounting

The financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and policies set forth in the Accounting Procedures Manual issued by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998. Significant accounting policies are summarized below:

Basis of consolidation

These consolidated financial statements reflect the results of Branford Energy Corporation and its subsidiaries. All significant intercompany balances and transactions have been eliminated. The notes to these financial statements are disclosures and policies adopted by Brantford Energy Corporation and, if applicable, the specific subsidiary referenced in the note.

2. Accounting Policies - continued

Use of estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the year. During the years presented, management has made a number of estimates and valuation assumptions including allowance for doubtful accounts receivable, unbilled revenue, useful lives, certain accruals, valuation of financial instruments including derivatives and future income tax liabilities. Estimates are based on historical experience, current trends and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from estimates, including changes as a result of future decisions made by the Ontario Energy Board (the OEB) or the Minister of Energy.

Regulatory policies

Brantford Power Inc. is regulated by the OEB and requires OEB approval for any distribution service rates adjustments. The following accounting policies applicable to rate regulated operations differ from GAAP for companies in an unregulated environment:

Regulatory assets and liabilities

Regulatory assets primarily represent costs that have been deferred because they are expected to be recovered in future rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding wholesale market cost of power incurred by the utility.

Regulatory assets and liabilities will be recognized for rate-setting and financial statement purposes only to the extent allowed by the regulator. Brantford Power Inc. continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, Brantford Power Inc. judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in the results of operations in the period that the assessment is made. Asset and liability balances and current year activities are detailed in Note 9.

2. Accounting Policies - continued

Contributions in aid of construction
Contributions in aid of construction consist of third party contributions towards the cost of constructing Brantford Power Inc. assets. Capital contributions for the year of $605,551 (December 31, 2011 - $265,560) have been recorded as an offset to capital assets. Amortization of contributed capital is recorded at an equivalent rate to that used for amortization of the related assets.

Allowance for use of funds during construction
Brantford Power Inc. capitalizes an allowance for use of funds during construction representing the cost of funds during the construction period. The rate used is prescribed by the OEB and updated on a quarterly basis. The total allowance for use of funds during construction capitalized for the year amounted to $27,434 (December 31, 2011 - $56,469).

Stranded meters
As a result of the OEB's smart meter initiative, Brantford Power Inc. has removed conventional meters and replaced them with smart meters. The net book value of the conventional meters removed from service prior to the end of their useful life has been classified as stranded meters and reallocated from property, plant and equipment to intangible assets. The OEB will allow Brantford Power Inc. to recover the costs of these stranded meters through a future rate application process.

Cash and cash equivalents

Cash and cash equivalents include cash and short-term investments with maturities of three months or less from the date of acquisition.

Inventories

Inventories consist of repair parts, supplies and materials and are valued at the lower of cost or net realizable value determined using a weighted average method. The Company classifies major construction related components of its electricity distribution system and equipment rental business to property, plant and equipment. Brantford Hydro Inc. no longer carries rental equipment inventory as of January 1, 2012. The opening balance of $2,000 is considered obsolete inventory and written off during the period ended December 31, 2012.

2. Accounting Policies - continued

Unbilled revenue

Unbilled revenue for metered services consists of an estimate of customers' consumption of power from the last meter reading during the year to the balance sheet date. Unbilled revenue for other services is an estimate of service fees from the last billing cycle during the year to the balance sheet date.

2. Accounting Policies - continued

Property, plant and equipment

Property, plant and equipment are stated at cost and removed from the accounts when disposed or retired. Costs of assets which are pooled are removed from the accounts at the end of their estimated average service lives. Gains or losses at retirement or disposition of such assets are credited or charged to other income. Amortization is calculated on a straight-line basis over the estimated useful service life as follows.

Distribution buildings	50 years
Transformer station	40 years
Distribution stations	30 years
Distribution lines - overhead	25 years
Distribution lines - underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Vehicles	5-8 years
Tools and other equipment	5-10 years
Office furniture and fixtures	10 years
Computer hardware	4 years
Fibre optics network	25 years
Fibre optics electronics	3-5 years
Water heaters and other rental units	10 years
Generation plant and equipment	20 years
Landfill gas collection system	20 years
Generation building and fixtures	10-20 years
Capital contribution	25 years

Other electric plant and work in progress are amortized when put in service.

2. Accounting Policies - continued

Intangible assets

Intangible assets are recorded at cost and amortized over their estimated useful lives on a straight-line basis. Stranded meters represent distribution meters that have been replaced with smart meters and reallocated from property, plant and equipment. The OEB has allowed these retired meters to remain in rate base for rate making purposes. Amortization is calculated on a straight-line basis over the estimated useful service life as follows.

Land rights	50 years
Stranded meters	25 years
Software	5 years

Long-term prepaid expenses and special deposits

Long-term prepaid expenses consist of service fees paid providing the Company with the right to use non-owned specified tangible assets for future periods. These charges are amortized on a straight-line basis over 10 years representing the expected benefit period.

Long-term prepaid expenses also include current expenditures that relate to future major overhaul procedures that occur when the generating engines reach a designated level of operating hours. These charges will be capitalized when the overhaul is performed and amortized on a straight-line basis over the expected time between overhauls.

Amounts are recorded as special deposits when cash is collected related to customer deposits and are expected to be held for a period exceeding one year.

Impairment of long-lived assets

The Company reviews the valuation of long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. There was no impact on the financial statements as a result of asset impairments for the years ended December 31, 2012 and December 31, 2011.

2. Accounting Policies - continued

Revenue recognition

Distribution and generation revenue is recorded as revenue in the period to which it relates. Distribution revenue includes an estimated accrual for the variable component of the distribution rate based on the electricity delivered but not yet billed to customers from the last meter reading date to the year end. Installation revenue related to fibre optics is capitalized and amortized on a straight line basis over the life of the related capital assets. Any revenues related to the irrevocable right to use fibre optics, are deferred and amortized on a straight line basis over the term of the contract.

Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of billings. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability.

Employee future benefits

Brantford Power Inc. provides post-retirement medical and life insurance benefits to eligible employees. The cost of post-retirement medical and life insurance benefits is expensed using the projected benefit cost method prorated on services.

Brantford Power Inc. has adopted the corridor method of accounting for the actuarially determined gains and losses. Cumulative gains and losses in excess of 10% of the beginning accrued benefit obligation are amortized into expense on a straight-line basis over the expected remaining lifetime of the inactive members receiving benefits under the plan (15 years).

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years, the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. Any adjustment to the liability of its fair value as a result of the passage of time is charged to earnings.

2. Accounting Policies - continued

Payments in lieu of income taxes

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes (PILS) to the Ontario Electricity Financial Corporation (OEFC), beginning on October 1, 2001. These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The Company uses the asset and liability method of accounting for payments in lieu of corporate income taxes. Accordingly, future tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax rates. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. In addition, the effect of future tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the enactment or substantive enactment date.

Comprehensive Income

CICA Handbook Section 1530 requires the presentation of comprehensive income and its components in a financial statement. Comprehensive income is composed of the Company’s net income and other comprehensive income (OCI), which includes unrealized gains and losses on changes in the fair value of the effective portion of cash flow hedging instruments. The Company discloses comprehensive income in the financial statement “Statement of Comprehensive Income”. The cumulative changes in OCI are included in accumulated other comprehensive income net of tax (AOCI), which is presented as a category of Shareholder's equity on the Company’s Balance Sheet.

2. Accounting Policies - continued

Financial Instruments

The Corporation designates its financial instruments in one of the following five categories: (i) held for trading (HFT); (ii) available for sale (AFS); (iii) held to maturity (HTM); (iv) loans and receivables (LR); or (v) other liabilities (OL). All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value, with any change in fair value recognized in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

The Company has elected to add transaction costs related to financial instruments classified as other than HFT to the carrying amount of the financial instrument.

The Company has elected to use settlement-date accounting for regular-way purchases and sales of financial assets.

3. Future Changes in Accounting Framework

Changes in accounting policies

In July 2012, the Ontario Energy Board issued a letter to the province's local distribution companies (LDC's) that provides direction on permitted accounting policies for depreciation expense and capitalization beginning in 2013. In this letter, the OEB states that it will require all LDC's to adopt IFRS-compliant depreciation and capitalization accounting policies effective January 1, 2013, regardless of whether the LDC has chosen to defer the adoption of IFRS as permitted by the AcSB. The OEB also approved the use of a new variance account to capture the financial differences arising as a result of adopting IFRS-compliant accounting policies in 2013. This variance account is to be disposed of as part of the LDC's next rate rebasing. Therefore, there will be no impact to net income as a result of these accounting policy changes.

As such, Brantford Power Inc. will adopt IFRS-compliant accounting policies for depreciation and capitalization effective January 1, 2013. These policies will be selected in accordance with International Accounting Standard 16, "Property, Plant and Equipment" ("IAS 16"). IAS 16 provides more definitive guidance with respect to cost capitalization and componentization for depreciation purposes than that currently followed under Canadian GAAP.

Due to the absence of rate-regulated accounting guidance within Canadian GAAP, Brantford Power Inc. follows regulatory accounting guidance found under US GAAP. In accordance with US GAAP Accounting Standards Codification Section 980, "Regulated Operations," the Company will adopt these changes prospectively with no retrospective restatement of prior periods.

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian accounting Standard Board (AcSB) confirmed that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP effective January 1, 2011. Subsequently, the AcSB issued several optional deferrals in adoption of IFRS for rate-regulated entities. BEC and BPI qualify for these deferrals and have elected to defer adoption for fiscal 2012 and will determine each year whether future deferrals are necessary as the details of future developments in IFRS rate regulated accounting are determined and evaluated.

3. Future Changes in Accounting Policy - continued

The Company is continuing to assess the financial reporting impacts of the adoption of IFRS on its financial statements. The Company does anticipate significant changes to those accounting policies which are unique to rate regulated entities under Canadian GAAP as well to those accounting policies that are not unique to rate regulated entities under Canadian GAAP. The adoption of IFRS is expected to result in significant changes to the capitalization and other accounting policies applicable to property, plant and equipment and the revenue recognition of installation fees. The Company also anticipates a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable or estimable.

4. Rate Setting

The rates of Brantford Power Inc.'s electricity distribution business are subject to regulation by the OEB. Brantford Power Inc. purchases electricity from the Independent Electricity System Operator (the IESO) at spot market or prescribed rates and charges its customers unbundled rates. The unbundled rates include the actual cost or prescribed cost of the electricity, transmission, wholesale market service charges and an approved rate for electricity distribution. The cost of electricity transmission and connection charges and debt retirement charges are collected by Brantford Power Inc. and remitted to the IESO and the Ontario Electricity Financial Corporation (the OEFC) respectively. Brantford Power Inc. retains the distribution charges reflected on the customer billings. The distribution charges also incorporate, where applicable, OEB approved rate adders or riders that are necessary to dispose of regulatory assets and liabilities.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the distribution rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. Brantford Power Inc.'s regulatory assets represent certain amounts receivable from customers in the future and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, Brantford Power Inc. has recorded regulatory liabilities which represent amounts of expenses incurred in different periods than would be the case had the company been unregulated.

Specific regulatory assets and liabilities are disclosed in note 9.

4. Rate Setting - continued

In the absence of rate regulation, distribution revenue would have been lower by $4,144,991 (December 31, 2011 - $3,367,713), cost of power would have been lower by $2,235,587 (December 31, 2011 - $985,277), other income would have been lower by $7,091 (December 31, 2011 - $14,601), distribution operations and maintenance would have been higher by $193,256 (December 31, 2011 - $51,215), general administration would have been higher by $17,195 (December 31, 2011 - $57,877), amortization would have been higher by $321,320 (December 31, 2011 - $315,364), and interest income would have been higher by $5,824 (December 31, 2011 - $48,936). The net effect, in the absence of rate regulation, is a pre-tax decrease in net income for 2012 of $2,442,442 (December 31, 2011 - $2,772,557).

Brantford Power Inc. administers several programs through the Ontario Power Authority (OPA) conservation project. The revenues and expenses related to these programs are not subject to the regulation of the OEB.

On October 21, 2009 Brantford Power Inc. filed an application for 2010 rates on the basis of the OEB's third generation Incentive Regulation Mechanism (IRM) policy which incorporates an OEB-approved formula that considers inflation and efficiency targets. On April 12, 2010, the OEB released its decision. This decision included the repayment of $7,650,132 in regulatory liabilities over a two year period. The revised rates were approved with an effective date of May 1, 2010.

On October 29, 2010 Brantford Power Inc. filed an application for 2011 rates also on the basis of the OEB's third generation IRM policy. On March 28, 2011, the OEB released its decision. This decision included the repayment of $1,192,282 in regulatory liabilities. The revised rates were approved with an effective date of May 1, 2011.

On November 10, 2011 Brantford Power Inc. filed an application for 2012 rates also on the basis of the OEB's third generation IRM policy. On April 19, 2012, the OEB released its decision. This decision included the repayment of $5,841,761 in regulatory liabilities. Included in this total is $2,021,450 in PILs that resulted from the OEB PILs proceeding concluded during 2011. The PILs amount was previously not reflected in the regulatory liabilities total and reduced 2012 distribution revenue in the amount of $1,217,320 as it is returned to the customers. The revised rates were approved with an effective date of May 1, 2012.

Brantford Power Inc. is in the process of preparing a cost of service rate application for 2013 distribution rates.

5. Property, Plant and Equipment

	2012			2011
	Cost	Accumulated Amortization	**Net Book Value**	Net Book Value
	$	$	**$**	$
Land	181,961	-	**181,961**	181,961
Distribution buildings	1,163,732	194,532	**969,200**	992,474
Transformer station	4,507,912	893,531	**3,614,381**	3,727,079
Distribution stations	74,427	30,025	**44,402**	46,883
Distribution lines - overhead	29,840,112	10,814,369	**19,025,743**	18,891,807
Distribution lines - underground	34,084,914	10,386,668	**23,698,246**	22,983,145
Distribution transformers	17,824,165	6,365,512	**11,458,653**	11,682,006
Distribution meters	4,033,045	1,004,368	**3,028,677**	2,973,728
Vehicles	2,928,990	2,132,692	**796,298**	891,003
Computer hardware	103,440	25,860	**77,580**	-
Tools and other equipment	841,329	270,434	**570,895**	591,112
Other utility plant	54,756	-	**54,756**	54,756
Fibre optics	2,934,603	1,171,528	**1,763,075**	1,816,718
Water heater rental units	2,366,915	1,160,715	**1,206,200**	864,416
Generation plant and equipment	8,844,257	1,039,502	**7,804,755**	8,183,970
Landfill gas collection system	3,546,236	416,730	**3,129,506**	3,317,362
Generation building & fixtures	1,214,847	150,146	**1,064,701**	1,125,443
Office furniture and fixtures	53,087	10,601	**42,486**	36,403
Accumulated capital contribution	(4,977,230)	(986,431)	**(3,990,799)**	(3,510,387)
Work in progress - generation	31,455	-	**31,455**	31,455
Work in progress - other	13,086	-	**13,086**	24,008
	109,666,039	35,080,782	**74,585,257**	74,905,342

6. Intangible Assets

	2012			2011
	Cost	Accumulated Amortization	**Net Book Value**	Net Book Value
	$	$	**$**	$
Land rights and easements	94,991	7,748	**87,243**	5,968
Stranded meters	5,381,879	2,215,921	**3,165,958**	3,237,191
Software	635,467	326,271	**309,196**	236,152
	6,112,337	2,549,940	**3,562,397**	3,479,311

7. Restructuring

In December 2011, the City announced plans to restructure the Company to simplify its compliance with the OEB's Affiliate Relationship Code for Electricity Distributors and Transmitters. Effects of the restructuring are detailed below.

The City transferred a total of 55 positions, one effective January 1, 2012 and the remainder on April 1, 2012 impacting 52 permanent and 3 part-time or contract employees.

The transfer of employees resulted in $1,276,000 in post employment benefit obligation including vested sick leave obligation of $163,000 being assumed by Brantford Power Inc. The Company received $198,905 plus interest for the vested sick leave from the City during November 2012.

Brantford Power Inc. also received $1,161,705 plus interest for IT Services Equipment and Customer Service Equipment that had been included in the City's reserves as at March 31, 2012.

The City transferred ownership of certain assets including computer hardware and office furniture effective December 31, 2012. The majority of the assets had a zero net book value with the exception of certain computer hardware related to the customer billing system. The new book value of this hardware was $92,614. The City transferred this over for no cash consideration.

Contributed Surplus

Employee future benefits	**(1,113,000)**
Equipment reserves	**1,161,705**
Computer hardware	**92,614**
Net contributed surplus	**141,319**

8. Related Party Transactions

The Company is wholly owned by The Corporation of the City of Brantford (the City). Transactions between the Company, Brantford Power Inc., Brantford Hydro Inc. and Brantford Generation Inc. occur in the natural course of operations and consideration paid is on similar terms as those to unrelated parties.

The Company has entered into a shared services agreement with the City, whereby the City will provide administrative support, customer care, maintenance and operational services for the Company. The exchange amount for these services has been set out in the agreement. Total charges from the City under this shared agreement were $5,315,333 (December 31, 2011 - $8,822,771). As at December 31, 2012 the balance owing to the City for these services was $1,951,673 (December 31, 2011 - $2,187,578)

For the year ended December 31, 2012, the Company provided electricity to the City in the amount of $5,899,740 (December 31, 2011 - $5,471,768). The Company also provided other services to the City including street light maintenance in the amount of $303,199 (December 31, 2011 - $138,410) and fibre optic services in the amount of $189,251 (December 31, 2011 - $185,749).

For the year ended December 31, 2012, the Company paid property tax to the City in the amount of $16,176 (December 31, 2011 - $16,868)

9. Regulatory Assets and Liabilities

Based on existing regulatory orders or the expectation of future regulatory orders, Brantford Power Inc. has recorded the following amounts, net of income tax and amortization where applicable, which are expected to be recovered from or refunded to customers:

	2012	2011
	$	$
Regulatory Assets		
Retail Market Settlement		
Retail settlement variance account - Global Adjustment	**806,074**	-
Retailer cost variance accounts	**350,993**	339,637
Other		
Smart meters	**3,058,577**	3,048,342
Distribution revenue rate change	**667,068**	527,214
Special purpose charge	**-**	19,478
Lost Revenue Adjustment Mechanism	**95,503**	-
Other regulatory assets	**240,412**	212,657
Net regulatory assets	**5,218,627**	4,147,328
Regulatory liabilities		
Retail Market Settlement		
Retail settlement variance accounts	**3,712,541**	4,265,592
Retail settlement variance account - Global Adjustment	**-**	205,504
Other		
Regulatory future income tax liability	**505,931**	509,205
Regulatory liabilities refundable through approved rate riders	**1,961,610**	2,349,523
Net regulatory liabilities	**6,180,082**	7,329,824

Retail settlement variance accounts

The retail settlement variance accounts represent differences between charges billed to customers using the prescribed prices as outlined in the OEB's Retail Settlement Code and the actual costs billed to Brantford Power Inc. by the IESO.

Retail cost variance accounts

The retailer cost variance accounts represent differences between charges billed to retailers using the prescribed prices as outlined in the OEB's Retail Settlement Code and the actual costs paid by Brantford Power Inc. to operate and maintain the systems related to the retail market.

9. Regulatory Assets and Liabilities - continued

Smart meters

On April 12, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and approved a monthly rate adder charge of $0.28 per metered customer for Brantford Power Inc. Effective May 1, 2009, the OEB increased the monthly adder to $1.00 per metered customer. Effective May 1, 2010, the OEB increased the monthly adder to $2.07 per metered customer. Effective May 1, 2011, the OEB maintained the monthly adder at $2.07 per metered customer. Effective May 1, 2012, the OEB removed the monthly adder.

Brantford Power Inc. has recorded a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder. These expenditures and recoveries will continue to be reported as regulatory assets or liabilities until Brantford Power Inc. applies to the OEB to redistribute the amounts to capital or operations.

Distribution revenue rate change

On February 25, 2009, Brant County Power Inc. (BCPI) filed a motion with the OEB to review and vary Brantford Power Inc.'s 2008 Electricity Distribution Rates. BCPI disputed the rates they were being charged as well as the date that Brantford Power Inc. could bill retroactively. The OEB released its decision and order related to this motion on August 10, 2010. The decision allowed Brantford Power Inc. to record a regulatory asset consisting of the revenue deficiency between the rates that were approved during the 2008 cost of service application for Brantford Power Inc.'s embedded distributor and the rates that were approved as a result of the BCPI motion.

Special purpose charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge (SPC) assessment under Section 26.1 of the OEB Act, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed Brantford Power Inc. the amount of $376,534 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10 (the SPC Regulation). In accordance with Section 9 of the SPC Regulation, Brantford Power Inc. was allowed to recover this balance. The initial recovery was completed as at April 30, 2011. Brantford Power Inc. is recovering the residual balance in this account through rate riders effective May 1, 2012 to April 30, 2013.

9. Regulatory Assets and Liabilities - continued

Lost Revenue Adjustment Mechanism ("LRAM")

On April 26, 2012, the OEB issued The Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-003) approving the creation of an LRAM variance account. The purpose of this account is to track the distribution revenues that are lost as a result of Ontario Power Authority (OPA) conservation programs.

Regulatory future income tax liability

Brantford Power Inc. has recorded a regulatory liability account that relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

Regulatory liabilities refundable through approved rate riders

The regulatory liabilities refundable through approved rate riders consist of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The amount is subject to carrying charges following the OEB prescribed methodology and related rates.

10. Long-Term Debt

	2012 $	2011 $
Notes payable, bearing interest at 5.87%, repayable to the City, interest only payable annually - due February, 2016	**24,189,168**	24,189,168
Notes payable, bearing interest at 6.25%, repayable to the City, interest only payable annually - due February, 2016	**1,303,335**	1,303,335
Royal Bank, non-revolving term facility with interest at prime repayable in quarterly instalments, due January 2018	**3,986,899**	4,361,278
Royal Bank, non-revolving term facility with interest at prime repayable in quarterly instalments, due November 2016	**562,093**	683,657
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest 5.14% repayable in semi annual instalments due December 2032	**2,151,048**	2,212,664
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest 4.95% repayable in semi annual instalments due December 2050	**4,728,626**	4,769,966
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest 3.46% repayable in semi annual instalments due October 2027	**5,564,189**	5,301,704
Ontario Infrastructure and Lands Corporation non-revolving term facility with interest 3.90% repayable in semi annual instalments due December 2042	**3,988,486**	-
Ontario Infrastructure and Lands Corporation construction advances with interest at 1.60% (2011 - 1.75%)	**12,751,806**	12,951,683
	59,225,650	55,773,455
Less current portion	**991,134**	598,986
	58,234,516	55,174,469

The City has an option to extend the maturity date of the promissory notes for successive five year periods. The City also has the option to convert the principal sums outstanding into common shares of the Company at a conversion ratio of $ 100 per common share. Interest payable to the City of $1,501,362 (December 31, 2011 - $1,509,022) was outstanding as at December 31, 2012.

10. Long-Term Debt - continued

The Company entered into a swap agreement during 2006 with Royal Bank to hedge against exposure to interest rate fluctuations. The agreement represents a notional principal amount of $ 5,900,000. Under the terms of the agreement, the company has contracted to pay interest at a fixed rate of 4.71% while receiving a variable rate equivalent to the one month Canadian Dollar Offered Rate to be repriced quarterly.

The Company entered into a second swap agreement during 2006 with Royal Bank to hedge against exposure to interest rate fluctuations. The agreement represents a notional principal amount of $ 1,200,000. Under the terms of the agreement, the company has contracted to pay interest at a fixed rate of 4.97% while receiving a variable rate equivalent to the one month Canadian Dollar Offered Rate to be repriced quarterly.

The Company entered into a financing agreement with the Ontario Infrastructure and Lands Corporation (OILC) to advance funds for the construction of the LFG facilities. The financing agreement for the LFG facilities has approved funds up to $14,000,000 excluding accrued interest. Interest was being accrued monthly at rates set monthly by the OILC. Effective June 1, 2011, the Company is required to pay interest expense as it is incurred. As of December 31, 2012 advances of $12,437,659 (2011 $12,637,659) have been received and interest has been accrued in the amount of $314,146 (2011 $314,024). In 2013, the outstanding construction loan balance is expected to be converted to a debenture with a term of 20 years.

These credit facilities are secured by general security agreement over all assets of the Company and an assignment of related fire insurance.

Estimated principal repayment requirements are as follows:

	$
2013	991,134
2014	1,038,479
2015	1,088,567
2016	25,330,598
2017	1,034,099
Thereafter	29,742,773

11. Employee Future Benefits

Brantford Power Inc. acquired various life insurance, health care related and dental coverage plan liabilities for certain retired employees of the former Hydro-Electric Commission of the City of Brantford. Travel, dental, vision and semi-private health care coverage is continued until the retiree reaches 65 years of age. Life insurance and extended health care coverage is continued until the retiree's death. Brantford Power Inc. is also obligated to provide post retirement benefits to active employees.

11. Employee Future Benefits - continued

Brantford Power Inc. measures the accrued benefit obligation for accounting purposes as of December 31 of each year. The accrued benefit obligation as at December 31, 2012 and the expense for the year ended December 31, 2012 are based on actuarial valuations done as at January 1, 2012 and April 1, 2012.

The obligation is unfunded since no assets have been segregated and restricted to provide the post-retirement benefits.

Significant Assumptions

The key weighted-average assumptions used by Brantford Power Inc. for the measurement of the benefit obligation and benefit expense are summarized as follows:

	2012	2011
	$	$
To determine benefit obligation at end of year		
Discount rate	**3.50%**	3.25%
Assumed long-term rate of return on assets	**N/A**	N/A
To determine benefit expense (income) for the year		-
Discount rate	**3.25%**	4.5%
Assumed long-term rate of return on assets	**N/A**	N/A
Rate of increase in future compensation	**N/A**	N/A
Health care cost trend rates at end of year		
Initial rate	**9.00%**	6.45%
Ultimate rate	**5.00%**	4.75%
Year ultimate rate reached	**2019**	2013

Sensitivity Analysis	**Change in Obligation**	**Change in Expense**
	$	$
Impact of 1% increase in assumed health care trend rate	127,178	20,341
Impact of 1% decrease in assumed health care trend rate	(107,822)	(16,815)

11. Employee Future Benefits - continued

	2012	2011
	$	$
Change in benefit obligation		
Benefit obligation at beginning of year	**1,684,720**	1,734,220
Opening benefit obligation adjustment to reflect full valuation versus extrapolation	**(758,258)**	-
Obligation assumed on transferred employees	**1,113,000**	-
Accrual for service	**73,635**	-
Interest cost on benefit obligation	**59,043**	77,863
Benefits paid	**(25,100)**	(58,616)
Actuarial (gain) loss on accrued benefit obligation	**(422,878)**	(68,747)
Benefit obligation at end of year	**1,724,162**	1,684,720
Change in fair value of assets		
Fair value of assets at beginning of year	**-**	-
Employer contributions	**25,100**	58,616
Benefits paid	**(25,100)**	(58,616)
Fair value of assets at end of year	**-**	-
Reconciliation of funded status to accrued benefit liability		
Deficit of fair value of assets over benefit obligation at end of year	**1,724,162**	1,684,720
Unamortized actuarial loss/(gain)	**395,054**	(786,653)
Accrued benefit liability at end of year	**2,119,216**	898,067
Reconciliation of accrued benefit liability		
Accrued benefit liability at beginning of year	**898,067**	817,515
Liability assumed on transferred employees	**1,113,000**	-
Benefit expense recognized	**132,678**	139,168
Benefits paid	**(25,100)**	(58,616)
Other	**571**	-
Accrued benefit liability at end of year	**2,119,216**	898,067
Annual benefit expense		
Interest cost on benefit obligation	**59,043**	77,863
Accrual for services	**73,635**	-
Actuarial loss	**-**	61,305
Benefit expense recognized	**132,678**	139,168

11. Employee Future Benefits - continued

Cash payments		-
Benefit premiums paid	**109,454**	91,633

12. Vested Sick Leave

Brantford Power Inc. is obligated to pay certain employees their sick leave banks that were frozen on December 31, 1998 by the former Hydro-Electric Commission of the City of Brantford. The sick leave banks will be paid out at retirement at the employee's pay rate at time of retirement.

13. Contingencies and Commitments

General Liability Insurance

The Company has obtained general liability and enhanced directors and officers insurance coverage from the Municipal Electric Association Reciprocal Insurance Exchange (The Mearie Group) expiring January 1, 2014. The Mearie Group is an insurance reciprocal whereby all members through the unincorporated group share risks with each other. Members of the Mearie Group are assessed a premium deposit at policy execution. Should the group experience losses that are in excess of the accumulated premium deposits of its members combined with reserves and supplementary insurance, members would be assessed a supplementary or retro assessment on a pro-rata basis for the years in which the Company was a member.

As at December 31, 2012, the Company has not been made aware of any additional assessments. Participation in The Mearie Group covers a three year underwriting period which expires on January 1, 2016.

Smart Meter Initiative

The OEB has mandated that the Company is to bill Time of Use Prices using "Smart Meter" electricity meters and the Provincial Meter Data Management/Respository effective July 2011. The Company was granted an extension of the effective date to December 2011.

The Company has installed approximately 37,185 (December 31, 2011 - 37,134) Smart Meters as of the end of 2012 and anticipates having installed a total of 37,240 Smart Meters upon completion of its mass deployment.

14. Contractual Obligations

The Company has contracted Wajax Power Systems (Wajax) to design and build the LFG facilities for a fixed amount of $13,193,446. In addition, the contract provides for Wajax to provide operation and maintenance services for a period of ten years beginning with the commercial operations of the facilities. The Company also has an option to extend the term of these services for an additional ten years.

The Company has also entered into an agreement with the City allowing the Company access to the Mohawk Street landfill to install, operate and maintain a landfill gas collection and utilization system. This agreement expires August 22, 2030.

15. Share Capital

Authorized
Unlimited number of common shares

	2012	2011
	$	$
Issued		
2,001 common shares	**23,895,512**	23,895,512

16. Accumulated Other Comprehensive Loss

	2012	2011
	$	$
Balance at beginning of year	**(518,279)**	(374,658)
Other comprehensive income/(loss), net of tax	**125,113**	(143,621)
Balance at end of year	**(393,166)**	(518,279)

17. Pension Plan

The Company participates in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer plan, on behalf of its employees. The plan is a contributory defined benefit pension plan. Contributions are 8.3% for employee earnings below the year's maximum pensionable earnings and 12.8% thereafter. The contribution rates changed to 9.0% for employee earnings below the year's maximum pensionable earnings and 14.6% thereafter for 2013. During 2012, the Company expensed contributions totaling $287,566 (December 31, 2011 - $24,518) made to OMERS in respect of the employer's required contributions to the plan.

18. Electricity Distribution Service Charges

The company is licensed by the OEB to distribute electricity. As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company may file to recover uncollected debt retirement charges from OEFC once each year. Otherwise, the Company is unable to recover uncollected amounts formerly remitted to these third parties. The Company retains only its electricity distribution service charge that is regulated by the OEB.

Electricity distribution service charges comprise:

	2012	2011
	$	$
Gross customer billings	**111,713,232**	105,109,712
Less: Pass through charges billed by the Company		
Electricity charges paid through to generators	**(73,268,847)**	(66,724,020)
Transmission and miscellaneous charges	**(11,354,826)**	(10,618,115)
Market service charges	**(6,200,632)**	(6,186,857)
Debt retirement charges	**(6,551,933)**	(6,422,286)
Total electricity distribution service charges	**14,336,994**	15,158,434

19. Statement of Cash Flows

	2012	2011
	$	$
Changes in non-cash working capital		
Accounts receivable	**(1,563,157)**	1,133,817
Unbilled revenue	**74,033**	358,062
Inventories	**(385,694)**	100,711
Prepaid expenses	**9,508**	37,369
Accounts payable and accrued liabilities	**2,206,221**	(1,035,791)
Accounts payable to the City of Brantford	**(235,905)**	20,939
Interest payable to the City of Brantford	**(7,660)**	(84,259)
Payments in lieu of corporate income taxes	**788,488**	(1,013,332)
	885,834	(482,484)

20. Amortization

	2012	2011
	$	$
Amortization of capital assets	**4,612,187**	4,802,671
Amortization of capital assets charged to operations and capital	**218,541**	271,416
	4,830,728	5,074,087

21. Capital Disclosures

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to meet any capital needs should needs arise;
- ensure compliance with covenants related to its credit facilities; and
- closely align its capital structure with the debt to equity structure deemed by the OEB.

As at December 31, 2012, the Company's definition of capital includes shareholder's equity and long-term debt. This definition remains unchanged from prior years. As at December 31, 2012, shareholder's equity amounts to $37,510,632 (December 31, 2011 - $36,253,735) and long-term debt, amounts to $59,225,650 (December 31, 2011 - $55,773,455). The Company's capital structure as at December 31, 2012 is 61% debt and 39% equity (December 31, 2011 - 61% debt and 39% equity). There have been no changes in the Company's approach to capital management during the year.

The Company's long-term debt agreements include both financial and non-financial covenants. As at December 31, 2012 and as at December 31, 2011, the Company was in compliance with all covenants.

22. Financial Instruments and Risk Management

All financial instruments are initially recorded on the balance sheet at fair value except for certain related party transactions. They are subsequently valued either at fair value or amortized cost depending on the classification selected by the Company for the financial instrument. All financial instruments are classified into one of the five categories: held-for-trading, loans and receivables, other liabilities, held-to-maturity investments or available-for-sale financial assets.

22. Financial Instruments and Risk Management - continued

Held-for-trading (HFT) financial instruments are financial assets and financial liabilities typically acquired with the objective of resale or short-term buyback. The carrying amount is recorded at fair value determined using market prices. Interest earned and gains and losses incurred are recognized in net income. Cash and cash equivalents and special deposits are designated as financial assets held-for-trading and are measured at fair value with changes being recorded in net income at each period end. Derivative liabilities are designated as financial liabilities held-for-trading and are measured at fair value with changes being recorded in other comprehensive income at each period end.

Loans and receivables (LR) are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date, or on demand, usually with interest. Loans and receivables are measured at amortized cost. Accounts receivable and unbilled revenue are classified as loans and receivables and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost.

Other liabilities (OL) are promises to repay on specified dates or on demand usually with interest. Accounts payable and accrued liabilities and accounts payable to the City of Brantford, interest payable to the City of Brantford and due to affiliates are classified as other liabilities and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost. Long-term debt and customer deposits are also classified as other liabilities. After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

Held-to-maturity (HTM) financial assets have fixed or determinable payments and maturity, and management’s intention and ability are to hold to maturity. These financial assets are measured at amortized cost. The Company does not hold any financial assets under this classification.

Available-for-sale (AFS) instruments are non-derivative financial assets that are designated as available-for-sale or that are not classified as loans and receivables, held-to-maturity investments or held-for-trading financial assets. Available-for-sale instruments are measured at fair value with unrealized gains and losses recognized in OCI. The Company does not hold any financial assets under this classification.

22. Financial Instruments and Risk Management - continued

Interest Rate Risk

Interest is paid on electricity customer deposits at a market rate reset quarterly as directed by the Ontario Energy Board.

Two term facility loans bear interest at floating rates and thus, the carrying values approximate fair values. However, the Company has entered into two interest rate swap transactions, derivative instruments designated as a cash flow hedges, the effect of which is to fix the interest rate on the first $3,994,000 term facility loan at 4.71% and the second $564,000 term facility loan at 4.97%. The potential replacement cost to Brantford Power Inc. of the interest rate swaps, representing estimated fair value as presented on the balance sheet, was $554,860 (December 31, 2011 -$713,683), which was in the favour of Royal Bank. Net unrealized gain in fair value of $156,203 (December 31, 2011 - loss of $191,491) is presented in current year Other Comprehensive Income/(Loss). The Company entered into these interest rate swap transactions to fix the interest rates over the long term and intends to hold these to maturity at which time there should be no replacement cost.

Credit Risk

The Company grants credit to its customers in the normal course of business and monitors their financial condition and reviews the credit history of new customers. The Company is currently holding customer deposits on hand in the amount of $1,897,660 (December 31, 2011 - $2,112,132) which is reflected on the Balance Sheet. Customer deposits are limited to those allowed under the OEB's Retail Settlement Code. Allowances of $699,000 (December 31, 2011 - $695,000) are also maintained for potential credit losses. Management believes that it has adequately provided for any exposure to normal customer and retailer credit risk.

Liquidity Risk

The Company's objective is to have sufficient liquidity to meet its liabilities when due. The Company monitors its cash balances and cash flows generated from operations to meet its requirements.

22. Financial Instruments and Risk Management - continued

Prudential Support

Brantford Power Inc. is required, through the Independent Electricity System Operator (IESO), to provide security to mitigate the company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if the Company fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letter of credit. As at December 31, 2012, the Company provided prudential support in the form of a bank letter of credit of $13,057,140 (December 31, 2011 - $9,375,721).

Revolving Term Facility

As at December 31, 2012, the Company has been authorized for a revolving term facility of $7,200,000 of which NIL had been drawn upon. The facility bears interest at prime and is secured by a general security agreement over all assets of the Company and assignment of related fire insurance.

Non-Revolving Term Facility

As at December 31, 2012, the Company has been authorized for a non-revolving term facility of $600,000 of which NIL had been drawn upon. The facility bears interest at prime and is secured by a general security agreement over all assets of the Company, and an assignment of related fire insurance.

Fair Value of Other Financial Instruments

a) Establishing fair value

The carrying values of cash and cash equivalents, accounts receivable, special deposits, accounts payable and accrued liabilities, accounts payable to the City of Brantford, and interest payable to the City of Brantford approximate their fair values due to the immediate or short-term maturity of these financial instruments.

Fair values for other financial instruments, detailed below, have been estimated with reference to quoted market prices for actual or similar instruments where available, except for certain related party transactions.

Customer deposits fair value equals carrying value. Interest is paid on deposits on a monthly basis at a market rate, reset quarterly, as directed by the Ontario Energy Board.

22. Financial Instruments and Risk Management - continued

The fixed rate long-term debt facility, maturing December 2032, funded by Ontario Infrastructure and Lands Corporation (OILC) has an estimated fair value of $2,448,900 (carrying value - $2,151,048). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 3.80% per annum, (actual rate – 5.14% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

The fixed rate long-term debt facility, maturing December 2050, funded by the OILC has an estimated fair value of $5,382,500 (carrying value - $4,728,626). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 4.00% per annum, (actual rate – 4.95% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

The fixed rate long-term debt facility, maturing October 2027, funded by the OILC has an estimated fair value of $5,581,600 (carrying value - $5,564,189). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 3.33% per annum, (actual rate - 3.46% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

The fixed rate long-term debt facility, maturing December 2042, funded by the OILC has an estimated fair value of $4,000,000 (carrying value - $3,988,486). The fair value was determined using the present value of the cash flows using the quoted OILC market rate for the debt at December 31, 2012, of 3.90% per annum, (actual rate - 3.90% per annum). The loan is classified as an Other Liability (OL) with no resulting adjustment to carrying value.

Construction advances funded by the OILC, classified as OL are valued at face value. In 2013 the outstanding construction loan balance is expected to be converted to a debenture with a term of 20 years.

The promissory notes payable to the Corporation of the City of Brantford, classified as an Other Liability (OL), are valued at face value. It is not practicable within constraints of timeliness or cost to measure reliably the fair value of these financial liabilities that originated in a related party transaction.

The fair value of derivative instruments is calculated using pricing models that incorporate current market prices and the contractual prices of the underlying instruments, the time value of money and yield curves.

b) Fair value hierarchy

Financial instruments recorded at fair value on the Balance Sheet are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

22. Financial Instruments and Risk Management - continued

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (ie as prices) or indirectly (ie derived from prices);

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

The following table presents the financial instruments recorded at fair value in the Balance Sheet, classified using the fair value hierarchy described above:

	Level 1	Level 2	Level 3	Total financial assets and liabilities at fair value
	$	**$**	**$**	$
Financial Assets				
Cash and cash equivalents	16,441,207	-	-	16,441,207
Special deposits	1,860,225	-	-	1,860,225
Total financial assets	**18,301,432**	**-**	**-**	**18,301,432**
Financial liabilities				
Customer deposits	1,897,660	-	-	1,897,660
Total financial liabilities	**1,897,660**	**-**	**-**	**1,897,660**

During the year, there has been no transfer of amounts between Level 1 and Level 2 and no financial assets or liabilities have been identified as Level 3.

23. Payments in Lieu of Corporate Income Taxes

The Company's income tax expense for the year ended December 31, 2012 consists of the following:

Temporary differences and carryforwards which give rise to future income tax assets and liabilities are as follows:

	2012	2011
	$	$
Regulatory assets	**322,953**	643,641
Unrealized losses on derivative liabilities	**140,530**	171,620
Cumulative eligible capital	**170,550**	157,080
Employee future benefits	**594,940**	244,390
Allowance for doubtful accounts	**185,235**	182,438
Property, plant and equipment	**(1,584,165)**	(850,395)
Tax loss carry forward	**2,463,100**	2,150,156
Future income tax assets	**2,293,143**	2,698,930

Distributed as such:		
Future payments in lieu of corporate income tax asset		
Current	**185,235**	182,438
Non-current	**2,107,908**	2,516,492
	2,293,143	2,698,930

23. Payments in Lieu of Corporate Income Taxes - continued

The impact of differences between the Company's reported payments in lieu of corporate income taxes and the expense that would otherwise result from the application of statutory rates is as follows:

	2012	2011
	$	$
Income tax expense at the combined basis federal and provincial statutory tax rate	**732,817**	1,195,128
Impact of change in rates	**26,803**	97,276
Scientific Research and Educational Development tax credits	**-**	(65,453)
Capital cost allowance in excess of amortization	**(82,629)**	1,803,228
Net change in tax reserves	**280,656**	(95,268)
Provision relating to prior periods	**121,889**	(21,890)
Tax effect of expenses that are not deductible for income tax purposes	**3,317**	1,056
Small business deduction	**(30,581)**	(36,250)
Tax effect of loss carry forwards	**(312,944)**	(1,950,857)
Other items	**-**	(805)
	739,328	926,165

24. Comparative Figures

Certain prior year figures have been reclassified to conform with the current year's presentation.

Brantford Energy Corporation
Consolidated Schedule of Segmented Reporting
for the year ended December 31, 2012

	Distribution	Rental and Fibre Optics	Generation	Other	**Consolidated**
2012 Segment Profit	$	$	$	$	**$**
Revenues	19,293,108	2,694,103	2,141,161	1,128	**24,129,500**
Expenses					
Operations and maintenance	3,389,490	991,733	720,718	-	**5,101,941**
Billing and collection	1,870,898	-	-	-	**1,870,898**
General administration	2,441,957	428,138	197,622	292,266	**3,359,983**
Ontario Power Authority	3,683,840	-	-	-	**3,683,840**
Interest on long-term debt	2,163,585	81,458	202,921	-	**2,447,964**
Other financing expenses	172,775	-	-	-	**172,775**
Capital tax	-	-	-	119	**119**
Amortization	3,595,408	332,350	684,429	-	**4,612,187**
	17,317,953	1,833,679	1,805,690	292,385	**21,249,707**
Income before payments in lieu of corporate income taxes	1,975,155	860,424	335,471	(291,257)	**2,879,793**
Capital expenditures	3,966,485	646,851	(9,886)	-	**4,603,450**
2011 Segment Profit	$	$	$	$	$
Revenues	16,919,050	2,534,788	1,645,306	2,002	21,101,146
Expenses					
Operations and maintenance	2,954,060	827,869	510,809	-	4,292,738
Billing and collection	1,921,628	53,841	-	-	1,975,469
General administration	1,944,350	345,365	191,226	253,673	2,734,614
Ontario Power Authority	735,093	-	-	-	735,093
Interest on long-term debt	2,159,034	81,458	200,221	-	2,440,713
Other financing expenses	195,748	-	-	-	195,748
Capital tax	(1,318)	(52)	(450)	64	(1,756)
Amortization	3,842,300	292,660	667,711	-	4,802,671
	13,750,895	1,601,141	1,569,517	253,737	17,175,290
Income before payments in lieu of corporate income taxes	3,168,155	933,647	75,789	(251,735)	3,925,856
Capital expenditures	4,611,584	437,297	647,689	-	5,696,570

	2012	2011
Total assets by segment	**$**	$
Distribution	**105,969,513**	99,412,210
Generation	**13,516,179**	13,654,445
Rental and fibre optics	**4,120,739**	4,010,166
Other	**32,810**	53,318
	123,639,241	117,130,139

Non-Consolidated Financial Statements of

Brantford Energy Corporation

December 31, 2012

Brantford Energy Corporation
Table of Contents
December 31, 2012

Brantford Energy Corporation

Management Report

December 31, 2012

The accompanying non-consolidated financial statements are the responsibility of management of Brantford Energy Corporation (the Company). In management's opinion, these non-consolidated financial statements prepared by management, which have not been, and were not intended to be, prepared in accordance with Canadian generally accepted accounting principles are solely for the information and use of the board of directors of the Company and the provincial corporate tax authorities for corporate tax purposes. Management has selected accounting principles and methods that are appropriate to the Company's circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. The notes to the financial statements and any other supplementary information presented are consistent with that in the financial statements.

The Company maintains systems of internal accounting and administrative controls that are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, that transactions are properly authorized and that the Company's assets are properly accounted for and adequately safeguarded.

The non-consolidated financial statements have been examined by Deloitte LLP, the external auditors of the Company. The responsibility of the external auditors is to express their opinion on whether the non-consolidated financial statements are fairly presented, in all material respects, in accordance with the basis of accounting described in note 2 to the non-consolidated financial statements.

The board of directors, through the finance committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The finance committee meets periodically with management, as well with the external auditors to satisfy itself that each party is properly discharging its responsibilities with respect to internal controls and financial reporting. The finance committee also reviews the financial statements and annual report and recommends their approval to the board of directors. Deloitte LLP has full and free access to the finance committee, with and without the presence of management.

Ted Salisbury	Catherine Barker-Hoyes, CGA
Chief Executive Officer	Chief Financial Officer
April 30, 2013	April 30, 2013

Deloitte LLP
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Suite 200
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Independent Auditor's Report

To the Board of Directors of
Brantford Energy Corporation

We have audited the accompanying non-consolidated financial statements of Brantford Energy Corporation, which comprise the non-consolidated balance sheet as at December 31, 2012, and the non-consolidated statements of retained earnings, operations and comprehensive income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting described in Note 2 of the non-consolidated financial statements.

Management's Responsibility for the Non-Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these non-consolidated financial statements in accordance with the basis of accounting described in Note 2 of the non-consolidated financial statements, and for such internal control as management determines is necessary to enable the preparation of non-consolidated 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 non-consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the non-consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the non-consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the non-consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the non-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 non-consolidated financial statements.

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

Opinion

In our opinion the non-consolidated financial statements present fairly, in all material respects, the financial position of Brantford Energy Corporation as at December 31, 2012 and the results of its operations and its cash flows for the year then ended in accordance with the basis of accounting described in Note 2 of the non-consolidated financial statements.

Basis of Accounting and Restriction on Distribution and Use

Without modifying our opinion, we draw attention to Note 2 to the financial statements, which describe the basis of accounting. The financial statements are prepared to assist Brantford Energy Corporation to meet the requirements of their shareholder. As a result, the financial statements may not be suitable for another purpose. Our report is intended solely for the shareholder of Brantford Energy Corporation and should not be distributed or used by parties other than the shareholder of Brantford Energy Corporation.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Licensed Public Accountants
May 2, 2013

Brantford Energy Corporation
Non-Consolidated Balance Sheet
as at December 31, 2012

Assets	**2012**	2011
	$	$
Current Assets		
Cash and cash equivalents	**23,708**	46,149
Accounts receivable	**5,544**	2,492
Due from subsidiaries - note 4	**166,048**	67,372
Prepaid expenses	**1,117**	1,117
	196,417	117,130
Long-Term Prepaid Expenses	**2,443**	3,560
Investment in Subsidiaries - note 5	**23,825,511**	23,825,511
	24,024,371	23,946,201

Liabilities and Shareholder's Equity

Current Liabilities		
Accounts payable and accrued liabilities	**13,743**	10,704
Accounts payable to the City of Brantford - note 6	**115,116**	39,985
	128,859	50,689
Contingent Liabilities - note 7		
Shareholder's Equity		
Share capital - note 8	**23,895,512**	23,895,512
	24,024,371	23,946,201

Signed on behalf of the Board:

______________________________ Director

______________________________ Director

Brantford Energy Corporation
Non-Consolidated Statement of Retained Earnings
for the year ended December 31, 2012

	2012	2011
	$	$
Retained Earnings, Beginning of Year	**-**	-
Net Income	**1,150,000**	1,800,000
Dividends	**(1,150,000)**	(1,800,000)
Retained Earnings, End of Year	**-**	-

Brantford Energy Corporation

Non-Consolidated Statement of Operations and Comprehensive Income
for the year ended December 31, 2012

	2012	2011
	$	$
Revenue		
Dividend income	**1,150,000**	1,800,000
Management fees - note 6	**291,257**	251,735
Interest income	**1,129**	2,002
Other income	**-**	-
	1,442,386	2,053,737
Expenses		
General administration	**292,267**	253,673
Capital tax	**119**	64
	292,386	253,737
Net Income	**1,150,000**	1,800,000
Comprehensive Income	**-**	-
Net Income and Comprehensive Income	**1,150,000**	1,800,000

Brantford Energy Corporation
Non-Consolidated Statement of Cash Flows
for the year ended December 31, 2012

	2012	2011
	$	$
Operating activities		
Net income and comprehensive income	**1,150,000**	1,800,000
Changes in non-cash working capital components - note 9	**(22,441)**	12,551
	1,127,559	1,812,551
Financing activity		
Dividends paid	**(1,150,000)**	(1,800,000)
	(1,150,000)	(1,800,000)
Increase (decrease) in cash and cash equivalents	**(22,441)**	12,551
Cash and cash equivalents, beginning of year	**46,149**	33,598
Cash and cash equivalents, end of year	**23,708**	46,149
Supplemental disclosure of cash flows		
Interest received	**1,203**	2,026
Payments in lieu of corporate income taxes paid	**119**	64

1. Incorporation

On March 1, 2000, Brantford Energy Corporation (the Company) was incorporated under the Business Corporations Act (Ontario) along with its wholly-owned subsidiary companies, Brantford Hydro Inc. and Brantford Power Inc. A third wholly-owned subsidiary company, Brantford Generation Inc., was incorporated in 2007. The Company is wholly owned by The Corporation of the City of Brantford. The incorporations were pursuant to the provisions of the Energy Competition Act, 1998.

The principal business of the Company is to oversee the operations of Brantford Power Inc., providing regulated electricity distribution services, Brantford Hydro Inc., providing fibre optics networks, water heater rental, sentinel lighting and other equipment rental services and Brantford Generation Inc., providing electricity generation.

2. Accounting Policies

Basis of accounting

The financial statements of the Company have been prepared in accordance with the significant accounting policies set out below. These financial statements materially differ from Canadian generally accepted accounting principles (GAAP) because they are non-consolidated. The Company's investment in its subsidiary companies has been recorded at cost. Earnings from the investments are recognized only to the extent dividends are received or receivable. For a more informative presentation of the financial statements of the Company, reference should be made to the consolidated financial statements for the same period.

Payments in lieu of corporate income taxes

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes (PILS) to the Ontario Electricity Financial Corporation (OEFC), beginning October 1, 2001. These payments are recorded in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) and modified by the *Electricity Act, 1998*, and related regulations. The Company accounts for PILS using the liability method.

2. Accounting Policies - continued

Use of estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure and contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the year. Management made only one significant estimate related to the annual audit fee accrual. Estimates are based on historical experience, current trends and various other assumptions that are believed to be reasonable under the circumstance. Actual results could differ from estimates.

Investments

The Company's investments in Brantford Power Inc., Brantford Hydro Inc. and Brantford Generation Inc., of which it owns 100% of the outstanding voting shares for all, are recorded at cost.

Cash and cash equivalents

Cash and cash equivalents include cash and short-term investments with maturities of three months or less from the date of acquisition.

Impairment of long-lived assets

The Company reviews the valuation of long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. There was no impact on the financial statements as a result of asset impairments for the years ended December 31, 2012 and December 31, 2011.

2. Accounting Policies - continued

Financial Instruments

The Corporation designates its financial instruments in one of the following five categories: (i) held for trading (HFT); (ii) available for sale (AFS); (iii) held to maturity (HTM); (iv) loans and receivables (LR); or (v) other liabilities (OL). All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value, with any change in fair value recognized in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

The Company has elected to add transaction costs related to financial instruments classified as other than HFT to the carrying amount of the financial instrument.

The Company has elected to use settlement-date accounting for regular-way purchases and sales of financial assets.

Long-term prepaid expenses

Long-term prepaid expenses consist of service fees paid providing the Company with the right to use non-owned specified tangible assets for future periods. These charges are amortized on a straight-line basis over 10 years.

Revenue recognition

Revenue is recorded in the period to which it relates and collection is reasonably assured. Dividend income is recorded in the period in which the dividend is declared.

3. Future Changes in Accounting Framework

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP effective January 1, 2011. The Company has decided to issue special purpose financial statements for its year ended December 31, 2012 under Canadian GAAP which will allow for a deferral in the adoption of IFRS. This deferral will coincide with the 2012 deferral elected by its rate-regulated affiliate.

The Company is continuing to assess the financial reporting impacts of the adoption of IFRS on its non-consolidated financial statements. At this time, the Company's future financial position and results of operations are not expected to be significantly impacted. The Company does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required.

4. Due From Subsidiaries

	2012	2011
	$	$
Brantford Power Inc.	**53,630**	23,312
Brantford Hydro Inc.	**17,877**	7,771
Brantford Generation Inc.	**94,541**	36,289
	166,048	67,372

5. Investment in Subsidiaries

	2012	2011
	$	$
Brantford Power Inc., 1,001 common shares (100%)	**22,437,505**	22,437,505
Brantford Hydro Inc., 1,001 common shares (100%)	**1,338,006**	1,338,006
Brantford Generation Inc., 1,001 common shares (100%)	**50,000**	50,000
	23,825,511	23,825,511

6. Related Party Transactions

The Company is a wholly owned by The Corporation of the City of Brantford (the City). Transactions between the Company, Brantford Power Inc., Brantford Hydro Inc. and Brantford Generation Inc. occur in the natural course operations and consideration paid is on similar terms as those to unrelated parties.

The Company has entered into a shared services agreement with the City, whereby the City will provide administrative support for the Company. The exchange amount for these services has been set out in the agreement. Total charges from the City under this shared agreement were $252,423 (December 31, 2011 - $229,986).

During the year, Brantford Energy Corporation charged a fee for management services to its subsidiaries in the following amounts:

	2012	2011
	$	$
Brantford Power Inc.	**174,755**	151,041
Brantford Hydro Inc.	**58,251**	50,347
Brantford Generation Inc.	**58,251**	50,347
	291,257	251,735

7. Contingent Liabilities

General Liability Insurance

The Company has obtained general liability and enhanced directors and officers insurance coverage from the Municipal Electric Association Reciprocal Insurance Exchange ("The Mearie Group") expiring January 1, 2014. The Mearie Group is an insurance reciprocal whereby all members through the unincorporated group share risks with each other. Members of the Mearie Group are assessed a premium deposit at policy execution. Should the group experience losses that are in excess of the accumulated premium deposits of its members combined with reserves and supplementary insurance, members would be assessed a supplementary or retro assessment on a pro-rata basis for the years in which the Company was a member.

As at December 31, 2012, the Company has not been made aware of any additional assessments. Participation in The Mearie Group covers a three year underwriting period which expires on January 1, 2016.

8. Share Capital

Authorized
Unlimited number of common shares

	2012	2011
	$	$
Issued		
2001 common shares	**23,895,512**	23,895,512

9. Statement of Cash Flows

	2012	2011
	$	$
Changes in non-cash working capital components		
Accounts receivable	**(3,052)**	2,294
Due from subsidiaries	**(98,676)**	8,414
Prepaid expenses	**1,117**	1,117
Accounts payable and accrued liabilities	**3,039**	1,851
Accounts payable to the City of Brantford	**75,131**	(1,125)
	(22,441)	12,551

10. Capital Disclosures

The Company's objectives with respect to its capital structure are to retain 100% equity capitalization and to deliver the appropriate returns achieved from its subsidiaries.

11. Financial Instruments and Risk Management

All financial instruments are initially recorded on the balance sheet at fair value except for certain related party transactions. They are subsequently valued either at fair value or amortized cost depending on the classification selected by the Company for the financial instrument. All financial instruments are classified into one of the five categories: held-for-trading, loans and receivables, other liabilities, held-to-maturity investments or available-for-sale financial assets

Held-for-trading (HFT) financial instruments are financial assets and financial liabilities typically acquired with the objective of resale or short-term buyback. The carrying amount is recorded at fair value determined using market prices. Interest earned and gains and losses incurred are recognized in net income. Cash and cash equivalents are designated as financial assets held for-trading and are measured at fair value with changes being recorded in net income at each period end.

11. Financial Instrument and Risk Management - continued

Loans and receivables (LR) are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date, or on demand, usually with interest. Loans and receivables are measured at amortized cost. Accounts receivables and due from subsidiaries are classified as loans and receivables and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost.

Other liabilities (OL) are promises to repay on specified dates or on demand usually with interest. Accounts payable and accounts payable to the City of Brantford classified as other liabilities and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost.

Held-to-maturity (HTM) financial assets have fixed or determinable payments and maturity, and management's intention and ability are to hold to maturity. These financial assets are measured at amortized cost. The Company does not hold any financial assets under this classification.

Available-for-sale (AFS) instruments are non-derivative financial assets that are designated as available-for-sale or that are not classified as loans and receivables, held-to-maturity investments or held-for-trading financial assets. Available-for-sale instruments are measured at fair value with unrealized gains and losses recognized in other comprehensive income. The Company does not hold any financial assets under this classification.

The Company, through its financial assets and liabilities has exposure to liquidity risk from its use of financial instruments. The following analysis provides a measurement as at December 31, 2012:

Liquidity Risk

The Company's objective is to have sufficient liquidity to meet its liabilities when due. The Company monitors its cash balances and cashflows generated from operations to meet its requirements.

Fair Values

a) Establishing fair value

The fair values of cash and cash equivalents, accounts receivable, due from subsidiaries, accounts payable and accrued liabilities, and accounts payable to the City of Brantford approximate their carrying values due to the relatively short periods to maturity of the instruments.

11. Financial Instrument and Risk Management - continued

b) Fair value hierarchy

Financial instruments recorded at fair value on the Balance Sheet are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (ie as prices) or indirectly (ie derived from prices);

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

The following table presents the financial instruments recorded at fair value in the Balance Sheet, classified using the fair value hierarchy described above:

	Level 1	Level 2	Level 3	Total financial assets and liabilities at fair value
	$	**$**	**$**	$
Financial Assets				
Cash and cash equivalents	23,708	-	-	23,708
Total financial assets	**23,708**	**-**	**-**	**23,708**

During the year, there has been no transfer of amounts between Level 1 and Level 2 and no financial assets or liabilities have been identified as Level 3.

ATTACHMENT E

REFERENCE: 1.0 Energy Probe-7b

BRANTFORD ENERGY CORPORATION
415 Mohawk Street
Brantford, Ontario
N3T 5L9
(226) 493-1043

THE ENERGY BEHIND BRANTFORD

BRANTFORD ENERGY CORPORATION
2012 ANNUAL REPORT

BRANTFORD ENERGY CORPORATION

We provide leadership, guidance and communication links to the corporate family to assist them in developing and fulfilling their mandates pursuant to the Shareholder's Declaration and we facilitate liaison with other corporate stakeholders.

TABLE OF CONTENTS

Jim Ryan
Chair, Brantford Energy Corp.

BRANTFORD ENERGY

Managing a year of transition

The Brantford Energy family of companies has successfully navigated through an eventful year of transition, thanks primarily to the dedication and drive of our employees. Challenge and change were the name of the game for all three companies and our employees successfully rose to the challenges.

Brantford Power

Brantford Power continues to achieve its long-standing goal of distributing electricity to our customers with a commitment to safety, reliability and cost, while supporting development in the City of Brantford.

However, we continue to be concerned about the impact of the ever-increasing cost of electricity on our community and the rest of Ontario. Customers should be aware of what is happening in the electrical industry today. Ontario has the second highest cost of power in North America based on factors that are beyond the control of Brantford Power, which accounts for approximately 25% of a customer's bill.

We are concerned that a report requested by the Ontario government last year stated that the province would be better served by only six or eight large utilities in the province, saving customers more than $500 million a year.

We do not agree that a large utility would better serve Brantford. The large utilities are not more efficient than Brantford Power, whose total costs to the typical consumer are lower.

A significant factor driving up electricity costs is the so-called global adjustment, basically the cost that customers must bear to pay for power produced from wind and power sources outside of the customary system. Some long-term contracts for these renewable sources are set at 10 times the price of normal power, creating an artificial economic situation for sources that are not as reliable. Solar, for example, has only a 20-per-cent reliability factor.

We have created an artificial economic situation that still requires back-up power and leads to the untenable situation where Ontario actually pays other jurisdictions to take our power when we have a surplus, while we are charging customers more than 12 cents a kilowatt/hour at peak times.

While these factors are beyond the control of Brantford Power, it is essential that we continue to improve our cost-effective distribution system for the benefit of our customers. Brantford Power also supports conservation programs that lower electricity consumption and overall costs.

Brantford Hydro

The two divisions of the retail company continue to show encouraging returns. Gas water heater rentals have grown significantly for the home comfort division, joined by tankless water heaters and water conditioners as popular products. We will continue to grow the business prudently using our capital resources.

NetOptiks has long proven itself as a successful and sound investment, providing a vital telecommunications super-highway for Brantford's businesses and institutions. Its affiliation with the City of Brantford ensures that we maintain our ability to attract new industry while serving the requirements of our existing businesses.

Brantford Generation

The Mohawk Street facility generated a net profit during the year for the first time since its inception, although we are disappointed with the gas volumes at year-end due to high levels of leachate that flooded the collection system, even after the clay cap was installed to seal the landfill site.

We are diligently pursuing remedial efforts in 2013, including the installation of test pumps in the wells. Depending on the results, we will decide how to move forward.

Senior Management Changes

The Board welcomes Catherine Barker-Hoyes as CEO of Brantford Hydro and Brantford Generation, who was appointed in August 2012, and Paul Kwasnik as CEO of Brantford Power, who was appointed in January 2013. We look forward to continuing business success under their leadership.

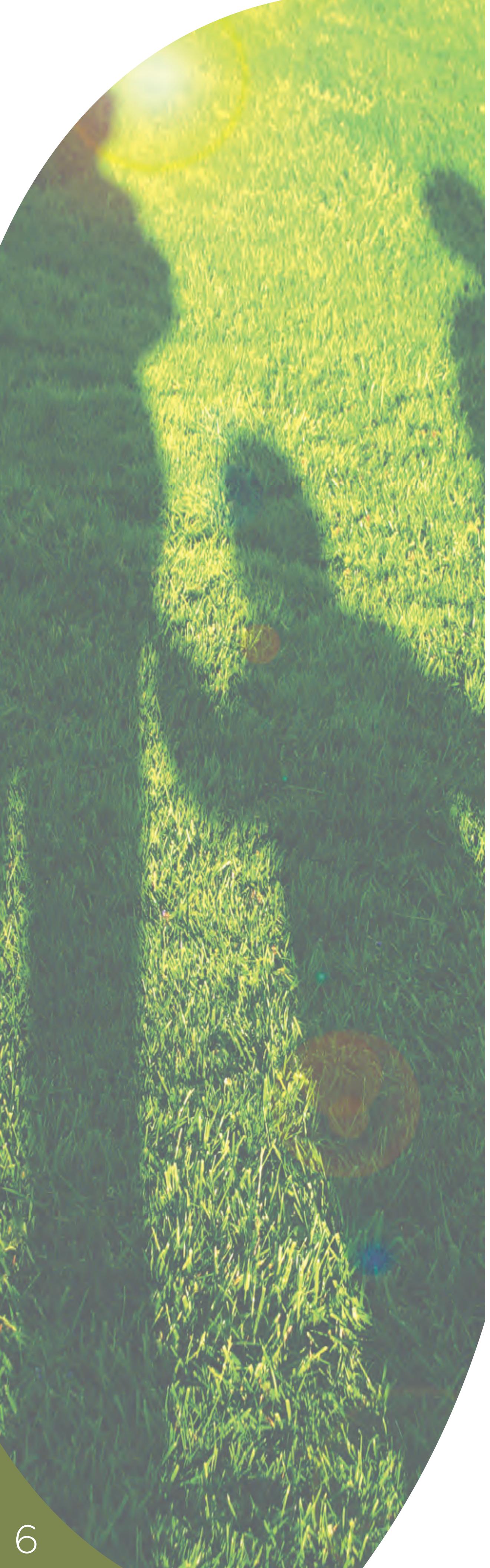
We pay particular tribute to George Mychailenko who retired as CEO of Brantford Power in January 2013 after serving 37 years with the utility. His leadership over the years ensures that this vital utility is well-positioned to meet the challenges of the future.

We also thank Brian D'Amboise for his services as CEO of Brantford Hydro and Brantford Generation. His appointment as CFO of Brantford Power recognizes the need for fulltime focus on that business under the new structure.

Financial Results

Consolidated net income of $2,140,000 compares to $3,000,000 reported in 2011. The year over year decline is largely due to lower Brantford Power distribution revenue resulting from the return to customers of $1,200,000 in payments-in-lieu of tax (PILS) over collections accumulated from 2002-2006. This decline was partially offset by Brantford Generation's first ever profit of $142,000.

Analysis of 2012 Net Income Contribution (In $1,000)			
Company	2012 Actual	2011 Actual	2010 Actual
Brantford Energy Corporation	Nil	Nil	Nil
Brantford Power Inc.	1,347,000	2,290,000	1,873,000
Brantford Hydro Inc.	651,000	710,000	660,000
Brantford Generation Inc.	142,000	Nil	(317,000)
Total	**$2,140,000**	**$3,000,000**	**$2,216,000**



Scott Saint
Chair, Brantford Power Inc.

BRANTFORD POWER INC.
Ensuring a sustainable future

After an eventful 2012, Brantford Power Inc. (BPI) has improved its ability to operate as a stand-alone independent business able to respond to an ever-changing and challenging industry environment. As a result Brantford Power is better positioned to continue to work towards a sustainable future.

The year's events included implementation of a restructuring plan to ensure compliance with Ontario Energy Board regulations concerning affiliate relationships. Employees migrated seamlessly into the organization and are now solely focused on serving customers.

New Leadership

In January 2013, George Mychailenko retired as Chief Executive Officer after 37 years with the utility. George began his career with the Public Utilities Commission of Brantford 1976 and served as CEO of Brantford Power after the industry was deregulated. The Board of Directors is appreciative for all of George's outstanding service and long commitment to the company, the electricity industry and the community.

In January 2013 the Board appointed Paul Kwasnik as Chief Executive Officer. Paul's involvement in the energy and customer service sectors spans 25 years and his leadership and change management experience makes him well qualified to build on BPI's existing strengths.

Under Paul's leadership BPI will continue to place the highest priority on the timeless values of public and employee health and safety, while ensuring service quality and reliability. It will invest in the automation of its asset management system, expected to place BPI among the industry leaders for a utility our size, improve customer communications; promote the conservation agenda and develop a strategic plan designed to carry the business forward for the next three years and beyond to drive Shareholder value.

Conservation and Demand Management

The company will continue to explain the benefits of conservation to customers. Our focus is promoting residential programs, in particular PeakSaver Plus, through involvement in local residential events.

Since the launch of the Home Assistance Program 249 homes have benefited from the installation of energy efficient measures. Currently an additional 107 applications have been received for the program and CDM staff will work with the City of Brantford's Social Housing department to increase participation in social housing throughout the summer.

Commercial and industrial customers are currently working on 73 equipment replacement incentive projects. From 2011 to date, Brantford Power has paid out $666,000 in incentives through the completion of 67 projects.

Capital Improvements

Total investment in property, plant and equipment during the year was $4 million compared to $4.6 million in 2011, bringing total property plant and equipment to $59.9 million, virtually unchanged from the 2011 level.

The investments in 2012 included upgrades to the powerline feeders, providing service to new subdivisions and townhomes, and annual pole replacements and general rebuilds to maintain service reliability.

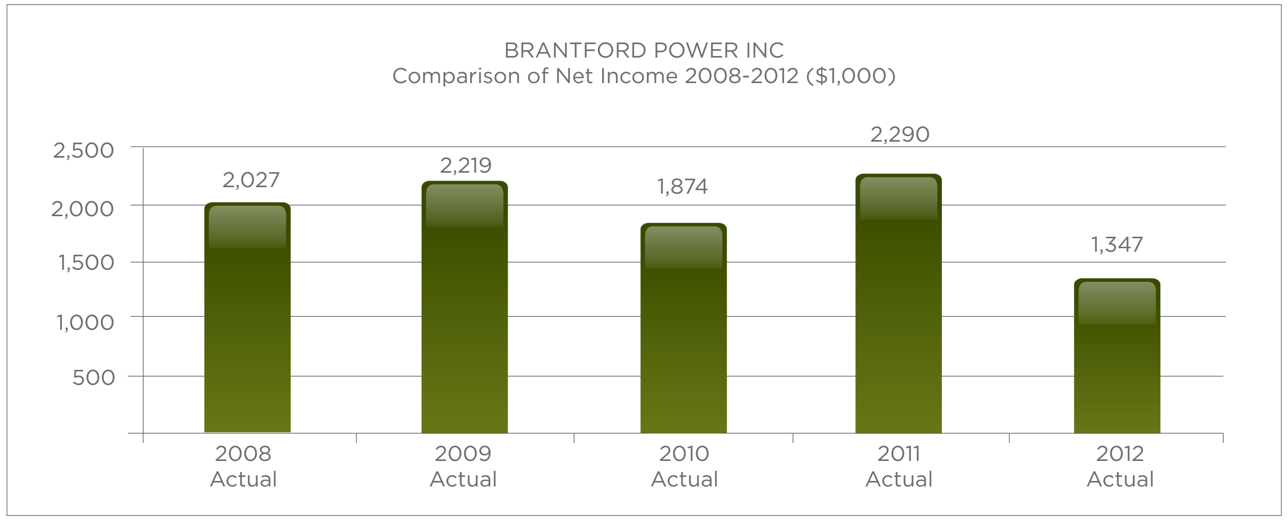
Financial Results

The company achieved a net income of $1,347,000 compared to $2,290,000 in 2011. The reduction was largely due to the return to customers in 2012 of some $1.2 million in accumulated over collections of payments in lieu of corporate tax recoveries from 2002-2006.

Despite the reduction in net income, the 2012 performance exceeded the budgeted target of $772,000 primarily due to lower than planned operating costs and higher than expected distribution and conservation and demand management margins. The year's performance reflects a 3.9% return on average equity, compared to 6.8% in 2011.

New Financing

The company's long-term debt has increased by $3.3 million due to the receipt of $4,230,000 in proceeds borrowed from the Ontario Infrastructure and Lands Corporation. This financing provided for deferred funding of the 2011 general capital expenditures and the last financing installment towards the completion of the smart meter program. These new borrowings were offset by scheduled principal payments on existing Royal Bank and Infrastructure Ontario long term debt.



Leo Renzella
Chair, Brantford Hydro Inc.

BRANTFORD HYDRO INC.
Growth in Sales and Services

Brantford Hydro Inc.'s (BHI) sales for both business units rose significantly in 2012 as a result of the positive full-year impact made by staff hires in 2011 that focused on increasing sales and expanding our products and services.

Enersure

The home comfort business profited due to continued growth in the products launched in 2011 that are marketed under the Enersure banner. These include natural gas water heaters, which have joined tankless water heaters and water conditioners as popular products in a market that demands more environmentally friendly technology.

NetOptiks

The fibre division continues to provide superior results while providing a vital service to the community. Both large and mid-sized businesses are discovering the benefits of ultra high-speed connectivity. During 2012 business growth came primarily in the insurance, hospitality and logistics sectors. As a result of continued growth NetOptiks now has more than 300 kilometres of fibre installed in Brantford.

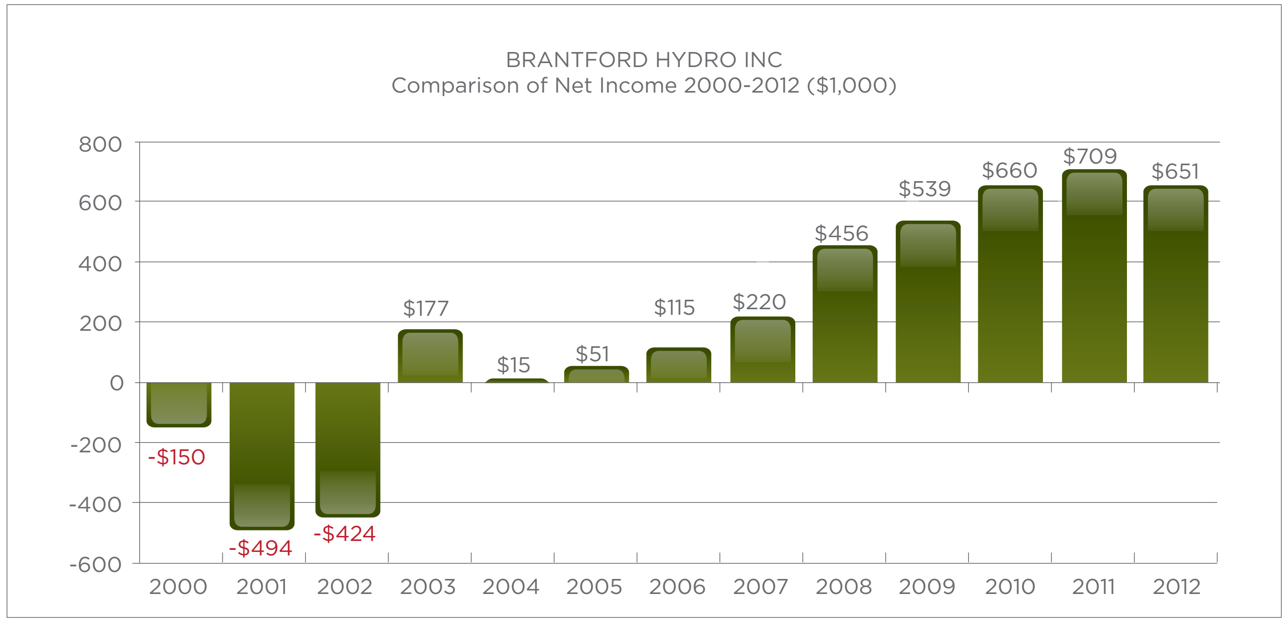
Management Changes

The Board welcomes Catherine Barker-Hoyes as CEO of Brantford Hydro. Catherine was appointed in August 2012 and we look forward to continuing business success under her leadership. We want to express our appreciation to Brian D'Amboise, our former CEO, and wish him well in his new position as CFO of Brantford Power.

Financial Results

BHI's net income of $651,000 represents a $59,000 decrease from 2011. The 2012 performance translates to a return on average equity of 24.7% (30.4% in 2011) and a return on assets of 13.9% (15.8% in 2011). Capital expenditures totaled $655,000 or 1.4 times the $467,000 spent in 2011.

As a result of solid financial performance, BHI has provided generous dividend payments to its shareholder, Brantford Energy Corporation, that are subsequently passed onto the City of Brantford to the benefit of city taxpayers. The company increased its 2012 dividend to $400,000, up from $350,000 in 2011 and $300,000 in 2010.



Leo Renzella
Chair, Brantford Hydro Inc.

BRANTFORD GENERATION INC.

Generating profit despite setback

With a significant increase in electricity generation, Brantford Generation Inc. (BGI) reported a profit in 2012 for the first time since its inception, although the company has not yet been able to achieve the production levels anticipated in the original business plan.

Production at the Mohawk Street Landfill Gas Collection and Utilization site ran ahead of the previous year's level during the summer after a clay cap was installed in May 2012 by the City of Brantford, generating positive financial results.

Production dropped in mid-September after leachate trapped within the landfill flooded the gas wells. Generation has remained essentially static since then. The company has applied to the Ontario Ministry of Environment to install 11 test pumps in the wells to remediate the flooding and monitor the projected level of improvement. We anticipate improved production levels once the pumps are approved and installed.

Environmental Benefits

The facility continued to provide environmental benefits for the community. Operations during 2012 collected and destroyed 10,674,259 cubic metres of landfill gas, or 74,244 tonnes of carbon dioxide equivalents. This represents the same greenhouse gas reductions achieved by removing 17,677 passenger vehicles from the roadways.

Management Changes

The Board welcomes Catherine Barker-Hoyes as CEO of Brantford Generation. Catherine was appointed in August 2012 and we look forward to continuing business success under her leadership. We want to express our appreciation to Brian D'Amboise, our former CEO, and wish him well in his new position as CFO of Brantford Power.

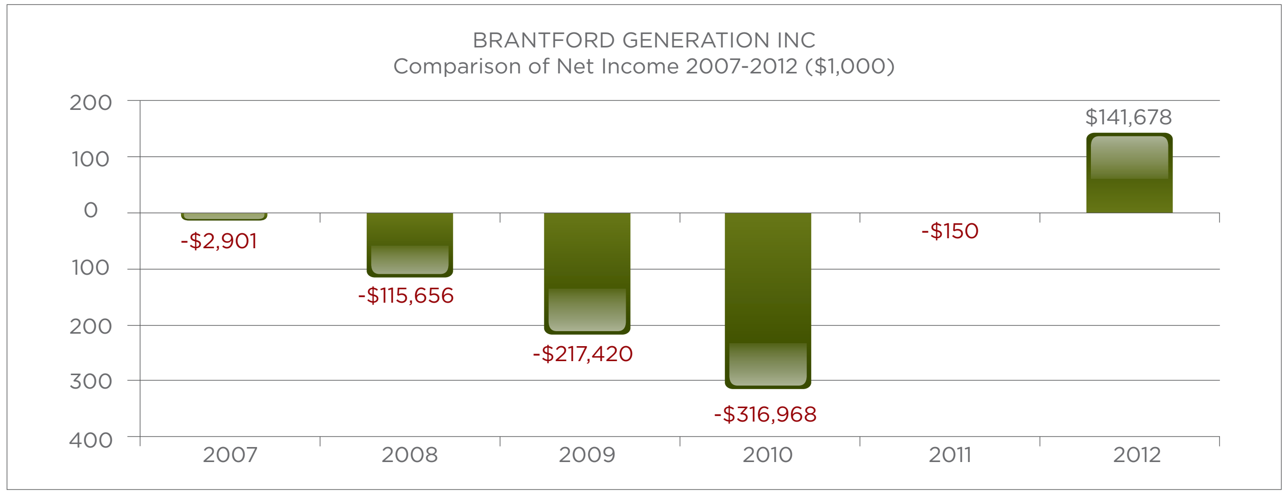
Financial Results

The company reported net income of $142,000 in 2012 compared to an operating loss of $150 in the previous year. Total generation revenues of $2,153,000 showed significant year-over-year improvement compared to $1,653,000 of revenues earned in 2011.

The company has not yet been able to achieve the production levels anticipated in the original business plan due in part to the lack of a clay cap at the landfill site in the first half of the year, which was subsequently completed in late May 2012, and flooding of the gas wells that began in mid-September 2012. Net income, as a result, was less than $451,000 budgeted for the year.

Cash flows from operations totaled $714,000. A portion of this positive cash flow was allocated to voluntary loan repayments of $200,000 to the Ontario Infrastructure and Lands Corporation (OILC). The balance is being kept as cash in reserve for remediation costs related to the flooding of the gas wells since the Ontario Infrastructure and Lands Corporation has suspended construction advances pending an evaluation of the long term outlook of the company.

BGI ended the year with $1,104,000 in cash, a significant improvement over the $580,000 level in 2011. As a result, 2012 working capital of -$186,000 is a substantial improvement over the level in 2011 of -$802,000.



FINANCIAL STATEMENTS

The accompanying summary consolidated financial statements, which comprise the summary consolidated balance sheet as at December 31, 2012, the summary consolidated income statement and retained earnings, and summary consolidated statement of flows for the year then ended, and related notes, are derived from the audited financial statements of Brantford Energy Corporation. The accompanying summary financial statements, which comprise the summary balance sheet as at December 31, 2012, the summary income statement and retained earnings, and summary statement of flows for the year then ended, and related notes, are derived from the audited financial statements of Brantford Power Inc., Brantford Hydro Inc. and Brantford Generation Inc. (the "Companies") for the year ended December 31, 2012. We expressed unmodified audit opinions on those (consolidated) financial statements in our reports dated May 2, 2013, March 28, 2013, April 30, 2013, and April 30, 2013; respectively. Those (consolidated) financial statements, and the summary (consolidated) financial statements, do not reflect the effects of events that occurred subsequent to the dates of our report on those (consolidated) financial statements.

The summary (consolidated) financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles applied in the preparation of the audited (consolidated) financial statements of the Companies. Reading the summary (consolidated) financial statements, therefore, is not a substitute for reading the audited (consolidated) financial statements of the Companies.

Management's Responsibility for the Summary (Consolidated) Financial Statements

Management is responsible for the preparation of a summary of the audited (consolidated) financial statements in accordance with Canadian generally accepted accounting principles.

Auditor's Responsibility

Our responsibility is to express an opinion on the summary (consolidated) financial statements based on our procedures, which were conducted in accordance with Canadian Auditing Standard (CAS) 810, "Engagements to Report on Summary Financial Statements."

Opinion

In our opinion, the summary consolidated financial statements derived from the audited consolidated financial statements of Brantford Energy Corporation and the summary financial statements derived from the audited financial statements of Brantford Power Inc., Brantford Hydro Inc. and Brantford Generation Inc. for the year ended December 31, 2012 are a fair summary of those financial (consolidated) statements, in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Professional Accountants,
Chartered Accountants

Licensed Public Accountants

Burlington, Ontario

BRANTFORD ENERGY CORPORATION

SUMMARIZED CONSOLIDATED BALANCE SHEET AS AT DECEMBER 31	2012 ($)	2011 ($)
ASSETS		
Current assets	37,162,013	30,957,118
Property, plant and equipment	74,585,257	74,905,342
Regulatory assets	5,218,627	4,147,328
Other assets	6,673,344	7,120,351
TOTAL ASSETS	**123,639,241**	**117,130,139**
LIABILITIES		
Current liabilities	18,049,642	15,581,543
Regulatory liabilities	6,180,082	7,329,824
Long term debt	58,234,516	55,174,469
Other liabilities	3,664,369	2,790,568
TOTAL LIABILITIES	**86,128,609**	**80,876,404**
SHAREHOLDER'S EQUITY		
Capital stock	23,895,512	23,895,512
Retained earnings	13,866,967	12,876,502
Contributed surplus	141,319	-
Accumulated other comprehensive loss	(393,166)	(518,279)
TOTAL EQUITY	**37,510,632**	**36,253,735**
TOTAL LIABILITIES & EQUITY	**123,639,241**	**117,130,139**
	-	-

SUMMARIZED CONSOLIDATED STATEMENT OF INCOME AND RETAINED EARNINGS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
REVENUE		
Electricity distribution and service revenue	14,336,994	15,158,434
Fibre optic and retail service revenue	2,676,051	2,517,636
Generation revenue	2,131,230	1,641,833
Other revenue	4,985,225	1,783,243
	24,129,500	**21,101,146**
EXPENSES		
Operations, maintenance and administration	10,332,822	9,002,821
Other expenses	10,916,885	8,172,469
	21,249,707	**17,175,290**
Income Before Income Taxes	**2,879,793**	**3,925,856**
Current and Future Income Taxes	**739,328**	**926,165**
NET INCOME	**2,140,465**	**2,999,691**
Retained Earnings - Beginning of Year	**12,876,502**	**11,676,811**
Restructuring effects	**141,319**	**-**
Dividends	**(1,150,000)**	**(1,800,000)**
Retained Earnings - End of Year	**14,008,286**	**12,876,502**
	-	-

SUMMARIZED CONSOLIDATED STATEMENT OF CASH FLOWS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	2,140,465	2,999,691
Changes to income not involving cash	6,715,747	6,165,905
Net change in non-cash working capital balances related to operations	885,834	(482,484)
	9,742,046	**8,683,112**
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchase of property, plant and equipment and special deposits	(5,002,992)	(5,537,800)
Change in regulatory assets and liabilities	(2,221,041)	(2,780,734)
	(7,224,033)	**(8,318,534)**
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds of issuance of long-term debt	4,230,000	550,000
Repayment of long-term debt	(810,501)	(567,012)
Capital contribution, customer deposits and deferred revenues	375,843	(62,192)
Dividends	(1,150,000)	(1,800,000)
	2,645,342	**(1,879,204)**
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**5,163,355**	**(1,514,626)**
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**11,277,852**	**12,792,478**
CASH AND CASH EQUIVALENTS, END OF YEAR	**16,441,207**	**11,277,852**

BRANTFORD POWER INC.

SUMMARIZED BALANCE SHEET AS AT DECEMBER 31	2012 ($)	2011 ($)
ASSETS		
Current assets	34,508,159	28,634,115
Property, plant and equipment	59,942,622	59,873,172
Regulatory assets	5,218,627	4,147,328
Other Assets	6,310,521	6,784,956
TOTAL ASSETS	**105,979,929**	**99,439,571**
LIABILITIES		
Current liabilities	16,973,892	14,303,812
Regulatory liabilities	6,180,082	7,329,824
Long term debt	44,179,375	40,919,451
Other liabilities	3,504,951	2,608,352
TOTAL LIABILITIES	**70,838,300**	**65,161,439**
SHAREHOLDER'S EQUITY		
Capital stock	22,437,505	22,437,505
Retained earnings	12,955,971	12,358,906
Contributed surplus	141,319	-
Accumulated other comprehensive loss	(393,166)	(518,279)
TOTAL EQUITY	**35,141,629**	**34,278,132**
TOTAL LIABILITIES & EQUITY	**105,979,929**	**99,439,571**
	-	-

SUMMARIZED STATEMENT OF INCOME AND RETAINED EARNINGS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
REVENUE		
Distribution revenue	14,336,994	15,158,434
OPA Conservation programs revenue	4,020,508	723,014
Other revenue	979,300	1,080,134
	19,336,802	**16,961,582**
EXPENSES		
Operations, maintenance and administration	11,560,939	7,706,172
Other expenses	5,931,768	6,195,764
	17,492,707	**13,901,936**
Income Before Income Taxes	**1,844,095**	**3,059,646**
Current and Future Income Taxes	**497,030**	**770,034**
NET INCOME	**1,347,065**	**2,289,612**
Retained Earnings - Beginning of Year	**12,358,906**	**11,519,294**
Transition adjustment on adoption of future income taxes	**-**	**-**
Dividends	**(750,000)**	**(1,450,000)**
Retained Earnings - End of Year	**12,955,971**	**12,358,906**
	-	-

SUMMARIZED STATEMENT OF CASH FLOWS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	1,347,065	2,289,612
Changes to income not involving cash	5,710,164	5,170,194
Net change in non-cash working capital balances related to operations	995,013	(599,971)
	8,052,242	**6,859,835**
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchase of property, plant and equipment and special deposits	(4,358,084)	(4,423,209)
Change in regulatory assets and liabilities	(2,221,041)	(2,780,734)
	(6,579,125)	**(7,203,943)**
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds of issuance of long-term debt	4,230,000	550,000
Repayment of long-term debt	(610,501)	(567,012)
Capital contributions and customer deposits	392,164	(169,348)
Dividends	(750,000)	(1,450,000)
	3,261,663	**(1,636,360)**
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**4,734,780**	**(1,980,468)**
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**9,200,282**	**11,180,750**
CASH AND CASH EQUIVALENTS, END OF YEAR	**13,935,062**	**9,200,282**

BRANTFORD HYDRO INC.

SUMMARIZED BALANCE SHEET AS AT DECEMBER 31	2012 ($)	2011 ($)
ASSETS		
Current assets	2,072,140	2,214,326
Property, plant and equipment	2,581,893	2,274,111
Other assets	20,977	15,290
TOTAL ASSETS	**4,675,010**	**4,503,727**
LIABILITIES		
Current liabilities	375,254	447,447
Long term debt	1,303,335	1,303,335
Other liabilities	233,373	240,871
TOTAL LIABILITIES	**1,911,962**	**1,991,653**
SHAREHOLDER'S EQUITY		
Capital stock	1,338,006	1,338,006
Retained earnings (deficit)	1,425,042	1,174,068
TOTAL EQUITY	**2,763,048**	**2,512,074**
TOTAL LIABILITIES & EQUITY	**4,675,010**	**4,503,727**
	-	-

SUMMARIZED STATEMENT OF INCOME AND RETAINED EARNINGS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
REVENUE		
Fibre optic and retail service revenue	2,687,991	2,529,576
Other revenue	26,388	25,321
	2,714,379	2,554,897
EXPENSES		
Operations, maintenance and administration	1,450,199	1,245,771
Other expenses	410,808	371,066
	1,861,007	1,616,837
Income Before Income Taxes	**853,372**	**938,060**
Current and Future Income Taxes	**202,398**	**228,580**
NET INCOME	**650,974**	**709,480**
Retained Earnings (Deficit) - Beginning of Year	**1,174,068**	**814,588**
Dividends	**(400,000)**	**(350,000)**
Retained Earnings (Deficit) - End of Year	**1,425,042**	**1,174,068**
	-	-

SUMMARIZED STATEMENT OF CASH FLOWS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	650,974	709,480
Changes to income not involving cash	348,115	295,770
Net change in non-cash working capital balances related to operations	(7,490)	(172,825)
	991,599	**832,425**
CASH FLOWS FROM INVESTING ACTIVITY		
Purchase of property, plant and equipment	(654,794)	(466,900)
CASH FLOWS FROM FINANCING ACTIVITIES		
Capital contributions, customer deposits, and deferred revenues	(9,366)	106,446
Dividends	(400,000)	(350,000)
	(409,366)	(243,554)
NET INCREASE IN CASH AND CASH EQUIVALENTS	**(72,561)**	**121,971**
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**1,451,335**	**1,329,364**
CASH AND CASH EQUIVALENTS, END OF YEAR	**1,378,774**	**1,451,335**

BRANTFORD GENERATION INC.

SUMMARIZED BALANCE SHEET AS AT DECEMBER 31	2012 ($)	2011 ($)
ASSETS		
Current assets	1,112,033	594,142
Property, plant and equipment	12,063,368	12,761,433
Other assets	413,358	375,200
TOTAL ASSETS	**13,588,759**	**13,730,775**
LIABILITIES		
Current liabilities	1,298,370	1,382,187
Long term debt	12,751,806	12,951,683
TOTAL LIABILITIES	**14,050,176**	**14,333,870**
Capital Deficiency		
Capital Stock	50,000	50,000
Deficit	(511,417)	(653,095)
TOTAL CAPITAL DEFICIENCY	**(461,417)**	**(603,095)**
TOTAL LIABILITIES & EQUITY	**13,588,759**	**13,730,775**
	-	-

SUMMARIZED STATEMENT OF INCOME AND RETAINED EARNINGS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
REVENUE		
Generation revenue	2,131,230	1,641,833
Other revenue	21,679	10,984
	2,152,909	1,652,817
EXPENSES		
Operations, maintenance and administration	1,080,231	854,184
Other expenses	891,100	871,232
	1,971,331	1,725,416
Loss Before Income Taxes	**181,578**	**(72,599)**
Current and Future Income Taxes	**39,900**	**(72,449)**
NET INCOME/(LOSS)	**141,678**	**(150)**
Deficit - Beginning of Year	**(653,095)**	**(652,945)**
Deficit - End of Year	**(511,417)**	**(653,095)**
	-	-

SUMMARIZED STATEMENT OF CASH FLOWS FOR THE YEAR ENDING DECEMBER 31	2012 ($)	2011 ($)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income/(Loss)	141,678	(150)
Changes to income not involving cash	650,144	700,285
Net change in non-cash working capital balances related to operations	(78,130)	278,872
	713,692	979,007
CASH FLOWS FROM INVESTING ACTIVITY		
Purchase of property, plant and equipment	9,886	(647,689)
CASH FLOWS FROM FINANCING ACTIVITY		
Proceeds of issuance of long-term debt	(200,000)	-
NET INCREASE IN CASH AND CASH EQUIVALENTS	**523,578**	**331,318**
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**580,085**	**248,767**
Cash and Cash Equivalents, End of Year	**1,103,663**	**580,085**

BRANTFORD ENERGY CORPORATION

BRANTFORD HYDRO INC.

Mission
As a growth company, Brantford Hydro Inc. delivers environmentally sustainable telecommunications and energy related services that enhance the competitiveness of businesses and the quality of life for customers.

Vision
The vision of Brantford Hydro Inc. is to become a leader in Brantford and surrounding areas by growing our business lines through strategic investments and partnerships enhancing the value of the company to both our customers and shareholder.

Values
- We value open and honest communication with internal and external stakeholders as we strive for success in a competitive business environment.
- We seek to ensure maximum customer satisfaction by delivering exceptional value through the provision of efficient and dependable products and services.
- We value our customers, business partners and other stakeholders and will treat them with fairness, respect and integrity as they are integral components to our success.
- We value innovation in services, thinking and actions.
- We anticipate and adapt quickly and effectively to the ever changing business landscape.

BRANTFORD POWER INC.

Mission
Brantford Power provides safe, reliable and competitively priced services to our customers while ensuring excellent shareholder returns.

Vision
Brantford Power is driven to be a leading electricity distribution company.

Values
- Safety
- Openness and integrity in all relationships
- Innovation and creativity
- A customer focus
- Employee engagement

BOARD OF DIRECTORS

BRANTFORD ENERGY CORP.

James F. Ryan
Chair

Leo Renzella
Retired

Scott Saint
(from April 2012)
COO, Electrical Safety Authority

Mayor Chris Friel
City of Brantford

Councillor Vince Bucci
Ward 2, City of Brantford

Councillor John Utley
Ward 2, City of Brantford

Councillor Larry Kings
Ward 1, City of Brantford

Councillor Debi Dignan-Rumble
Ward 3, City of Brantford

BRANTFORD POWER INC.

Scott Saint, Chair
(from April 2012)
COO, Electrical Safety Authority

Ron Stewart, Chair
(to April 2012)
Retired

Timothy B. Curtis
(to September 2012)
Regional Controller, TransUnion

Paul Kwasnik
(to August 2012)
Principal
PJK Advisory Group

Neil Sandford
(from October 2012)
Senior Vice President
AESI Acumen Engineered Solutions Inc.

Terry Smith
(from October 2012)
President, O2Z Corporation

Councillor John Utley
Ward 2, City of Brantford

BRANTFORD HYDRO INC.
BRANTFORD GENERATION INC.

Leo Renzella, Chair
Retired

Gerry Smits, Chair
(to April 2012)

Rick Sterne
Retired

Drew Hill
The Abor Group

Councillor Larry Kings
Ward 1, City of Brantford

EXECUTIVE TEAM

Ted Salisbury
CAO, City of Brantford
CEO, Brantford Energy Corporation

George Mychailenko
CEO, Brantford Power Inc.
(to January 2013)

Catherine Barker-Hoyes
CEO, Brantford Hydro Inc.
CEO, Brantford Generation Inc.
(from August 2012)

OFFICERS

Catherine Barker-Hoyes
CFO Brantford Energy Corporation

Brian D'Amboise
CFO, Brantford Power Inc.

Catherine Barker-Hoyes
CFO Brantford Hydro Inc.
CFO Brantford Generation Inc.

James Nagle
COO, Brantford Hydro Inc.
COO, Brantford Generation Inc.

Heather Wyatt
Board Secretary, Brantford Power Inc.

Sarah Hewitt
Board Secretary Brantford Energy Corporation
Board Secretary, Brantford Hydro Inc.
Board Secretary, Brantford Generation Inc.

AUDITOR

Deloitte LLP
Chartered Accountants
Licensed Public Accountants

ATTACHMENT F

REFERENCE: 1.0 HVAC-4

BRANTFORD POWER INC.
Strategic Plan for 2010-2013

Brantford Power Inc. (BPI) has completed a strategic planning process to review its priorities and identify future directions. The new strategic plan was developed with extensive stakeholder involvement.

Planning steps completed were the following:

- In the fall of 2009 the BPI Board identified the need to develop a new strategic plan and selected an external consultant in to facilitate the planning process. The work plan was approved on October 16, 2009.

- The consultant reviewed background information and held individual and group discussions with Board members, key individuals in the community and some management and staff members.

- On February 25, 2010 the Board and members of the Senior Management Team participated in a five-hour strategy development session. They completed a situation analysis, engaged in visioning activities, reviewed decision options and developed some initial high level goals for the Corporation.

- A discussion paper describing the emerging strategic plan and containing specific focus questions was distributed to staff in March. Focus groups attended by 26 staff members were held on April 29, 2010. Several other individuals submitted individual responses to the paper.

- Members of the BPI management team met on May 3 to review the consultation input and identify preliminary strategies to move the goals forward

The plan will be reviewed by the BPI Board of Directors on Wednesday, June 2, 2010. Following Board approval, detailed implementation plans will be finalized and the plan will be used to guide the Corporation as it addresses its strategic opportunities and challenges of the coming years.

Attached: Mission, Vision and Values
Strategic Goals and Objectives
Keeping the Plan Alive
Planning Model

June 2010

MISSION, VISION AND VALUES

Mission Statement

A mission statement should be a clear statement of the purpose, mandate and "business" of an organization. BPI's mission statement was revised slightly and appears below:

> **As a leading electricity distribution company, Brantford Power is driven to provide safe, reliable and competitively priced services to our customers, while providing above average growth in shareholder value and excellent returns on shareholder investment.**

Vision Statement

A vision statement describes the "preferred future state" of an organization and its stakeholders. Participants at the February planning retreat engaged in a visioning exercise and identified the following elements of a new vision for BPI:

> **Innovation and leadership in the energy industry**
> **Performance and efficiency**
> **Organizational growth and development**

Values

Values are those beliefs that guide an organization as it discharges its mission in pursuit of its vision. BPI's values were also revised and appear below:

- **Safety**
- **Openness and integrity in relationships with our stakeholders**
- **Innovative and future oriented services**
- **A customer focus with responsive, friendly, efficient and reliable service**
- **A positive, challenging and rewarding work environment**

Detailed descriptions of each value, along with definitions and behaviour statements will need to be prepared by BPI staff.

EMERGING DIRECTIONS: Strategic Goals and Objectives

Four high-level goals for BPI emerged from the planning process. The first three are considered strategic imperatives that will define the Corporation's direction and priorities. These core goals pertain to quality, innovation/leadership and external relationships.

The final goal, related to organizational development is considered an enabler. This goal needs to be achieved first in order for BPI to meet its strategic imperatives and address its key priorities.

STRATEGIC IMPERATIVES:

1.0 Pursue quality, efficiency and service excellence

1.1 Align the organization around continuous improvement to consistently achieve "Best in Class" unit cost and quality results.

1.2 Align service providers with continuous improvement targets.

1.3 Continue to grow regulatory expertise and depth.

1.4 Leverage technology and capital to gain productivity improvements.

2.0 Innovate and provide leadership

2.1 Maintain and strategically expand the asset base to support community and economic development.

2.2 Develop profitable ancillary business lines that leverage the Green Energy Act and build on the success of the conservation program.

EMERGING DIRECTIONS (Cont'd)

3.0 Build external relationships

3.1 Pursue strategic partnerships and other affiliations with organizations outside of the BPI catchment area.

3.2. Develop closer relations with Ontario Energy Board and interveners to expand influence in industry and regulatory policy.

3.3 Increase stakeholder knowledge of the value, opportunities and risks associated with the organization.

ENABLER

4.0 Create a forward-looking organizational culture that supports innovation and collaboration

4.1 Improve internal communication.

4.2 Increase employee engagement.

4.3 Grow expertise in all areas of the organization.

KEEPING THE PLAN ALIVE

BPI's core strategic directions pertain to quality, innovation/leadership, and positive and effective external relationships. The organization is well positioned to meet its strategic challenges with a committed board and a seasoned staff. However, a new plan is like a new vehicle - it depreciates by 30 percent during each year of service. The turbulence of the energy industry will necessitate ongoing "service and maintenance" of BPI's strategic plan by monitoring, refining and periodically revising goals and objectives.

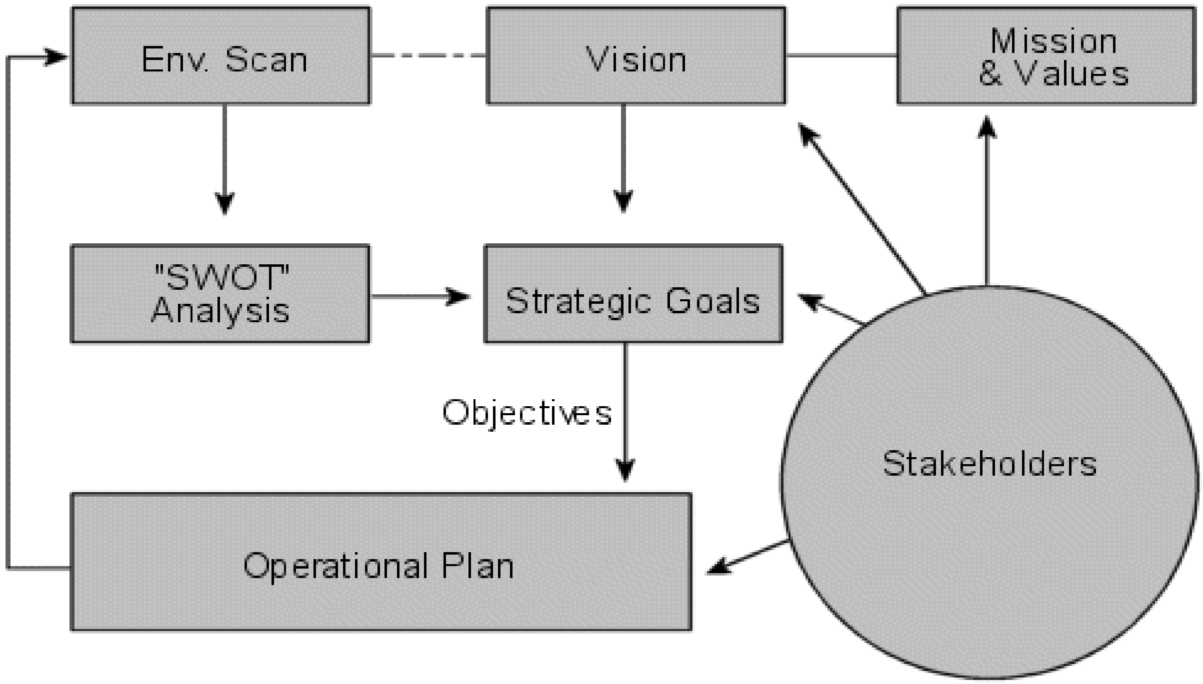
While the Corporation's management is responsible for achieving the goals and objectives in the strategic plan, the Board of Directors is responsible for providing "stewardship" of the plan by keeping it relevant, valid and vital. Ensuring that strategic plans remain as "living documents" is the essence of effective governance. Suggested board roles related to the various components of the strategic plan are described below:

Environment:	The environmental scan information gathered during the planning process should be monitored closely. Board discussions about trends, events and emerging issues should be explicit and ongoing.
SWOT:	As part of the environmental scanning process, BPI's strengths, weaknesses, opportunities and threats should be reviewed regularly and revised as goals are achieved and factors change.
Mission:	BPI's mission statement is the most stable and constant component of the strategic plan. However, as goals are achieved or major environmental changes occur, revisions may be appropriate.
Vision:	The vision elements articulated in the strategic planning process should be front and centre in all discussions related to future directions of the organization. Organizational initiatives under consideration should be assessed in terms of their contribution potential for moving BPI towards its "preferred future".
Goals:	Strategic goals should always be monitored against outcome measures with progress reports from staff at key milestones. The BPI Board and management may periodically need to shift the emphasis and nature of the directions based on information from the ongoing environmental scan and changes to the SWOT analysis. Board members therefore should monitor goals on two tracks and continually be asking two key questions: • What is our progress towards these goals? • Are the goals still relevant?

Dr. David Sheridan
Senior Consultant and Principal
SHERCON ASSOCIATES INC.
www.shercon.ca

May 2010

THE STRATEGIC PROCESS
(Model followed during BPI's planning process)



Environment – Environmental scanning is the starting point for any strategic planning process. It should include trends, events and emerging issues in the economic, technological, demographic and political domains, as well as a close examination of the nature of the organization itself.

SWOT Analysis – The SWOT analysis is based on environmental data and delineates present strengths and weaknesses in the internal environment as well as future threats and opportunities in the external environment.

Vision – A description of the desired "future state" of the organization.

Mission and Values – A statement of purpose for the organization and an articulation of the values important to its stakeholders.

Goals – Broad statements of strategic direction. Good strategic goals are a mix of dreams (the vision) and reality (the SWOT analysis).

Stakeholders – Identified in the environmental scanning stage, stakeholders should be formally and appropriately involved throughout the planning process.

Operational (Implementation) Plan – A specific and detailed set of actions necessary for meeting strategic objectives. It includes time frames, responsibilities and resource allocations. Monitoring and ongoing revision is a crucial component.

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ATTACHMENT G

REFERENCE: 2.0 Energy Probe-14

2013 COST OF POWER FORECAST

2013 Load Foreacst	kWh	kW	2011 %RPP
Residential	272,082,836		87%
General Service < 50 kW	94,447,805		90%
General Service 50 to 4,999 kW	523,567,859	1,332,860	26%
Street Lighting	7,553,004	23,455	0%
Sentinel Lighting	443,490	1,356	0%
Unmetered Scattered Load	1,454,727		0%
Hydro One			0%
TOTAL	**899,549,721**	**1,357,672**	

Electricity - Commodity RPP	2013 Forecasted Metered kWhs	2013 Loss Factor			
Class per Load Forecast RPP				2013	
Residential	236,712,068	1.0349	244,973,908	$0.08395	$20,565,560
General Service < 50 kW	85,003,024	1.0349	87,969,841	$0.08395	$7,385,068
General Service 50 to 4,999 kW	136,127,643	1.0349	140,878,837	$0.08395	$11,826,778
Street Lighting	0	1.0349	0	$0.08395	$0
Sentinel Lighting	0	1.0349	0	$0.08395	$0
Unmetered Scattered Load	0	1.0349	0	$0.08395	$0
Hydro One	0	1.0349	0	$0.08395	$0
TOTAL	**457,842,735**		**473,822,586**		**$39,777,406**

Electricity - Commodity Non-RPP	2013 Forecasted Metered kWhs	2013 Loss Factor			
Class per Load Forecast				2013	
Residential	35,370,769	1.0349	36,605,297	$0.08545	$3,127,923
General Service < 50 kW	9,444,780	1.0349	9,774,427	$0.08545	$835,225
General Service 50 to 4,999 kW	387,440,216	1.0349	400,962,844	$0.08545	$34,262,275
Street Lighting	7,553,004	1.0349	7,816,623	$0.08545	$667,930
Sentinel Lighting	443,490	1.0349	458,969	$0.08545	$39,219
Unmetered Scattered Load	1,454,727	1.0349	1,505,500	$0.08545	$128,645
Hydro One	0	1.0349	0	$0.08545	$0
TOTAL	**441,706,986**		**457,123,659**		**$39,061,217**

Transmission - Network		Volume Metric			
Class per Load Forecast				2013	
Residential		kWh	281,579,205	$0.0084	$2,365,265
General Service < 50 kW		kWh	97,744,268	$0.0076	$742,856
General Service 50 to 4,999 kW		kW	1,332,860	$2.5958	$3,459,839
Street Lighting		kW	23,455	$2.3960	$56,199
Sentinel Lighting		kW	1,356	$2.4240	$3,287
Unmetered Scattered Load		kWh	1,505,500	$0.0076	$11,442
Hydro One		kWh	0	$2.5958	$0
TOTAL					**$6,638,889**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	281,579,205	$0.0057	$1,605,001
General Service < 50 kW		kWh	97,744,268	$0.0049	$478,947
General Service 50 to 4,999 kW		kW	1,332,860	$1.6850	$2,245,870
Street Lighting		kW	23,455	$1.5555	$36,485
Sentinel Lighting		kW	1,356	$1.5737	$2,134
Unmetered Scattered Load		kWh	1,505,500	$0.0049	$7,377
Hydro One		kWh	0	$1.6850	$0
TOTAL					**$4,375,814**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential			281,579,205	$0.0044	$1,238,949
General Service < 50 kW			97,744,268	$0.0044	$430,075
General Service 50 to 4,999 kW			541,841,681	$0.0044	$2,384,103
Street Lighting			7,816,623	$0.0044	$34,393
Sentinel Lighting			458,969	$0.0044	$2,019
Unmetered Scattered Load			1,505,500	$0.0044	$6,624
Hydro One			0	$0.0044	$0
TOTAL			**930,946,246**		**$4,096,163**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential			281,579,205	$0.0012	$337,895
General Service < 50 kW			97,744,268	$0.0012	$117,293
General Service 50 to 4,999 kW			541,841,681	$0.0012	$650,210
Street Lighting			7,816,623	$0.0012	$9,380
Sentinel Lighting			458,969	$0.0012	$551
Unmetered Scattered Load			1,505,500	$0.0012	$1,807
Hydro One			0	$0.0012	$0
TOTAL			**930,946,246**		**$1,117,135**

	2013
4705-Power Purchased	$78,838,623
4708-Charges-WMS	$4,096,163
4714-Charges-NW	$6,638,889
4716-Charges-CN	$4,375,814
4730-Rural Rate Assistance	$1,117,135
4750-Low Voltage	
TOTAL	**95,066,625**

ATTACHMENT H

REFERENCE: 2.0 SEC-8

CAPITAL PLAN 2014

1. NEW LINES & EQUIPMENT

General Description: The New Lines and Equipment capital pool includes various essential and nondiscretionary builds. Projects in this pool include, among others:

- Secondary services for residential and commercial customers;
- Primary services including overhead and underground line, for industrial and commercial customers; and;
- Overhead and underground transformers for residential, commercial and industrial customers.

This capital pool is based on historical data as well as specific information provided by developers, electricians and engineering companies.

New Lines and Equipment Capital Projects include the following components:

Name of Capital Project	Services (Roll ins)
Capital Project #	1
USofA #	1855
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Roll-ins comprising mainly of residential customer connections
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2014
Forecasted Costs	$115,500
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Line Extensions
Capital Project #	2
USofA #	1830, 1835
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Overhead portions of mostly general service customer connections and pole lines
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2014

Forecasted Costs	$278,250
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Underground Line Extensions
Capital Project #	3
USofA#	1840, 1845
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Underground portions of mostly general service customer connections including cables and ducts
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting date	2014
Forecasted Costs	$294,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	All pole mount transformers for connection to residential and general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2014
Forecasted Costs	$47,250
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	Underground Transformers
Capital Project #	5
USofA #	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground

	transformers to customers.
Project Scope	All padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2014
Forecasted Costs	$378,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

2. POWERLINE FEEDER UPGRADES

General Description: Powerline Feeder Upgrades comprise of various essential and nondiscretionary builds. Projects include:

- Increase number of circuits into BPI's distribution territory to meet the potential for future demand;
- Install larger poles for future circuits.

Name of Capital Project:	Powerline Feeder upgrades – MS#2 to Greenfield Road - Phase 6
USofA #	6
Capital Project #	1835, 1840
Project Need and Purpose	The project comprises of replacing existing poles to cover approx. 8km length of the circuit extending from Powerline Municipal Transformer Station to the North-East end of the City. The expected completion is in 2016.
Project Scope:	Phase 6 comprises the portion from MS#2 to Greenfield Road
# of Customer Attachments	N/A
Load	N/A
Cost-benefit analysis, as applicable	The alternate to extending this feeder was to build a 2nd Transformer Station (after Powerline MTS) in the North-East end of the City. The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline MTS which has the capacity to cater to the existing and future loading needs.
Starting Date	2014

Forecasted Cost	$360,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Competitive bidding process

3. NEW SUBDIVISIONS AND TOWNHOMES

General Description: The new subdivisions and new townhomes capital budget pool comprises essential and nondiscretionary projects to support new development. Work is required to connect new subdivisions and townhouses, principally through new underground conduit, conductors and devices to the distribution infrastructure.

Beginning in 2008 with the implementation of proposed changes to BPI's Conditions of Service and redefinition of the demarcation point from the property line to the meter base, BPI assumed ownership of connection assets to the meter base of new townhome projects. As expansion projects, the Economic Evaluation model is applied to all new subdivision and new townhome projects.

Name of Capital Project:	Wynfield West - Stage 4
Capital Project #	7
USofA #	1840, 1845, 1850
Project Need and Purpose	Estimated connection of 150 subdivision units and 50 townhome units
Project Scope	The project comprises of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure.
Load	Estimated as 730 kwh per lot per year
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$468,405
Capital Contribution Forecast	$228,893
Who performed the work [in-house vs. contracted]	Majority of the work is performed by building contractors as sub to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

4. CITY/MINISTRY OF TRANSPORTATION RELOCATIONS

General Description: Prioritized as nondiscretionary essential capital projects, these projects involved relocation of overhead lines resulting from municipal or provincial road infrastructure projects.

Capital budget costs for system expansions and municipal and Ministry of Transportation Road Relocation Projects are presented as gross costs and do not include offsets for grants and grants and contributions which are booked to USoA Account 1995.

Name of Capital Project:	City /Ministry of Transportation Relocations
Capital Project #	8
USofA #	1830, 1835
Project Need and Purpose	Relocation of overhead lines resulting from municipal or provincial road infrastructure projects.
Project Scope	It is often impossible to forecast what projects will require any relocation work because the final road designs are not finalized at the time when we submit our budget. Add to that, the City's road construction program can add or subtract streets at any time.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$52,500
Capital Contribution Forecast	$13,125
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Tender

Name of Capital Project:	Shellard Lane (West city limits to Colborne West) - Relocation
Capital Project #	9
USofA #	1830,1835
Project Need and Purpose	The City is widening the road and installing a 3m wide walking/bicycle path which requires relocating the existing pole line.
Project Scope	Install new poles and transfer existing wires to new poles.
Cost-benefit analysis, as applicable	N/A

Starting Date	2014
Forecasted Costs	$265,000
Capital Contribution Forecast	$70,273
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

5. DALHOUSIE ST. – DOWNTOWN – NEW BUILD –PHASE 1 – PROJECT COORDINATION AND DESIGN

Name of Capital Project:	Dalhousie St. (downtown relocations) Clarence St. to Brant Ave – Phase 1
Capital Project #	10
USofA #	1840,1845
Project Need and Purpose	The City is reconstructing the road and installing new infrastructure. BPI will install new plant to replace the aging infrastructure with the capability to supply future demands. There may be a need to relocate existing plant because of conflict with the proposed road design.
Project Scope	BPI will be installing new vaults, duct banks and cables in three blocks (Market to Bridge) at the same time as the road construction (2016). BPI will also relocate existing plant at the same time. Project coordination and design will occur in 2014 and 2015.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	Start design/coordination in 2014, continue in 2015 and construction in 2016
Forecasted Costs	$25,000
Capital Contribution Forecast	$2,000
Who performed the work [in-house vs. contracted]	In-house design work
Procurement method where work was contracted	N/A

6. OAK PARK ROAD NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS [M12 and M13 FEEDERS]

General Description: Budgets were set aside in 2008 and 2009 in anticipation of the Oak Park Road N. industrial servicing and line relocation which was a major project, however, after submission of initial drawings, there was no further movement from the developer. The project has been deferred year after year, but forecasted from 2014 through 2017 should the developer decide to move forward with the development. If executed, it is anticipated that 2014/2015 would see the major part of the pole line built and 2016/2017 would budget contingency funds.

Name of Capital Project:	Oak Park Road North Industrial Servicing and Line Relocations (M12 and M13 Feeders)
Capital Project #	11
USofA #	1830, 1835
Project Need and Purpose	Install new feeders from Powerline Road for future demands in this subdivision. This project will also involve relocating the existing M12 and M13 circuits from private property and railway right-of-way to the future road pattern.
Project Scope	Project comprises of installing 55' class 2 poles with 2 circuits, guying and anchors on future roads.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$200,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

7. SCADA AND DISTRIBUTION AUTOMATION

Master SCADA Antenna Pole Replacement

General Description: BPI’s SCADA [Supervisory Control and Data Acquisition] System uses the FreeWave 900 Mhz license free spread spectrum radio system to communication with field devices. The master radio is located at BPI’s Operations centre on a 110’ wooden pole. This pole is approximately 35 years old and needs to be replaced deeming this a non-discretionary project.

Name of Capital Project	Master SCADA Antenna Pole Replacement
Capital Project #	12
USofA #	1835
Project Need & Purpose	The master SCADA antenna pole is needed to communicate with BPI’s automated field devices. The 110’ pole supports the omni

	directional antenna, the coaxial cable, and provides radio coverage to a large portion of BPI’s distribution territory.
Project Scope	Determine whether to replace the pole with a similar wooden pole or an antenna tower. Determine location for new pole/tower. The existing antenna needs to remain in service until the new pole/tower is put into service. RFQ for equipment procurement. Install and test radio system.
Cost-benefit analysis, as applicable	A SCADA radio network with no recurring monthly costs is less expensive that a fibre optic network to every field device. To maintain the existing radio network this master antenna must be replaced as the wooden pole it at the end of life.
Starting Date	2014 Q2
Forecasted Costs	$25,000
Who performed the work [in-house vs. contracted]	In-house/contracted
Procurement method where work was contracted	RFQ

Automated Reclosers

General Description: BPI has two automated reclosers installed at the distribution territory limits where Brant Count Power is embedded. These reclosers isolate downstream faults and provide real time data to BPI SCADA system. The fault isolation minimizes the effects of an outage to upstream BPI customers. Without these reclosers a permanent fault in the embedded utilities territory would not only affect Brant County customers but hundreds of BPI customers as well. BPI intends to use a similar strategy and install additional automated reclosers to feeders supplying only BPI customers.

Name of Capital Project	Automated Reclosers
Capital Project #	13
USofA #	1835
Project Need & Purpose	Improve customer reliability. The recloser will be installed at the mid-way point of a feeder. The recloser will automatically sense downstream faults and isolate/sectionalize the line as required. Upstream customers between

	the feeder breaker and the recloser will not experience an outage as they would have without the recloser in the event of a permanent fault. Outage time to our customers will be reduced. The recloser will be connected to BPI's SCADA and will provide real time voltage, current, real and reactive power and power quality information that would not be available otherwise.
Project Scope	Determine the feeder with lower than desirable reliability indicators. Establish the location for the recloser and coordinate the design with Engineering. Complete protection study to determine protection settings of the recloser. BPI crews install the recloser. SCADA radio install, configure and test. Update SCADA system with new DNP data from the recloser. Update SCADA Worldview HMI with new screen for recloser monitoring/control. Test controls from SCADA.
Cost-benefit analysis, as applicable	Minimize outage time and increased reliability is a benefit to the customer. Industrial and Commercial customers will save money if BPI minimizes process downtime. BPI reliability indices will improve. The recloser fault sensing capabilities will be a time saver for Operations locating a fault on the feeder.
Starting Date	Order equipment in 2014 Q1, install in Q3
Forecasted Costs	$85,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Radios for Reclosers

Name of Capital Project	Radios for Reclosers
Capital Project #	14
USofA #	1835
Project Need & Purpose	BPI's SCADA [Supervisory Control and Data Acquisition] System uses the FreeWave 900 Mhz license free spread spectrum radio system

	to communication with field devices. In order to connect an automated recloser to BPI's SCADA system a SCADA radio must be installed in the recloser controller. The radio communicates real time data from the recloser such as; recloser status (open/close), control, voltage, current, kw, kVA etc.
Project Scope	Purchase a FreeWave SCADA radio, upload the radio settings, installed the radio in the recloser controller cabinet, and install the coaxial cable and antenna on the pole. Once the equipment is installed the radio link strength is verified using software from the vendor. If the link is weak the antenna is adjusted.
Cost-benefit analysis, as applicable	Minimize outage time and increased reliability is a benefit to the customer. Industrial and Commercial customers will save money if BPI minimizes process downtime. BPI reliability indices will improve. The recloser fault sensing capabilities will be a time saver for Operations locating a fault on the feeder.
Starting Date	Order radios in Q1, install in Q3.
Forecasted Costs	$7,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Work Station and Large Screen for Operations Command Centre

Name of Capital Project	Work Station and Large Screen for Operations Command Centre
Capital Project #	15
USofA #	1835
Project Need & Purpose	BPI Operations utilizes a paper map (pin board) to represent the status of the distribution system. SCADA improvements will allow for a real-time model with connectivity of BPI's distribution system. This model can be displayed on a large screen to replace the pin board.
Project Scope	The SCADA model will also provide Operations with a real-time view of the

	distribution system on their laptop in a mobile situation. Presently switching after hours is noted down and the pin board is not updated until the day after.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$5,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Faulted Indicators

General Description: BPI currently has two sets of overhead faulted circuit indicators from two vendors installed as a pilot project. Both types of fault indicators have the ability to connect and report to BPI's SCADA system. Based on performance BPI will select one type and being to replace all of the existing overhead fault indicators in the distribution system.

Name of Capital Project	Faulted Indicators
Capital Project #	16
USofA #	1835
Project Need & Purpose	BPI has older manual style overhead fault indicators located throughout the distribution system. Each distribution feeder has a key set of indicators near the halfway point of the feeder. If a feeder lockouts out due to a power outage Operations will drive to location of the fault indicator to determine if the fault is upstream of downstream of the fault indicator. Once they determine the direction of the fault they begin to patrol the lines. Fault indicator technology has advanced in recent years. Fault indicators are now able to communicate through SCADA, provide real time voltage and current readings and contain fault sensing logic that discerns between temporary and permanent faults. Fault indicators from certain manufacturers allow for integration of non-vendor specific SCADA radios. Connecting fault indicators to SCADA will decrease response time from

	Operations and provide improved customer service.
Project Scope	Three locations will be upgraded to new SCADA connected fault indicators. Install SCADA radios, configure and test. Update SCADA Worldview HMI with new fault indicator locations and real time values. Remove old style fault indicators
Cost-benefit analysis, as applicable	SCADA connected fault indicators will decrease response time from Operations which improves customer service. The fault indicators will provide real time voltage and current data that would only be available otherwise through a more expensive automated switch or recloser. Utilizing the existing SCADA radio network eliminates the need for recurring costs that would be found using other communications means (cellular, leased line, fibre, etc.)
Starting Date	Order fault indicators in 2014 Q1, install in Q2.
Forecasted Costs	$5,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Repeater Radio Installation

General Description: BPI's master SCADA radio antenna is located at BPI's Operations centre. The master SCADA antenna provides communication to a large area of BPI's distribution system, however; there are areas of the distribution system where the master radio is not able to communicate with due to the topology of the City. The SCADA repeater radio will extend the radio network providing communications to all of BPI's distribution system and allowing BPI to install additional SCADA field devices on the radio network.

Name of Capital Project:	Repeater Radio Installation
Capital Project #	17
USofA #	1835

Project Need & Purpose:	Expansion of BPI’s SCADA radio network. Installation of a repeater radio at the Brantford General Hospital will extend the SCADA radio network across the entire City of Brantford. In current state of BPI’s radio network there are radio communications issues due to seasonal change (foliage, tree growth, etc.) and other radio interference that is not controlled by BPI (i.e. cell tower, new building construction, etc.) Approval from the hospital still required to install radio and antenna with BPI’s existing two way radio equipment.
Project Scope	Contractor to install and test the antenna on the mask at the hospital. Configure repeator radio settings and test using head end radio software.
Cost-benefit analysis, as applicable	Expanding the SCADA radio network is a less expensive option than the alternative of installing fibre optic cable to SCADA devices across BPI’s distribution system. There are no recurring costs for radio communications.
Starting dates and in-service dates	Installation is based on approval process time from the hospital; planning for Q2 installation.
Forecasted Costs	$5,000
Who performed the work [in-house vs. contracted]	contracted
Procurement method where work was contracted	RFQ

Multispeak Add On (Survalent)

Name of Capital Project	Multispeak Add On (Survalent)
Capital Project #	18
USofA #	1835
Project Need & Purpose	Survalent’s Multispeak is a specification designed to standardized integration of software and database applications. BPI's SCADA has the ability to be integrated with other software programs and databases. Multispeak will allow BPI to update the SCADA map more efficiently. Today, GIS, SCADA, and the DESS analysis software are all updated separately. Multispeak will allow for SCADA updates to be completed automatically. A Multispeak connection will also provide data to SCADA from the smart

	meter ODS.
Project Scope	Purchase and enable Multispeak in the SCADA system. Configure the multispeak parameters and test the import.
Cost-benefit analysis, as applicable	Today, GIS, SCADA, and the DESS analysis software are all updated separately and manually. Multispeak will save a considerable amount of time in maintaining the SCADA model.
Starting dates and in-service dates	2014 Q3
Forecasted Costs	$18,000
Who performed the work [in-house vs. contracted]	In-house/contracted
Procurement method where work was contracted	Single source from SCADA vendor (Survalent)

Emergency SCADA Equipment Replacement

Name of Capital Project	Emergency SCADA Equipment Replacement
Capital Project #	19
USofA #	1835
Project Need & Purpose	BPI's SCADA system contains several components such as computer servers, communication systems (radio, Ethernet, fibre) and automated field devices. Failure of any of these systems or devices will require immediate replacement.
Project Scope	Replacement of SCADA equipment due to failure
Cost-benefit analysis, as applicable	Although BPI's SCADA system network has built in redundancy a major equipment failure could cause the SCADA system to go offline. Without SCADA, manual switching and monitoring is required by BPI personnel. A SCADA field device failure could lead to manual switching in the field which in turn could add to customer outage time and increased costs to BPI.
Starting dates and in-service dates	2014
Forecasted Costs	$50,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

8. CAPACITOR STUDY / INSTALLATION OF LINE BANKS

General Description: At the time of building the PMTS in 2005, the IESO wanted BPI to install capacitor banks at the Transformer Station to ensure that the Power Factor was not below 90%. A study was done by BPI's consultant to determine if the capacitor installation could be delayed without compromising the power factor requirements, allowing BPI to defer the substantial investment on Transformer Station capacitors. The study indicated that there was no immediate need for the capacitors and they could possibly be delayed to 2015. BPI decided to perform this study again for completion in 2013 to see if the capacitors were required in 2015 or they could be delayed again. If BPI does need the capacitors in 2015, there will be a need to start this project as early as possible because of the long lead time required for design, procurement, installation and administrative & financial coordination with various stakeholders including Brant County Power, IESO and Hydro One. In addition, this study would review the distribution system as a whole for capacitors for three main reasons:

- The distribution capacitors might help in maintaining the power factor at the Transformer Station, hence further deferring the need for TS Capacitors. The distribution capacitors are much cheaper than the TS capacitors.
- Distribution capacitors will help maintain the voltage profile at the tail ends of especially the long feeders, hence improving the power quality to customers.
- There is potential for increased load demand in the east end of the City as this is the area of BPI's distribution territory with lands available for development. To accommodate this potential increase demand in this east end corridor, BPI must bring supply from the Powerline Transformer Station which is approximately 10 km away. The capacitor banks will provide additional capacity by maintaining the proper voltage on the feeders.

Name of Capital Project	BPI Powerline Municipal Transformer Station 27.6 kV Capacitor & Reactive Support & Capacitor Banks Installation - 27.6 kV Distribution System
Capital Project #	20
USofA #	1835

Project Need & Purpose	**Study Report** - This specialized study is required to plan the installation of capacitor banks at the Powerline Municipal Transformer Station and the Distribution Feeders on a timely basis in order to avoid possible penalties from IESO and Hydro One if the Power Factor falls below 90% at the Transformer Station. The installation would also provide additional capacity on the Distribution System to meet new customer loads. The study will also make recommendations to maintain proper voltage at the Distribution Feeders' tail ends in order to maintain power quality as per Distribution System Code requirements. BPI is obligated by CSA to maintain a certain voltage range at a customer connection point.
Project Scope	Capacitor Banks Installation - Installation of pole mounted capacitor banks at locations determined by the capacitor study.
Cost-benefit analysis, as applicable	The alternative to distributed capacitor banks is to build a 2nd Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to installing capacitor banks in the distribution system. The difference in budget forecast year to year is to cover price escalation (equipment, labour.)
Starting dates and in-service dates	Capacitor Line Bank Installations: To be ordered in 2014 Q1 and installed in Q3 (same for 2015-2017 - 3 banks per year). If study recommends 8 banks, then the project will be completed in 2016.
Forecasted Costs	$70,000
Who performed the work [in-house vs. contracted]	Contracted and in-house.
Procurement method where work was contracted	Study: Single source approved by BPI board Installation: RFQ (equipment procurement)

9. CONVERSION OF LINES FROM 4 AND 8 KV TO 27 KV SYSTEM -

Name of Capital Project:	Projects to be determined based on remaining townhomes serviced by 4 kV voltage levels

Capital Project #	21
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	High priority from Asset Management Program to reduce / mitigate asset related risk. Other than transformers and primary cables all other assets are customer owned and conversion requires ownership transfer agreements. This agreement with customer expected in 2014.
Project Scope	Replace 4kV assets with 27.6kV assets, mainly transformers and primary cables. Replace submersible transformers with padmount with some structure relocations.
Cost-benefit analysis, as applicable	
Starting Date	2014
Forecasted Costs	$163,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

Name of Capital Project:	Ownership transfers - Primary services and older 27.6kV Townhome sites
Capital Project #	22
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	This project was undertaken as a result of changes to the Conditions of Service to allow ownership transfer of existing customer owned electrical assets (primary services for Industrial/Commercial customers and all electrical services on private properties in Townhome/Condominiums.)
Project Scope	The project involved ownership transfer agreements with the residents of condominiums/townhomes and owners of commercial/industrial sites, and subsequent transfer of customer owned (mainly secondary and primary cables) to BPI do the planned upgrades as well as replace existing transformers and support infrastructure.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$212,000

Capital Contribution	
Who performed the work [in-house vs. contracted]	In-house/contracted
Procurement method where work was contracted	If by outside contractors, through general line contract through competitive bidding process

10. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS - ASSET MANAGEMENT SYSTEM

General Description: Annual rebuilds of existing lines and equipment discretionary projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers.

Annual rebuild requirements are identified through BPI's asset management program.

Name of Capital Project	General Yearly Rebuilds - Dalhousie Street (Clarence to Stanley)
Capital Project #	23
USofA #	1830,1835,1840, 1845
Project Need & Purpose	Annual rebuilds of existing lines and equipment
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$1,411,750
Capital Contributions	
Who performed the work [in-house vs. contracted]	Contracted/in-house
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

11. ASSET MANAGEMENT CONSULTANCY & SOFTWARE

General Description: In 2014, BPI plans to review the scope of the program, develop modules for integration of outage data and develop a framework for recording the historical data for assets in the GIS. BPI will also continue to explore linking of Daffron and GIS databases in light of the recommendations from the System Integration Study.

Name of Capital Project	Asset Management Consultancy and Software
Capital Project #	24
USofA #	1925
Project Need & Purpose	In the course of the 2008 rate application, BPI committed to investigate Asset Management after identifying an internal need for a risk focused approach to asset management and to develop a sustainable long term program to better manage our assets and better inform the capital plan and budgets for timely asset replacement needs.
Project Scope	The scope covers all activities outlined in the 5-year asset management plan involving consultancy work and supervision by UEM, GIS related upgrades and new software installation by Intergraph (GIS vendor) and UEM as well as individual data collection, assimilation, storage and processing by BPI staff and City IT Services. This includes but is not limited to modifying parameters of gap analysis, model data collection. The priority for 2014 is the development of the framework and to maintain historical data in the GIS and implement; and develop a module to incorporate outage data to the asset risk model.
Cost-benefit analysis, as applicable	The alternate to having a consultant with expertise in the field and working with BPI staff and existing systems, was to purchase an expensive off-the-shelf software as well as paying to modify it and integrate with the existing systems and business processes. This would be far more costly, time consuming and resource intensive.
Starting Date	2014
Forecasted Cost	$100,000
Who performed the work [in-house vs. contracted]	The work will primarily be performed by BPI staff in consultation with UEM as well GIS related upgrades by the vendor (Intergraph). BPI will enter into single source agreements with UEM annually based on the performance of the previous years and work by Intergraph will be through the service level agreement with them to support the existing GIS platform
Procurement method where work was contracted	Sole source provider – UEM as approved by the Board of Directors

12. SYSTEMS INSTALLATIONs AND UPDATES PROJECTS – VARIOUS

General Description: The Systems Integration Study that BPI has undertaken in 2013 will identify a series of systems integration and upgrade projects required over a three- and/or five year period to fulfill BPI's objective of leveraging technology to achieve productivity improvements. Examples of such potential projects include upgrade of the Customer Information System and installation of an outage management system. As the Systems Integration Study has not been completed, specific future projects have not been identified. The purpose of these budget amounts, however, is to reserve capital plan dollars for such projects.

Name of Capital Project	Systems Installations and Updates
Capital Project #	25
USofA #	1925
Project Need & Purpose	System Integration Upgrades
Project Scope	BPI initiated a system integration study to identify system integration deficiencies and other opportunities to leverage technology to achieve productivity gains. The annual amounts represent a provision to fund the specific priority projects to be identified in the System Integration Study recommendations.
Cost-benefit analysis, as applicable	Specific project business cases will be assessed as recommended projects are evaluated and selected for implementation.
Starting Date	2014
Forecasted Cost	$500,000
Who performed the work [in-house vs. contracted]	Implementation of new systems and system upgrades will be a hybrid of in-house and contracted resources
Procurement method where work was contracted	Competitive Bidding Process

13. ANNUAL DESKTOP AND LAPTOP COMPUTER REPLACEMENTS

General Description: Annual replacement of desktop personal computers and laptops. Such equipment is replaced on a three-year cycle with an estimated 15 computers replaced per year at an estimated cost of $1,500 per year

Name of Capital Project	Computer Replacement
Capital Project #	26
USofA #	1980
Project Need & Purpose	Replace aging hardware and software.
Project Scope	Fifteen personal computers and laptops will be replaced each year
Cost-benefit analysis, as applicable	N/A
Starting Date:	2014
Forecasted Costs	$22,500
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Competitive bidding process for equipment hardware

14. METERING

General Description: The Meters and Instrument Transformer Capital Budget Pool are nondiscretionary projects and consist of:

- Replacement of meters that have failed; and
- Installation of new meters to service new customer connections

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	27
USofA #	1860
Project Need & Purpose	These meters and, where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 400 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$215,250
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

15. REPLACEMENT OF VEHICLES

General Description: BPI assesses all vehicle replacement on a case-by-case basis to determine the useful life of the vehicle while maintaining acceptable safety standards. There are discretionary but priority projects with a minimum guideline to replace light vehicles after 7 years and heavy vehicles after 10 years.

Name of Capital Project	Replacement of Vehicles
Capital Project #	28
USofA #	1930
Project Need & Purpose	Replace 3 light vehicles with the same or similar vehicles due to excessive mileage and/or expiry of service life: ➢ 15 year old pick-up truck ➢ 12 year old van ➢ 10 year old van
Project Scope	Procurement of vehicles is in compliance with BPI's purchasing policy. BPI considers age and condition of vehicles plus recommendations from a consultant and repair service providers and opinion of users when making fleet replacement decisions.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$150,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender for equipment

16. TOOL REPLACEMENTS

General Description: In addition to replacement of tools and equipment resulting from normal wear, tools and equipment are replaced to meet health and safety requirements; example of such replacements include new safety harnesses and fall arrest devices, fibreglass sticks and gas detectors.

Name of Capital Project	Tool Replacements
Capital Project #	29
USofA #	1940

Project Need & Purpose	Replacement of tools and equipment resulting from normal wear, tools and equipment are replaced to meet health and safety requirements.
Project Scope	Tools and equipment are replaced to meet health and safety requirements; example of such replacements includes new safety harnesses and fall arrest devices, fibreglass sticks and gas detectors.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
Forecasted Costs	$25,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender for equipment

2015 CAPITAL PLAN

1. NEW LINES & EQUIPMENT

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Services (Roll ins)
Capital Project #	1
USofA #	1855
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Roll-ins comprising mainly of residential customer connections
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2015
Forecasted Costs	$121,275
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Line Extensions
Capital Project #	2
USofA #	1830, 1835
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Overhead portions of mostly general service customer connections and pole lines
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2015
Forecasted Costs	$292,163
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Underground Line Extensions
Capital Project #	3
USofA#	1840
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Underground portions of mostly general

	service customer connections including cables and ducts
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting date	2015
Forecasted Costs	$308,700
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Pole mount transformers for connection to residential and general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2015
Forecasted Costs	$49,613
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	Underground Transformers
Capital Project #	5
USofA #	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2015
Forecasted Costs	$396,900
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

2. POWERLINE FEEDER UPGRADES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Powerline Feeder upgrades – Greenfield Road to Brantwood Park Road - Phase 7
USofA #	6
Capital Project #	1835, 1840
Project Need and Purpose	The project comprises of replacing existing poles to cover approx. 8km length of the circuit extending from Powerline Municipal Transformer Station to the North-East end of the city.
Project Scope:	The project comprises of replacing existing poles to cover approx. 8km length of the circuit extending from Powerline Municipal Transformer Station (MTS) to the North-East end of the city. The existing feeder (including Brant County Power owned circuit feeder) will be upgraded to 556Al standard, plus 2 new feeders will be added for future loading needs. This involved re-routing some of the poles from behind homes on private property to the front of the homes for ease of construction and future maintenance and negotiating land easements with property owners as well. The project is being carried out in phases each year and each phase is identified and treated as a separate project. The expected completion is in 2016.
# of Customer Attachments	N/A
Load	N/A
Cost-benefit analysis, as applicable	The alternate to extending this feeder was to build a 2nd Transformer Station (after Powerline MTS) in the North-East end of the City. The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline MTS which has the capacity to cater to the existing and future loading needs.
Starting Date	2015
Forecasted Costs	$378,000

Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Competitive bidding process

3. NEW SUBDIVISIONS AND TOWNHOMES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Wynfield West – Stage 5
Capital Project #	7
USofA #	1840, 1845
Project Need and Purpose	Estimated connection of 150 subdivision units and 50 townhome units – based on historical development. We have not been provided specifics by the developer.
Project Scope	The project comprises of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure.
Load	Estimated as 730 kwh per lot per month
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$491,825
Who performed the work [in-house vs. contracted]	Majority of the work is performed by building contractors as sub to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

4. CITY/MINISTRY OF TRANSPORTATION RELOCATIONS

General Description: See 2014 Capital Projects.

Name of Capital Project:	City /Ministry of Transportation Relocations
Capital Project #	8
USofA #	1835, 1840
Project Need and Purpose	Relocation of overhead lines resulting from municipal or provincial road infrastructure projects.

Project Scope	It is often impossible to forecast what projects will require any relocation work because the final road designs are not finalized at the time when we submit our budget. Add to that, the City's road construction program can add or subtract streets at any time.
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$55,125
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Tender

Name of Capital Project:	Shellard Lane (West city limits to Colborne West) - Relocation
Capital Project #	9
USofA #	1835
Project Need and Purpose	The City is widening the road and installing a 3m wide walking/bicycle path which requires relocating the existing pole line.
Project Scope	Install new poles and transfer existing wires to new poles.
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$400,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	Colborne St. (Downtown relocations) Clarence St. to Brant. Ave
Capital Project #	10
USofA #	1840
Project Need and Purpose	There may be a need to relocate existing plant because of conflict with the proposed road design.

Project Scope	Relocation of existing plant is built into the budget based on anticipated road improvements to be managed by the City of Brantford. However, the final road designs are not finalized at the time when we submit our budget.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$100,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

5. DALHOUSIE ST. – DOWNTOWN – NEW BUILD – PHASE 2 – PROJECT COORDINATION AND DESIGN

Name of Capital Project:	Dalhousie St. (downtown relocations) Clarence St. to Brant Ave.
Capital Project #	11
USofA #	1840,1845
Project Need and Purpose	The City is reconstructing the road and installing new infrastructure. BPI will install new plant to replace the aging infrastructure with the capability to supply future demands. There may be a need to relocate existing plant because of conflict with the proposed road design.
Project Scope	BPI will be installing new vaults, duct banks and cables in three blocks (Market to Bridge) at the same time as the road construction (2016). BPI will also relocate existing plant at the same time. Project coordination and design will occur in 2014 and 2015.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	Start design/coordination in 2014, continue in 2015 and construction in 2016.
Forecasted Costs	$25,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

6. OAK PARK ROAD NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS [M12 and M13 FEEDERS]

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Oak Park Road North Industrial Servicing and Line Relocations (M12 and M13 Feeders)
Capital Project #	12
USofA #	1830, 1835
Project Need and Purpose	Install new feeders from Powerline Road for future demands in this subdivision. This project will also involve relocating the existing M12 and M13 circuits from private property and railway right-of-way to the future road pattern.
Project Scope	Project comprises of installing 55' class 2 poles with 2 circuits, guying and anchors on future roads.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$200,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

7. SCADA AND DISTRIBUTION AUTOMATION

General Description: Please refer to 2014 Capital Plan.

Automated Reclosers

Name of Capital Project	Automated Reclosers
Capital Project #	13
USofA #	1835
Project Need & Purpose	Improve customer reliability. The recloser will be installed at the mid-way point of a feeder. The recloser will automatically sense downstream faults and isolate/sectionalize the line as required. Upstream customers between the feeder breaker and the recloser will not experience an outage as they would have without the recloser in the event of a permanent fault. Outage time to our customers

	will be reduced. The recloser will be connected to BPI's SCADA and will provide real time voltage, current, real and reactive power and power quality information that would not be available otherwise.
Project Scope	Determine the feeder with lower than desirable reliability indicators. Establish the location for the recloser and coordinate the design with Engineering. Complete protection study to determine protection settings of the recloser. BPI crews install the recloser. SCADA radio install, configure and test. Update SCADA system with new DNP data from the recloser. Update SCADA Worldview HMI with new screen for recloser monitoring/control. Test controls from SCADA.
Cost-benefit analysis, as applicable	Minimize outage time and increased reliability is a benefit to the customer. Industrial and Commercial customers will save money if BPI minimizes process downtime. BPI reliability indices will improve. The recloser fault sensing capabilities will be a time saver for Operations locating a fault on the feeder.
Starting Date	Order equipment in 2015 Q1, install in Q3
Forecasted Costs	$85,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Radios for Reclosers

Name of Capital Project	Radios for Reclosers
Capital Project #	14
USofA #	1835
Project Need & Purpose	BPI’s SCADA [Supervisory Control and Data Acquisition] System uses the FreeWave 900 Mhz license free spread spectrum radio system to communication with field devices. In order to connect an automated recloser to BPI’s SCADA system a SCADA radio must be installed in the recloser controller. The radio communicates real time data from the recloser

	such as; recloser status (open/close), control, voltage, current, kw, kVA etc.
Project Scope	Purchase a FreeWave SCADA radio, upload the radio settings, installed the radio in the recloser controller cabinet, and install the coaxial cable and antenna on the pole. Once the equipment is installed the radio link strength is verified using software from the vendor. If the link is weak the antenna is adjusted.
Cost-benefit analysis, as applicable	Minimize outage time and increased reliability is a benefit to the customer. Industrial and Commercial customers will save money if BPI minimizes process downtime. BPI reliability indices will improve. The recloser fault sensing capabilities will be a time saver for Operations locating a fault on the feeder.
Starting Date	Order radios in 2015 Q1, install in Q3.
Forecasted Costs	$7,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Faulted Indicators

Name of Capital Project	Faulted Indicators
Capital Project #	15
USofA #	1835
Project Need & Purpose	BPI has older manual style overhead fault indicators located throughout the distribution system. Each distribution feeder has a key set of indicators near the halfway point of the feeder. If a feeder lockouts out due to a power outage Operations will drive to location of the fault indicator to determine if the fault is upstream of downstream of the fault indicator. Once they determine the direction of the fault they begin to patrol the lines. Fault indicator technology has advanced in recent years. Fault indicators are now able to

	communicate through SCADA, provide real time voltage and current readings and contain fault sensing logic that discerns between temporary and permanent faults. Fault indicators from certain manufacturers allow for integration of non-vendor specific SCADA radios. Connecting fault indicators to SCADA will decrease response time from Operations and provide improved customer service.
Project Scope	Three locations will be upgraded to new SCADA connected fault indicators. Install SCADA radios, configure and test. Update SCADA Worldview HMI with new fault indicator locations and real time values. Remove old style fault indicators
Cost-benefit analysis, as applicable	SCADA connected fault indicators will decrease response time from Operations which improves customer service. The fault indicators will provide real time voltage and current data that would only be available otherwise through a more expensive automated switch or recloser. Utilizing the existing SCADA radio network eliminates the need for recurring costs that would be found using other communications means (cellular, leased line, fibre, etc.)
Starting Date	Order fault indicators in 2015 Q1, install in Q2.
Forecasted Costs	$5,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Emergency SCADA Equipment Replacement

Name of Capital Project	Emergency SCADA Equipment Replacement
Capital Project #	16
USofA #	1835
Project Need & Purpose	BPI's SCADA system contains several components such as computer servers, communication systems (radio, Ethernet, fibre) and automated field devices. Failure of any of these systems or devices will require immediate replacement.

Project Scope	Replacement of SCADA equipment due to failure
Cost-benefit analysis, as applicable	Although BPI's SCADA system network has built in redundancy a major equipment failure could cause the SCADA system to go offline. Without SCADA, manual switching and monitoring is required by BPI personnel. A SCADA field device failure could lead to manual switching in the field which in turn could add to customer outage time and increased costs to BPI.
Starting dates and in-service dates	2015
Forecasted Costs	$50,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

8. INSTALLATION OF LINE BANKS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	BPI Powerline Municipal Transformer Station 27.6 kV Capacitor & Reactive Support & Capacitor Banks Installation - 27.6 kV Distribution System
Capital Project #	17
USofA #	1835
Project Need & Purpose	**Study Report** - This specialized study is required to plan the installation of capacitor banks at the Powerline Municipal Transformer Station and the Distribution Feeders on a timely basis in order to avoid possible penalties from IESO and Hydro One if the Power Factor falls below 90% at the Transformer Station. The installation would also provide additional capacity on the Distribution System to meet new customer loads. The study will also make recommendations to maintain proper voltage at the Distribution Feeders' tail ends in order to maintain power quality as per Distribution System Code requirements. BPI is obligated by CSA to maintain a certain voltage range at a customer connection point.

Project Scope	Installation of pole mounted capacitor banks at locations determined by the capacitor study.
Cost-benefit analysis, as applicable	The alternative to distributed capacitor banks is to build a 2nd Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to installing capacitor banks in the distribution system. The difference in budget forecast year to year is to cover price escalation (equipment, labour.)
Starting dates and in-service dates	Installations: To be ordered in 2014 Q1 and installed in Q3 (same for 2015-2017 - 3 banks per year). If study recommends 8 banks, then the project will be completed in 2016.
Forecasted Costs	$75,000
Who performed the work [in-house vs. contracted]	Contracted and in-house.
Procurement method where work was contracted	RFQ (equipment procurement)

9. INSTALLATION OF STATION CAPACITOR BANKS AT POWERLINE MTS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Station Cap Banks at Powerline Municipal TS
Capital Project #	18
USofA #	1815
Project Need & Purpose	Installation of a capacitor bank at the Powerline Municipal Transformer Station may be required to avoid possible penalties from IESO and Hydro One if the Power Factor falls below 90% at the transmission connection point.
Project Scope	The PMTS was built with provisions for a capacitor bank. A consultant would be required to finalize the design for the installation. Equipment would then be procured, installed, commissioned and energized.
Cost-benefit analysis, as applicable	Not applicable
Starting dates and in-service dates	2015
Forecasted Costs	$437,500 (BPI 5/8 share)

Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	RFP

10. CONVERSION OF LINES FROM 4 AND 8 KV TO 27 KV SYSTEM

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Projects to determined based on remaining townhomes serviced by 4 kV voltage levels
Capital Project #	19
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	High priority from Asset Management Program to reduce / mitigate asset related risk.
Project Scope	Replace 4kV assets with 27.6kV assets, mainly transformers and primary cables. Replace submersible transformers with padmount with some structure relocations.
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$153,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

	Ownership transfers - Primary services and older 27.6kV Townhome sites
Capital Project #	20
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	This project was undertaken as a result of changes to the Conditions of Service to allow ownership transfer of existing customer owned electrical assets (primary services for Industrial/Commercial customers and all electrical services on private properties in Townhome/Condominiums.
Project Scope	The project involved ownership transfer agreements with the residents of condominiums/townhomes and owners of commercial/industrial sites, and subsequent transfer of customer owned (mainly secondary and primary cables) to BPI do the planned upgrades as well as replace existing

	transformers and support infrastructure.
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$207,000
Who performed the work [in-house vs. contracted]	In-house/contracted
Procurement method where work was contracted	If by outside contractors, through general line contract through competitive bidding process

11. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS - ASSET MANAGEMENT

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	General Yearly Rebuilds (Farringford Dr / Pusey Blvd, Memorial Dr. /Powerline Rd.,
Capital Project #	21
USofA #	1830, 1835, 1840,1845,1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$1,199,288
Who performed the work [in-house vs. contracted]	Contracted/In-house
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

12. ASSET MANAGEMENT CONSULTANCY & SOFTWARE

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Asset Management Consultancy and Software
Capital Project #	22
USofA #	1925

Project Need & Purpose	In the course of the 2008 rate application, BPI committed to investigate Asset Management after identifying an internal need for a risk focused approach to asset management and to develop a sustainable long term program to better manage our assets and better inform the capital plan and budgets for timely asset replacement needs.
Project Scope	The priority for 2015 is the refinement of asset-life cycle model.
Cost-benefit analysis, as applicable	The alternate to having a consultant with expertise in the field and working with BPI staff and existing systems, was to purchase an expensive off-the-shelf software as well as paying to modify it and integrate with the existing systems and business processes. This would be far more costly, time consuming and resource intensive.
In-service Date	2015
Forecasted Costs	$50,000
Who performed the work [in-house vs. contracted]	The work will primarily be performed by BPI staff in consultation with UEM as well GIS related upgrades by the vendor (Intergraph). BPI will enter into single source agreements with UEM annually based on the performance of the previous years and work by Intergraph will be through the service level agreement with them to support the existing GIS platform
Procurement method where work was contracted	Sole source provider – UEM as approved by the Board of Directors

13. SYSTEMS INSTALLATIONS AND UPDATE PROJECTS – VARIOUS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Systems Installations and Updates
Capital Project #	23
USofA #	1925
Project Need & Purpose	System Integration Upgrades
Project Scope	BPI initiated a system integration study to identify system integration deficiencies and other opportunities to leverage technology to achieve productivity gains. The annual amounts represent a provision to fund the specific priority projects to be identified in the System Integration Study recommendations

Cost-benefit analysis, as applicable	Specific project business cases will be assessed as recommended projects are evaluated and selected for implementation. .
Starting dates and in-service dates	2015
Forecasted Costs	$500,000
Who performed the work [in-house vs. contracted]	Implementation of new systems and system upgrades will be a hybrid of in-house and contracted resources.
Procurement method where work was contracted	Competitive Bidding Process

14. ANNUAL DESKTOP AND LAPTOP COMPUTER REPLACEMENTS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Computer Replacement
Capital Project #	24
USofA #	1980
Project Need & Purpose	Replace aging hardware and software
Project Scope	Fifteen personal computers and laptops will be replaced each year
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2015
Forecasted Costs	$22,500
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	RFQ

15. METERING

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	25
USofA #	1860
Project Need & Purpose	These meters and, where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 400 new locations/meters.

Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$226,010
Who performed the work [in-house vs. contracted]	In-house.
Procurement method where work was contracted	N/A

16. REPLACEMENT OF VEHICLES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Replacement of Vehicles
Capital Project #	26
USofA #	1930
Project Need & Purpose	Replace vehicles with the same or similar vehicles due to excessive mileage and/or expiry of service life. ➢ Replace a 14 year old double bucket truck (15 month delivery term)
Project Scope	Procurement of vehicles is in compliance with BPI's purchasing policy. BPI considers age and condition of vehicles plus recommendations from a consultant and repair service providers and opinion of users when making fleet replacement decisions.
Cost-benefit analysis, as applicable	N/A
Starting Date	2014
In-Service Date	2015
Forecasted Costs	$450,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

17. TOOL REPLACEMENTS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Tool Replacements
Capital Project #	27

USofA #	1940
Project Need & Purpose	Replacement of tools and equipment resulting from normal wear, tools and equipment are replaced to meet health and safety requirements.
Project Scope	Tools and equipment are replaced to meet health and safety requirements; example of such replacements includes new safety harnesses and fall arrest devices, fibreglass sticks and gas detectors.
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
Forecasted Costs	$25,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

2016 CAPITAL PLAN

1. NEW LINES & EQUIPMENT

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Services (Roll ins)
Capital Project #	1
USofA #	1855
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Roll-ins comprising mainly of residential customer connections
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2016
Forecasted Costs	$127,339
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Line Extensions
Capital Project #	2
USofA #	1830, 1835
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Overhead portions of mostly general service customer connections and pole lines
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2016
Forecasted Costs	$306,771
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Underground Line Extensions
Capital Project #	3
USofA#	1840, 1845
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.

Project Scope	Underground portions of mostly general service customer connections including cables and ducts
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting date	2016
Forecasted Costs	$324,135
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Pole mount transformers for connection to residential and general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2016
Forecasted Costs	$52,093
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	Underground Transformers
Capital Project #	5
USofA #	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2016
Forecasted Costs	$416,745
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

2. POWERLINE FEEDER UPGRADES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Powerline Feeder upgrades – Brantwood Park Road to East City Limits) - Phase 8
USofA #	6
Capital Project #	1840, 1845, 1850
Project Need and Purpose	The project comprises of replacing existing poles to cover approx. 8km length of the circuit extending from Powerline Municipal Transformer Station to the North-East end of the city.
Project Scope:	The project comprises of replacing existing poles to cover approx. 8km length of the circuit extending from Powerline Municipal Transformer Station (MTS) to the North-East end of the city. The existing feeder (including Brant County Power owned circuit feeder) will be upgraded to 556Al standard, plus 2 new feeders will be added for future loading needs. This involved re-routing some of the poles from behind homes on private property to the front of the homes for ease of construction and future maintenance and negotiating land easements with property owners as well. The project is being carried out in phases each year and each phase is identified and treated as a separate project. The expected completion is in 2016.
# of Customer Attachments	N/A
Load	N/A
Cost-benefit analysis, as applicable	The alternate to extending this feeder was to build a 2nd Transformer Station (after Powerline MTS) in the North-East end of the City. The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline MTS which has the capacity to cater to the existing and future loading needs.
Starting Date	2016
Forecasted Costs	$396,900
Who performed the work [in-house vs. contracted]	Contracted

Procurement method where work was contracted	Competitive bidding process

3. NEW SUBDIVISIONS AND TOWNHOMES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Wyndfield West – Stage 6
Capital Project #	7
USofA #	1845
Project Need and Purpose	Estimated connection of 150 subdivision units and 50 townhome units – based on historical development. We have not been provided specifics by the developer.
Project Scope	The project comprises of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure.
Load	Estimated as 730 kwh per lot per year
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$516,417
Who performed the work [in-house vs. contracted]	Majority of the work is performed by building contractors as sub to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

4. CITY/MINISTRY OF TRANSPORTATION RELOCATIONS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	City /Ministry of Transportation Relocations
Capital Project #	8
USofA #	1830, 1835
Project Need and Purpose	Relocation of overhead lines resulting from municipal or provincial road infrastructure projects.

Project Scope	It is often impossible to forecast what projects will require any relocation work because the final road designs are not finalized at the time when we submit our budget. Add to that, the City's road construction program can add or subtract streets at any time.
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$57,881
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Tender

5. DALHOUSIE ST. – DOWNTOWN – NEW BUILD - PHASE 3 – CONSTRUCTION

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Dalhousie St. (downtown relocations) Clarence St. to Brant Ave.
Capital Project #	9
USofA #	1840,1845
Project Need and Purpose	The City is reconstructing the road and installing new infrastructure. BPI will install new plant to replace the aging infrastructure with the capability to supply future demands. There may be a need to relocate existing plant because of conflict with the proposed road design.
Project Scope	BPI will be installing new vaults, duct banks and cables in three blocks (Market to Bridge) at the same time as the road construction (2016). BPI will also relocate existing plant at the same time. Project coordination and design will occur in 2014 and 2015.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	Construction in 2016.
Forecasted Costs	$1,500,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Tender

6. OAK PARK ROAD NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS[M12 and M13 FEEDERS]

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Oak Park Road North Industrial Servicing and Line Relocations (M12 and M13 Feeders)
Capital Project #	10
USofA #	1830, 1835
Project Need and Purpose	Install new feeders from Powerline Road for future demands in this subdivision. This project will also involve relocating the existing M12 and M13 circuits from private property and railway right-of-way to the future road pattern.
Project Scope	Project comprises of installing 55' class 2 poles with 2 circuits, guying and anchors on future roads.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$50,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

7. SCADA AND DISTRIBUTION AUTOMATION

General Description: Please refer to 2014 Capital Plan.

Emergency SCADA Equipment Replacement

Name of Capital Project	Emergency SCADA Equipment Replacement
Capital Project #	11
USofA #	1835
Project Need & Purpose	BPI's SCADA system contains several components such as computer servers, communication systems (radio, Ethernet, fibre) and automated field devices. Failure of any of these systems or devices will require immediate replacement.
Project Scope	Replacement of SCADA equipment due to failure
Cost-benefit analysis, as applicable	Although BPI’s SCADA system network has built in redundancy a major equipment failure

	could cause the SCADA system to go offline. Without SCADA, manual switching and monitoring is required by BPI personnel. A SCADA field device failure could lead to manual switching in the field which in turn could add to customer outage time and increased costs to BPI.
Starting dates and in-service dates	2016
Forecasted Costs	$50,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

8. INSTALLATION OF LINE BANKS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	BPI Powerline Municipal Transformer Station 27.6 kV Capacitor & Reactive Support & Capacitor Banks Installation - 27.6 kV Distribution System
Capital Project #	12
USofA #	1835
Project Need & Purpose	As determined by Capacitor Study Report
Project Scope	Installation of pole mounted capacitor banks at locations determined by the capacitor study.
Cost-benefit analysis, as applicable	The alternative to distributed capacitor banks is to build a 2nd Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to installing capacitor banks in the distribution system. The difference in budget forecast year to year is to cover price escalation (equipment, labour.)
Starting dates and in-service dates	Installations: To be ordered in 2014 Q1 and installed in Q3 (same for 2015-2017 - 3 banks per year). If study recommends 8 banks, then the project will be completed in 2016.
Forecasted Costs	$80,000
Who performed the work [in-house vs. contracted]	Contracted and in-house.
Procurement method where work was	RFQ (equipment procurement)

contracted	

9. DOWNTOWN AUTOMATION

General Description: The City of Brantford is planning to rebuild the downtown section of Dalhousie Street in 2016. BPI is taking this opportunity to coordinate with the City and install an automated switching scheme. This switching scheme will be designed to automatically transfer load from different supply points, sectionalize feeder faults, and restore power to as many customer as possible.

Name of Capital Project	Downtown Automation
Capital Project #	13
USofA #	1835
Project Need & Purpose	The downtown automation project will improve reliability to the customer by restoring power automatically in the event of a feeder outage.
Project Scope	Coordinate the design with the City Engineering department. Determine the best communication solution for the automation scheme (wireless, fibre, etc). Complete the design in-house, RFQ for equipment, install, commission, energize.
Cost-benefit analysis, as applicable	Coordinating this project with the City's rebuild plan will be cheaper than if BPI were to wait and install the automation project after the fact. Switch vaults and duct bank design locations can be designed to accommodate the City's power requirements as well as meeting BPI's needs for the automation scheme.
Starting dates and in-service dates	2016 (based on City's plan)
Forecasted Costs	$200,000
Who performed the work [in-house vs. contracted]	contracted
Procurement method where work was contracted	RFP

10. CONVERSION OF LINES FROM 4 AND 8 KV TO 27 KV SYSTEM -

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Projects to determined based on remaining

	townhomes serviced by 4 kV voltage levels
Capital Project #	14
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	High priority from Asset Management Program to reduce / mitigate asset related risk. Other than transformers and primary cables all other assets are customer owned and conversion requires ownership transfer agreements. This agreement with customer expected by 2014.
Project Scope	Replace 4kV assets with 27.6kV assets, mainly transformers and primary cables. Replace submersible transformers with padmount with some structure relocations.
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$139,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

Name of Capital Project:	Shellard Lane(8kv), Gretzky Centre, Kramers Way, Lion's Park, North Park Collegiate, Mt. Pleasant Feed to County, George St. feed to City, Tollgate Rd feed to Tollgate Tech., Cambridge Dr. feed to Russell Reid - (To be completed over 2016 and 2017)
Capital Project #	15
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	High priority from Asset Management Program to reduce / mitigate asset related risk.
Project Scope	Replace 4kV assets with 27.6kV assets, mainly transformers and primary cables. Replace submersible transformers with padmount with some structure relocations.
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$100,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was	Open competitive bidding based on yearly

contracted	approved, pre-qualified contractors.

	Ownership transfers - Primary services and older 27.6kV Townhome sites
Capital Project #	16
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	This project was undertaken as a result of changes to the Conditions of Service to allow ownership transfer of existing customer owned electrical assets (primary services for Industrial/Commercial customers and all electrical services on private properties in Townhome/Condominums.)
Project Scope	The project involved ownership transfer agreements with the residents of condominiums/townhomes and owners of commercial/industrial sites, and subsequent transfer of customer owned (mainly secondary and primary cables) to BPI do the planned upgrades as well as replace existing transformers and support infrastructure.
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$153,000
Who performed the work [in-house vs. contracted]	In-house/contracted
Procurement method where work was contracted	If by outside contractors, through general line contract through competitive bidding process

11. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS - ASSET MANAGEMENT

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	General Yearly Rebuilds North Park, Memorial, Blackfriar, Allensgate Myrtleville
Capital Project #	17
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.

Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$1,159,652
Who performed the work [in-house vs. contracted]	Contracted/in house
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

12. ASSET MANAGEMENT CONSULTANCY & SOFTWARE

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Asset Management Consultancy and Software
Capital Project #	18
USofA #	1925
Project Need & Purpose	Please refer to 2014 Capital Plan
Project Scope	The priority for 2016 is the implementation of a user dashboard to display the health of assets based on the output from the risk model.
Cost-benefit analysis, as applicable	In-house development of tools and methodologies to leverage existing systems is much more cost effective than purchasing an off-the-shelf software and paying to modify it and integrate with the existing systems and business processes. The latter is much more costly, time consuming and resource intensive.
In-service Date	2016
Forecasted Costs	$50,000
Who performed the work [in-house vs. contracted]	The work will primarily be performed by BPI staff in consultation with UEM as well GIS related upgrades by the vendor (Intergraph). BPI will enter into single source agreements with UEM annually based on the performance of the previous years and work by Intergraph will be through the service level agreement with them to support the existing GIS platform
Procurement method where work was contracted	Sole source provider – UEM as approved by the Board of Directors; Integraph service provider for GIS-related upgrades.

13. SYSTEMS INSTALLATIONS AND UPDATE PROJECTS – VARIOUS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Systems Installations and Updates
Capital Project #	19
USofA #	1925
Project Need & Purpose	System Integration Upgrades
Project Scope	BPI initiated a system integration study to identify system integration deficiencies and other opportunities to leverage technology to achieve productivity gains. The annual amounts represent a provision to fund the specific priority projects to be identified in the System Integration Study recommendations.
Cost-benefit analysis, as applicable	Specific project business cases will be assessed as recommended projects are evaluated and selected for implementation.
Starting dates and in-service dates	2016
Forecasted Costs	$500,000
Who performed the work [in-house vs. contracted]	Implementation of new systems and system upgrades will be a hybrid of in-house and contracted resources.
Procurement method where work was contracted	Competitive Bidding Process

14. ANNUAL DESKTOP AND LAPTOP COMPUTER REPLACEMENTS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Computer Replacement
Capital Project #	20
USofA #	1980
Project Need & Purpose	Replace aging hardware and software.
Project Scope	Fifteen personal computers and laptops will be replaced each year
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2016
Forecasted Costs	$22,500
Who performed the work [in-house vs. contracted]	In-house

Procurement method where work was contracted	RFQ

15. METERING

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	21
USofA #	1860
Project Need & Purpose	These meters and, where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 400 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$237,310
Who performed the work [in-house vs. contracted]	In-house.
Procurement method where work was contracted	N/A

16. WHOLESALE METERING

General Description: As a compliance requirement to meet Measurement Canada and IESO requirements, wholesale metering for the BPI delivery points requires re-verification.

Name of Capital Project	Wholesale metering (IESO meter points)
Capital Project #	22
USofA #	1860
Project Need & Purpose	Need to maintain compliance with Measurement Canada (MC) and Independent Electricity System Operator (IESO) requirements for metering of wholesale electricity delivery points.
Project Scope	Renewal and reverification of IESO wholesale electricity delivery points. IESO main meters will be re-verified and IESO alt meters will be replaced.
Cost-benefit analysis, as applicable	N/A

Starting Date	2016
Forecasted Costs	$62,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Labour will be carried out by BPI's Meter Service Provider (MSP). Re-verification of meters will be carried out by BPI's MSP. Alt meters will be procured as per BPI's approved purchasing policy.

17. REPLACEMENT OF VEHICLES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Replacement of Vehicles
Capital Project #	23
USofA #	1930
Project Need & Purpose	Replace vehicles with the same or similar vehicles due to excessive mileage and/or expiry of service life. ➢ Replace a 12 year old tandem rotary boring auger truck – 15 month delivery term.
Project Scope	Procurement of vehicles is in compliance with BPI's purchasing policy. BPI considers age and condition of vehicles plus recommendations from a consultant and repair service providers and opinion of users when making fleet replacement decisions.
Cost-benefit analysis, as applicable	N/A
Starting Date	2015
In-Service Date	2016
Forecasted Costs	$350,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

18. TOOL REPLACEMENTS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Tool Replacements
Capital Project #	24
USofA #	1940
Project Need & Purpose	Replacement of tools and equipment resulting from normal wear, tools and equipment are replaced to meet health and safety requirements.
Project Scope	Tools and equipment are replaced to meet health and safety requirements; example of such replacements includes new safety harnesses and fall arrest devices, fibreglass sticks and gas detectors.
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
Forecasted Costs	$25,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

2017 CAPTIAL PLAN

1. **NEW LINES & EQUIPMENT**

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Services (Roll ins)
Capital Project #	1
USofA #	1855
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Roll-ins comprising mainly of residential customer connections
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2017
Forecasted Costs	$133,706
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Line Extensions
Capital Project #	2
USofA #	1830, 1835
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Overhead portions of mostly general service customer connections and pole lines
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2017
Forecasted Costs	$322,109
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Underground Line Extensions
Capital Project #	3
USofA#	1840, 1845

Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Underground portions of mostly general service customer connections including cables and ducts
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting date	2017
Forecasted Costs	$340,342
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Pole mount transformers for connection to residential and general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2017
Forecasted Costs	$54,698
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	Underground Transformers
Capital Project #	5
USofA #	1850
Project Need and Purpose	To provide secondary services, primary services and overhead and underground transformers to customers.
Project Scope	Padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting Date	2017
Forecasted Costs	$437,582
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was	N/A

contracted	

2. NEW SUBDIVISIONS AND TOWNHOMES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Wyndfield West – Stage 7
Capital Project #	6
USofA #	1840, 1845, 1850
Project Need and Purpose	Estimated connection of 150 subdivision units and 50 townhome units – based on historical development. BPI has not been provided specifics by the developer.
Project Scope	The project comprises of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure.
Load	Estimated as 730 kwh per lot per month
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$542,237
Who performed the work [in-house vs. contracted]	Majority of the work is performed by building contractors as sub to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

3. CITY/MINISTRY OF TRANSPORTATION RELOCATIONS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	City /Ministry of Transportation Relocations
Capital Project #	7
USofA #	1830, 1835
Project Need and Purpose	Relocation of overhead lines resulting from municipal or provincial road infrastructure projects.

Project Scope	It is often impossible to forecast what projects will require any relocation work because the final road designs are not finalized at the time when BPI submits its budget. Add to that, the City's road construction program can add or subtract streets at any time.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$60,775
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Tender

4. OAK PARK ROAD NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS [M12 and M13 FEEDERS]

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Oak Park Road North Industrial Servicing and Line Relocations (M12 and M13 Feeders)
Capital Project #	8
USofA #	1830, 1835
Project Need and Purpose	Install new feeders from Powerline Road for future demands in this subdivision. This project will also involve relocating the existing M12 and M13 circuits from private property and railway right-of-way to the future road pattern.
Project Scope	Project comprises of installing 55' class 2 poles with 2 circuits, guying and anchors on future roads.
Load	N/A
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$50,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

5. SCADA AND DISTRIBUTION AUTOMATION

General Description: Please refer to 2014 Capital Plan.

Automated Reclosers

Name of Capital Project	Automated Reclosers
Capital Project #	9
USofA #	1835
Project Need & Purpose	Improve customer reliability. The recloser will be installed at the mid-way point of a feeder. The recloser will automatically sense downstream faults and isolate/sectionalize the line as required. Upstream customers between the feeder breaker and the recloser will not experience an outage as they would have without the recloser in the event of a permanent fault. Outage time to our customers will be reduced. The recloser will be connected to BPI's SCADA and will provide real time voltage, current, real and reactive power and power quality information that would not be available otherwise.
Project Scope	Determine the feeder with lower than desirable reliability indicators. Establish the location for the recloser and coordinate the design with Engineering. Complete protection study to determine protection settings of the recloser. BPI crews install the recloser. SCADA radio install, configure and test. Update SCADA system with new DNP data from the recloser. Update SCADA Worldview HMI with new screen for recloser monitoring/control. Test controls from SCADA.
Cost-benefit analysis, as applicable	Minimize outage time and increased reliability is a benefit to the customer. Industrial and Commercial customers will save money if BPI minimizes process downtime. BPI reliability indices will improve. The recloser fault sensing capabilities will be a time saver for Operations locating a fault on the feeder.
Starting Date	Order equipment in 2017 Q1, install in Q3
Forecasted Costs	$115,000

Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Radios for Reclosers

Name of Capital Project	Radios for Reclosers
Capital Project #	10
USofA #	1835
Project Need & Purpose	BPI's SCADA [Supervisory Control and Data Acquisition] System uses the FreeWave 900 Mhz license free spread spectrum radio system to communication with field devices. In order to connect an automated recloser to BPI's SCADA system a SCADA radio must be installed in the recloser controller. The radio communicates real time data from the recloser such as; recloser status (open/close), control, voltage, current, kw, kVA etc.
Project Scope	Purchase a FreeWave SCADA radio, upload the radio settings, installed the radio in the recloser controller cabinet, and install the coaxial cable and antenna on the pole. Once the equipment is installed the radio link strength is verified using software from the vendor. If the link is weak the antenna is adjusted.
Cost-benefit analysis, as applicable	Minimize outage time and increased reliability is a benefit to the customer. Industrial and Commercial customers will save money if BPI minimizes process downtime. BPI reliability indices will improve. The recloser fault sensing capabilities will be a time saver for Operations locating a fault on the feeder.
Starting Date	Order radios in 2017 Q1, install in Q3.
Forecasted Costs	$30,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Faulted Indicators

Name of Capital Project	Faulted Indicators
Capital Project #	11
USofA #	1835
Project Need & Purpose	BPI has older manual style overhead fault indicators located throughout the distribution system. Each distribution feeder has a key set of indicators near the halfway point of the feeder. If a feeder lockouts out due to a power outage Operations will drive to location of the fault indicator to determine if the fault is upstream of downstream of the fault indicator. Once they determine the direction of the fault they begin to patrol the lines. Fault indicator technology has advanced in recent years. Fault indicators are now able to communicate through SCADA, provide real time voltage and current readings and contain fault sensing logic that discerns between temporary and permanent faults. Fault indicators from certain manufacturers allow for integration of non-vendor specific SCADA radios. Connecting fault indicators to SCADA will decrease response time from Operations and provide improved customer service.
Project Scope	Three locations will be upgraded to new SCADA connected fault indicators. Install SCADA radios, configure and test. Update SCADA Worldview HMI with new fault indicator locations and real time values. Remove old style fault indicators
Cost-benefit analysis, as applicable	SCADA connected fault indicators will decrease response time from Operations which improves customer service. The fault indicators will provide real time voltage and current data that would only be available otherwise through a more expensive automated switch or recloser. Utilizing the existing SCADA radio network eliminates the need for recurring costs that would be found using other communications means (cellular, leased line,

	fibre, etc.)
Starting Date	Order fault indicators in 2017 Q1, install in Q2.
Forecasted Costs	$25,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Emergency SCADA Equipment Replacement

Name of Capital Project	Emergency SCADA Equipment Replacement
Capital Project #	12
USofA #	1835
Project Need & Purpose	BPI's SCADA system contains several components such as computer servers, communication systems (radio, Ethernet, fibre) and automated field devices. Failure of any of these systems or devices will require immediate replacement.
Project Scope	Replacement of SCADA equipment due to failure
Cost-benefit analysis, as applicable	Although BPI's SCADA system network has built in redundancy a major equipment failure could cause the SCADA system to go offline. Without SCADA, manual switching and monitoring is required by BPI personnel. A SCADA field device failure could lead to manual switching in the field which in turn could add to customer outage time and increased costs to BPI.
Starting dates and in-service dates	2017
Forecasted Costs	$105,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

6. INSTALLATION OF LINE BANKS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	BPI Powerline Municipal Transformer Station 27.6 kV Capacitor & Reactive Support & Capacitor Banks Installation - 27.6 kV Distribution System
Capital Project #	13
USofA #	1835
Project Need & Purpose	As determined by Capacitor Study Report
Project Scope	Installation of pole mounted capacitor banks at locations determined by the capacitor study.
Cost-benefit analysis, as applicable	The alternative to distributed capacitor banks is to build a 2nd Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to installing capacitor banks in the distribution system. The difference in budget forecast year to year is to cover price escalation (equipment, labour.)
Starting dates and in-service dates	Installations: To be ordered in 2014 Q1 and installed in Q3 (same for 2015-2017 - 3 banks per year). If study recommends 8 banks, then the project will be completed in 2016.
Forecasted Costs	$85,000
Who performed the work [in-house vs. contracted]	Contracted and in-house.
Procurement method where work was contracted	RFQ (equipment procurement)

7. CONVERSION OF LINES FROM 4 AND 8 KV TO 27 KV SYSTEM

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project:	Projects to determined based on remaining townhomes serviced by 4 kV voltage levels
Capital Project #	14
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	High priority from Asset Management Program to reduce / mitigate asset related risk.

Project Scope	Replace 4kV assets with 27.6kV assets, mainly transformers and primary cables. Replace submersible transformers with padmount with some structure relocations.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$107,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

Name of Capital Project:	Shellard Lane(8kv), Gretzky Centre, Kramers Way, Lion's Park, North Park Collegiate, Mt. Pleasant Feed to County, George St. feed to City, Tollgate Rd feed to Tollgate Tech., Cambridge Dr feed to Russell Reid – Projects to be completed over 2016 and 2017
Capital Project #	15
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	High priority from Asset Management Program to reduce / mitigate asset related risk.
Project Scope	Replace 4kV assets with 27.6kV assets, mainly transformers and primary cables. Replace submersible transformers with padmount with some structure relocations.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$100,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

	Ownership transfers - Primary services and older 27.6kV Townhome sites
Capital Project #	16
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	This project was undertaken as a result of changes to the Conditions of Service to allow ownership transfer of existing customer owned

	electrical assets (primary services for Industrial/Commercial customers and all electrical services on private properties in Townhome/Condominums.)
Project Scope	The project involved ownership transfer agreements with the residents of condominiums/townhomes and owners of commercial/industrial sites, and subsequent transfer of customer owned (mainly secondary and primary cables) to BPI do the planned upgrades as well as replace existing transformers and support infrastructure.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$209,500
Who performed the work [in-house vs. contracted]	In-house/contracted
Procurement method where work was contracted	If by outside contractors, through general line contract through competitive bidding process

8. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS - ASSET MANAGEMENT

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	General Yearly Rebuilds Forest/Keeler/Marvin, Metcalf Cres, James Ave. /Grey St. Condos., Scarfe Gardens, Dunsdon St. /Sheena Ave.
Capital Project #	17
USofA #	1830, 1835, 1840, 1845, 1845, 1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment are essential, nondiscretionary projects and include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers.
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$1,247,884
Who performed the work [in-house vs.	In-house

contracted]	
Procurement method where work was contracted	N/A

9. ASSET MANAGEMENT CONSULTANCY & SOFTWARE

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Asset Management Consultancy and Software
Capital Project #	18
USofA #	1925
Project Need & Purpose	Please refer to 2014 Capital Plan
Project Scope	The priority for 2017 is sustainable maintenance of the program as well as exploring new opportunities for further development.
Cost-benefit analysis, as applicable	Continuation of the program implementation at a sustained level, is a validation of the success of its development over the years.
Starting dates and in-service dates	2017
Forecasted Costs	$30,000
Who performed the work [in-house vs. contracted]	The work will primarily be performed by BPI staff in consultation with UEM
Procurement method where work was contracted	Sole source provider – UEM as approved by the Board of Directors.

10. SYSTEMS INSTALLATIONS AND UPDATE PROJECTS – VARIOUS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Systems Installations and Updates
Capital Project #	19
USofA #	1925
Project Need & Purpose	System Integration Upgrades
Project Scope	BPI initiated a system integration study to identify system integration deficiencies and other opportunities to leverage technology to achieve productivity gains. The annual amounts represent a provision to fund the specific priority projects to be identified in the System Integration Study recommendations.

Cost-benefit analysis, as applicable	Specific project business cases will be assessed as recommended projects are evaluated and selected for implementation.
Starting dates and in-service dates	2017
Forecasted Costs	$500,000
Who performed the work [in-house vs. contracted]	Implementation of new systems and system upgrades will be a hybrid of in-house and contracted resources.
Procurement method where work was contracted	Competitive Bidding Process

11. ANNUAL DESKTOP AND LAPTOP COMPUTER REPLACEMENTS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Computer Replacement
Capital Project #	20
USofA #	1980
Project Need & Purpose	Replace aging hardware and software.
Project Scope	Fifteen personal computers and laptops will be replaced each year
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2017
Forecasted Costs	$22,500
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	RFQ

12. METERING

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	21
USofA #	1860
Project Need & Purpose	These meters and, where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed.

	Approximately 400 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$249,180
Who performed the work [in-house vs. contracted]	In-house.
Procurement method where work was contracted	N/A

13. WHOLESALE METERING

General Description: Please refer to 2016 Capital Plan.

Name of Capital Project	Wholesale metering (IESO meter points)
Capital Project #	22
USofA #	1860
Project Need & Purpose	Need to maintain compliance with Measurement Canada (MC) and Independent Electricity System Operator (IESO) requirements for metering of wholesale electricity delivery points.
Project Scope	Renewal and reverification of IESO wholesale electricity delivery points. IESO main meters will be re-verified and IESO alt meters will be replaced.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017
Forecasted Costs	$12,000
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Labour will be carried out by BPI's Meter Service Provider (MSP). Re-verification of meters will be carried out by BPI's MSP. Alt meters will be procured as per BPI's approved purchasing policy.

14. REPLACEMENT OF VEHICLES

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Replacement of Vehicles
Capital Project #	23

USofA #	1930
Project Need & Purpose	Replace vehicles with the same or similar vehicles due to excessive mileage and/or expiry of service life. ➢ Replace a 12 year old single bucket truck (with heavy lift capability) – 15 month delivery term ➢ Replace an 11 year old pick-up truck (Starting and in-service date – 2017)
Project Scope	Procurement of vehicles is in compliance with BPI's purchasing policy. BPI considers age and condition of vehicles plus recommendations from a consultant and repair service providers and opinion of users when making fleet replacement decisions.
Cost-benefit analysis, as applicable	N/A
Starting Date	2016
In-Service Date	2017
Forecasted Costs	$350,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

15. TOOL REPLACEMENTS

General Description: Please refer to 2014 Capital Plan.

Name of Capital Project	Tool Replacements
Capital Project #	24
USofA #	1940
Project Need & Purpose	Replacement of tools and equipment resulting from normal wear, tools and equipment are replaced to meet health and safety requirements.
Project Scope	Tools and equipment are replaced to meet health and safety requirements; example of such replacements includes new safety harnesses and fall arrest devices, fibreglass sticks and gas detectors.
Cost-benefit analysis, as applicable	N/A
Starting Date	2017

Forecasted Costs	$25,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

ATTACHMENT I

REFERENCE: 3.0 Staff 11

The full Regression Model is sent separately as an Excel document.

Brantford Power Weather Normal Load Forecast for 2013 Rate Application

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	
Actual kWh Purchases	964,286,210	989,608,990	1,025,654,030	1,022,795,092	1,043,014,997	1,013,423,330	940,830,205	950,759,113	944,902,732	964,379,231		
Predicted kWh Purchases	970,363,655	974,909,760	1,029,456,186	1,019,102,992	1,037,169,727	1,013,507,574	953,893,400	957,649,995	958,893,191	944,707,448	936,688,331	
predicted vs actual	0.6%	-1.5%	0.4%	-0.4%	-0.6%	0.0%	1.4%	0.7%	1.5%			
Change in actual		25,322,780.50	36,045,040.08	(2,858,938.07)	20,219,904.69	(29,591,666.98)	(72,593,124.68)	9,928,907.61	(5,856,380.53)	(195,284.50)	(8,019,116.65)	
% change in actual		3%	4%	0%	2%	-3%	-7%	1%	-1%	-0.021%	-0.849%	
Billed kWh	913,442,956	949,864,834	985,555,339	987,570,495	1,004,831,701	977,884,255	912,366,781	917,169,662	915,803,475	931,554,498	899,549,721	
		36,421,878	35,690,505	2,015,156	17,261,206	-26,947,446	-65,517,474	4,802,881	-1,366,187	15,751,023	-32,004,777	
By Class		4%	4%	0%	2%	-3%	-7%	1%	0%	2%	-3.44%	
Residential												
Customers	31,105	31,707	32,252	32,754	33,237	33,645	33,929	34,219	34,621	34,913	35,364	
kWh	270,806,559	269,489,820	293,232,137	281,767,239	285,310,578	278,923,645	275,417,341	287,357,342	289,048,493	284,844,991	272,082,836	
		-1,316,739	23,742,317	-11,464,898	3,543,339	-6,386,933	-3,506,304	11,940,001	1,691,151	-4,203,502	-12,762,155	
GS<50		0%	9%	-4%	1%	-2%	-1%	4%	1%	-1%	-4%	
Customers	2,428	2,445	2,482	2,549	2,640	2,707	2,700	2,684	2,705	2,729	2,764	
kWh	95,006,443	96,978,252	103,223,115	102,615,621	105,113,198	104,110,563	99,603,717	98,691,975	98,344,763	99,625,182	94,447,805	
		1,971,809	6,244,863	-607,494	2,497,577	-1,002,635	-4,506,846	-911,742	-347,212	1,280,419	-5,177,377	
GS>50		2%	6%	-1%	2%	-1%	-4%	-1%	0%	1%	-5%	
Customers	394	391	392	397	410	405	409	418	421	417	420	
kWh	539,007,863	574,507,768	580,021,347	594,077,901	605,456,649	585,927,516	528,476,684	521,725,747	519,052,260	537,717,579	523,567,859	
kW	1,339,301	1,416,806	1,575,503	1,501,228	1,516,185	1,477,384	1,336,469	1,325,334	1,343,794	1,386,954	1,332,860	
		35,499,905	5,513,579	14,056,554	11,378,748	-19,529,133	-57,450,832	-6,750,937	-2,673,487	18,665,319	-14,149,720	
Large User		7%	1%	2%	2%	-3%	-10%	-1%	-1%	4%	-3%	
Customers	0	0	0	0	0	0	0	0	0	0	0	
kWh	0	0	0	0	0	0	0	0	0	0	0	
kW	0	0	0	0	0	0	0	0	0	0	0	
Sentinels												
Connections	0	0	0	317	569	586	592	605	620	624	635	
kWh	0	0	0	0	0	0	0	480,615	465,459	435,374	443,490	
kW	0	0	0	0	0	0	0	1,470	1,423	1,331	1,356	
Streetlights												
Connections	8,434	8,578	9,048	9,328	9,610	7,540	9,577	9,644	9,981	10,145	10,355	
kWh	6,116,876	6,269,377	6,635,713	6,975,374	7,101,501	7,240,798	7,316,579	7,354,351	7,337,049	7,395,384	7,553,004	
kW	20,270	19,077	20,301	21,299	21,758	22,064	22,380	22,480	24,297	22,533	23,455	
		152,501	366,336	339,661	126,127	139,297	75,781	37,772	-17,302	58,335	157,620	
USL		2%	6%	5%	2%	2%	1%	1%	0%	1%	2%	
Connections	499	508	502	452	438	440	444	445	444	443	437	
kWh	2,505,215	2,619,617	2,443,027	2,134,360	1,849,775	1,681,733	1,552,460	1,559,632	1,555,451	1,535,988	1,454,727	
		114,402	-176,590	-308,667	-284,585	-168,042	-129,273	7,172	-4,181	-19,463	-81,261	
Total of Above		5%	-7%	-13%	-13%	-9%	-8%	0%	0%	-1%	-5%	
Customer/Connections	42,860	43,629	44,676	45,798	46,902	45,322	47,651	48,014	48,792	49,270	49,975	
kWh	913,442,956	949,864,834	985,555,339	987,570,495	1,004,831,701	977,884,255	912,366,781	917,169,662	915,803,475	931,554,498	899,549,721	
kW from applicable classes	1,359,571	1,435,883	1,595,804	1,522,527	1,537,943	1,499,448	1,358,849	1,349,283	1,369,514	1,410,819	1,357,672	
Total from Model												
Customer/Connections	42,860	43,629	44,676	45,798	46,902	45,322	47,651	48,014	48,792	49,270	49,975	
kWh	913,442,956	949,864,834	985,555,339	987,570,495	1,004,831,701	977,884,255	912,366,781	917,169,662	915,803,475	931,554,498	899,549,721	
kW from applicable classes	1,359,571	1,435,883	1,595,804	1,522,527	1,537,943	1,499,448	1,358,849	1,349,283	1,369,514	1,410,819	1,357,672	
Check should all be zero												
Customer/Connections	0	0	0	0	0	0	0	0		0	0	
kWh	0	0	0	0	0	0	0	0		0	0	CDM Amount
kW from applicable classes	0	0	0	0	0	0	0	0		0	0	

	Total Purchases	Heating Degree Days	Cooling Degree Days	Number of Days in	Real Ontario	April	May	October	Negative Impact		Variances (kWh)
Jan-03	87,388,286	815	-	31	125.66	0	0	0	0	*87,115,654*	
Feb-03	79,249,838	699	-	28	125.81	0	0	0	0	*79,605,590*	
Mar-03	81,540,901	581	-	31	125.95	0	0	0	0	*83,487,421*	
Apr-03	74,201,337	373	2	30	126.10	1	0	0	0	*74,244,496*	
May-03	72,603,730	178	-	31	126.24	0	1	0	0	*73,804,393*	
Jun-03	77,278,956	43	53	30	126.39	0	0	0	0	*79,036,762*	
Jul-03	90,974,807	0	118	31	126.54	0	0	0	0	*87,664,080*	
Aug-03	81,817,315	2	128	31	126.68	0	0	0	0	*88,862,233*	
Sep-03	78,164,432	55	24	30	126.83	0	0	0	0	*76,217,699*	
Oct-03	78,072,590	276	-	31	126.98	0	0	1	0	*77,180,125*	
Nov-03	79,241,459	399	-	30	127.12	0	0	0	0	*79,257,661*	
Dec-03	83,752,558	562	-	31	127.27	0	0	0	0	*83,887,542*	
Jan-04	90,837,491	849	-	31	127.53	0	0	0	0	*88,696,313*	
Feb-04	83,093,877	632	-	29	127.80	0	0	0	0	*81,501,753*	
Mar-04	85,032,643	487	-	31	128.06	0	0	0	0	*83,112,371*	
Apr-04	76,314,845	332	-	30	128.32	1	0	0	0	*74,520,681*	
May-04	76,988,030	159	9	31	128.59	0	1	0	0	*75,736,911*	
Jun-04	80,201,463	44	32	30	128.85	0	0	0	0	*77,997,694*	
Jul-04	84,364,755	4	86	31	129.12	0	0	0	0	*85,541,658*	
Aug-04	83,757,960	13	60	31	129.38	0	0	0	0	*82,826,374*	
Sep-04	81,122,721	30	41	30	129.65	0	0	0	0	*79,279,249*	
Oct-04	78,913,063	226	2	31	129.92	0	0	1	0	*78,141,735*	
Nov-04	81,423,641	379	-	30	130.19	0	0	0	0	*80,607,946*	
Dec-04	87,558,513	643	-	31	130.45	0	0	0	0	*86,947,074*	
Jan-05	91,714,412	770	-	31	130.74	0	0	0	0	*89,158,816*	
Feb-05	81,076,815	616	-	28	131.03	0	0	0	0	*81,109,429*	
Mar-05	87,176,799	609	-	31	131.33	0	0	0	0	*86,856,670*	
Apr-05	75,263,673	307	-	30	131.62	1	0	0	0	*75,911,489*	
May-05	78,470,578	189	1	31	131.91	0	1	0	0	*77,162,840*	
Jun-05	92,848,969	9	146	30	132.20	0	0	0	0	*92,126,283*	
Jul-05	94,845,399	-	189	31	132.50	0	0	0	0	*98,807,698*	
Aug-05	93,143,275	0	141	31	132.79	0	0	0	0	*93,581,484*	
Sep-05	80,842,300	23	52	30	133.09	0	0	0	0	*82,251,943*	
Oct-05	79,268,420	220	8	31	133.38	0	0	1	0	*80,612,191*	
Nov-05	82,590,728	388	-	30	133.68	0	0	0	0	*82,659,017*	
Dec-05	88,412,660	665	-	31	133.98	0	0	0	0	*89,218,326*	
Jan-06	88,782,670	552	-	31	134.25	0	0	0	17,090	*87,415,490*	
Feb-06	82,652,726	604	-	28	134.53	0	0	0	34,181	*82,590,861*	
Mar-06	87,287,263	517	-	31	134.81	0	0	0	51,271	*86,922,608*	
Apr-06	76,130,011	293	-	30	135.08	1	0	0	68,362	*77,131,853*	
May-06	81,448,519	137	26	31	135.36	0	1	0	85,452	*80,460,775*	
Jun-06	86,666,222	20	74	30	135.64	0	0	0	102,543	*85,336,068*	
Jul-06	96,205,464	-	167	31	135.92	0	0	0	119,633	*97,486,366*	
Aug-06	91,965,539	4	102	31	136.20	0	0	0	136,723	*90,218,253*	
Sep-06	78,075,371	81	13	30	136.48	0	0	0	153,814	*79,639,066*	
Oct-06	81,808,423	288	1	31	136.76	0	0	1	170,904	*81,710,562*	
Nov-06	83,973,333	382	-	30	137.04	0	0	0	187,995	*83,162,263*	
Dec-06	87,799,550	501	-	31	137.33	0	0	0	205,085	*87,028,829*	
Jan-07	92,807,711	647	-	31	137.55	0	0	0	216,606	*89,455,569*	
Feb-07	87,369,732	740	-	28	137.78	0	0	0	228,127	*85,297,508*	
Mar-07	89,810,436	547	-	31	138.01	0	0	0	239,648	*87,923,695*	
Apr-07	80,121,095	356	-	30	138.23	1	0	0	251,169	*78,677,613*	
May-07	80,608,589	136	22	31	138.46	0	1	0	262,690	*80,579,590*	
Jun-07	89,502,716	17	99	30	138.69	0	0	0	274,212	*88,702,075*	
Jul-07	89,014,824	3	106	31	138.92	0	0	0	285,733	*91,215,629*	
Aug-07	94,084,356	5	141	31	139.15	0	0	0	297,254	*95,216,462*	
Sep-07	82,681,855	37	48	30	139.38	0	0	0	308,775	*83,376,938*	
Oct-07	83,253,588	138	20	31	139.61	0	0	1	320,296	*81,942,201*	
Nov-07	85,256,947	463	-	30	139.84	0	0	0	331,817	*85,048,937*	
Dec-07	88,503,147	631	-	31	140.07	0	0	0	343,338	*89,733,511*	
Jan-08	91,586,649	624	-	31	139.97	0	0	0	359,620	*89,453,118*	
Feb-08	87,242,239	675	-	29	139.86	0	0	0	375,902	*86,310,032*	
Mar-08	88,370,234	610	-	31	139.76	0	0	0	392,184	*88,910,308*	
Apr-08	79,320,755	254	-	30	139.65	1	0	0	408,466	*76,758,671*	
May-08	77,025,833	194	3	31	139.55	0	1	0	424,748	*78,803,173*	
Jun-08	84,090,015	23	72	30	139.44	0	0	0	441,030	*85,011,402*	
Jul-08	91,739,839	1	111	31	139.34	0	0	0	457,312	*90,836,368*	
Aug-08	85,561,377	13	64	31	139.23	0	0	0	473,595	*85,585,556*	
Sep-08	81,335,600	59	27	30	139.13	0	0	0	489,877	*80,080,190*	
Oct-08	79,888,372	279	-	31	139.02	0	0	1	506,159	*80,471,947*	
Nov-08	81,455,826	452	-	30	138.92	0	0	0	522,441	*83,125,606*	
Dec-08	85,806,592	655	-	31	138.81	0	0	0	538,723	*88,161,203*	
Jan-09	90,223,487	830	-	31	138.39	0	0	0	578,878	*90,517,979*	
Feb-09	77,995,973	606	-	28	137.97	0	0	0	619,033	*80,680,018*	
Mar-09	80,993,879	534	-	31	137.54	0	0	0	659,189	*84,726,646*	
Apr-09	72,518,420	306	1	30	137.13	1	0	0	699,344	*74,464,657*	
May-09	72,158,813	159	7	31	136.71	0	1	0	739,499	*75,137,380*	
Jun-09	76,645,030	49	34	30	136.29	0	0	0	779,654	*77,332,521*	
Jul-09	77,751,228	6	44	31	135.87	0	0	0	819,810	*79,117,007*	
Aug-09	84,421,103	10	91	31	135.46	0	0	0	859,965	*83,999,091*	
Sep-09	74,688,913	55	21	30	135.05	0	0	0	900,120	*74,472,743*	
Oct-09	75,437,058	288	-	31	134.63	0	0	1	940,275	*75,403,857*	
Nov-09	75,196,070	361	-	30	134.22	0	0	0	980,431	*76,119,385*	
Dec-09	82,800,231	631	-	31	133.81	0	0	0	1,020,586	*81,922,115*	
Jan-10	85,740,318	720	-	31	134.14	0	0	0	1,020,471	*83,541,492*	
Feb-10	76,200,453	598	-	28	134.47	0	0	0	1,020,357	*76,032,303*	
Mar-10	78,025,071	423	-	31	134.81	0	0	0	1,020,242	*79,081,422*	
Apr-10	69,790,834	225	-	30	135.14	1	0	0	1,020,128	*69,848,034*	
May-10	76,066,070	108	46	31	135.47	0	1	0	1,020,013	*76,167,111*	
Jun-10	79,225,718	22	59	30	135.81	0	0	0	1,019,899	*77,805,860*	
Jul-10	89,977,040	2	165	31	136.14	0	0	0	1,019,784	*91,495,647*	
Aug-10	88,856,918	2	139	31	136.48	0	0	0	1,019,670	*88,753,278*	
Sep-10	74,349,622	78	32	30	136.81	0	0	0	1,019,555	*76,216,944*	
Oct-10	73,264,038	242	-	31	137.15	0	0	1	1,019,441	*75,507,017*	
Nov-10	76,397,905	405	-	30	137.49	0	0	0	1,019,326	*78,357,674*	
Dec-10	82,865,127	676	-	31	137.83	0	0	0	1,019,212	*84,843,211*	
Jan-11	86,054,286	775	-	31	138.03	0	0	0	1,059,909	*86,297,164*	
Feb-11	76,331,650	654	-	28	138.24	0	0	0	1,100,606	*78,463,273*	
Mar-11	80,293,454	573	-	31	138.44	0	0	0	1,141,304	*82,704,405*	
Apr-11	71,266,778	332	-	30	138.65	1	0	0	1,182,001	*72,441,615*	
May-11	72,652,306	134	13	31	138.86	0	1	0	1,222,699	*73,439,538*	
Jun-11	76,886,232	19	52	30	139.06	0	0	0	1,263,396	*77,215,696*	
Jul-11	93,432,708	-	199	31	139.27	0	0	0	1,304,093	*95,086,854*	
Aug-11	86,792,643	-	122	31	139.48	0	0	0	1,344,791	*86,366,829*	
Sep-11	75,561,451	48	40	30	139.69	0	0	0	1,385,488	*75,827,708*	
Oct-11	73,210,552	236	2	31	139.89	0	0	1	1,426,186	*74,515,994*	
Nov-11	74,362,595	342	-	30	140.10	0	0	0	1,466,883	*75,833,783*	
Dec-11	78,058,079	534	-	31	140.31	0	0	0	1,507,580	*80,700,333*	
Jan-12	83,475,292	611	-	31	140.50	0	0	0	1,532,097	*81,887,494*	
Feb-12	76,561,560	532	-	29	140.68	0	0	0	1,556,614	*76,740,007*	
Mar-12	76,020,278	349	0	31	140.87	0	0	0	1,581,131	*77,551,503*	
Apr-12	69,885,112	322	-	30	141.05	1	0	0	1,605,648	*70,813,750*	
May-12	77,152,267	81	37	31	141.24	0	1	0	1,630,165	*73,883,023*	
Jun-12	83,683,997	23	102	30	141.43	0	0	0	1,654,682	*81,564,539*	
Jul-12	97,430,291	-	190	31	141.61	0	0	0	1,679,199	*92,972,341*	
Aug-12	90,717,699	2	112	31	141.80	0	0	0	1,703,716	*84,188,671*	
Sep-12	77,862,575	85	36	30	141.99	0	0	0	1,728,232	*74,982,624*	
Oct-12	75,966,062	243	1	31	142.18	0	0	1	1,752,749	*73,596,538*	
Nov-12	77,579,681	434	-	30	142.37	0	0	0	1,777,266	*76,532,448*	
Dec-12	78,044,417	534	-	31	142.55	0	0	0	1,801,783	*79,994,510*	
Jan-13		719	-	31	142.73	0	0	0	1,812,561	*83,033,858*	
Feb-13		636	-	28	142.91	0	0	0	1,823,340	*75,989,505*	
Mar-13		523	0	31	143.09	0	0	0	1,834,118	*79,903,531*	
Apr-13		310	0	30	143.26	1	0	0	1,844,896	*70,304,820*	
May-13		148	16	31	143.44	0	1	0	1,855,674	*72,388,560*	
Jun-13		27	72	30	143.62	0	0	0	1,866,453	*78,131,375*	
Jul-13		2	138	31	143.80	0	0	0	1,877,231	*86,988,094*	
Aug-13		5	110	31	143.98	0	0	0	1,888,009	*83,972,642*	
Sep-13		55	33	30	144.16	0	0	0	1,898,787	*74,294,264*	
Oct-13		243	3	31	144.33	0	0	1	1,909,566	*74,014,751*	
Nov-13		400	-	30	144.51	0	0	0	1,920,344	*76,223,633*	
Dec-13		603	-	31	144.69	0	0	0	1,931,122	*81,443,297*	

Weather Normal

2003	964,286,210		2003	*970,363,655*
2004	989,608,990		2004	*974,909,760*
2005	1,025,654,030		2005	*1,029,456,186*
2006	1,022,795,092		2006	*1,019,102,992*
2007	1,043,014,997		2007	*1,037,169,727*
2008	1,013,423,330		2008	*1,013,507,574*
2009	940,830,205		2009	*953,893,400*
2010	950,759,113		2010	*957,649,995*
2011	944,902,732		2011	*958,893,191*
2012	964,379,231		2012	*944,707,448*
2013			2013	*936,688,331*
Total to 2011	9,859,653,929			

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.957
R Square	0.916
Adjusted R Square	0.910
Standard Error	1,892,531.205
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	8	4.36264E+15	5.453E+14	152.25572	3.53308E-56
Residual	111	3.97566E+14	3.582E+12		
Total	119	4.76021E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	(53,511,157.89)	9,854,871.11	(5.43)	0.00	(73,039,242.87)	(33,983,072.91)	(73,039,242.87)	(33,983,072.91)
Heating Degree Days	16,224.51	1,068.75	15.18	0.00	14,106.70	18,342.32	14,106.70	18,342.32
Cooling Degree Days	112,284.33	5,737.81	19.57	0.00	100,914.47	123,654.19	100,914.47	123,654.19
Number of Days in Month	1,905,123.78	237,972.89	8.01	0.00	1,433,564.61	2,376,682.95	1,433,564.61	2,376,682.95
Real Ontario GDP (chained $1997 with Base 100 in 1997)	543,951.74	51,498.62	10.56	0.00	441,903.78	645,999.69	441,903.78	645,999.69
April	(4,302,273.06)	673,034.63	(6.39)	0.00	(5,635,936.11)	(2,968,610.01)	(5,635,936.11)	(2,968,610.01)
May	(3,300,241.50)	729,154.08	(4.53)	0.00	(4,745,108.99)	(1,855,374.02)	(4,745,108.99)	(1,855,374.02)
October	(1,915,088.82)	720,616.96	(2.66)	0.01	(3,343,039.43)	(487,138.21)	(3,343,039.43)	(487,138.21)
Negative Impact Variable	(6.52)	0.42	(15.58)	0.00	(7.35)	(5.69)	(7.35)	(5.69)

RESIDUAL OUTPUT

Observation	*Predicted Total Purchases*	*Residuals*
1	87,115,653.72	272632.2838
2	79,605,589.59	-355751.2879
3	83,487,421.19	-1946520.691
4	74,244,495.89	-43158.49449
5	73,804,393.21	-1200662.814
6	79,036,761.50	-1757805.205
7	87,664,080.01	3310726.589
8	88,862,232.98	-7044917.682
9	76,217,698.99	1946732.614
10	77,180,125.20	892464.9991
11	79,257,661.39	-16201.99341
12	83,887,541.81	-134984.3087
13	88,696,312.94	2141178.058
14	81,501,752.69	1592124.512
15	83,112,371.14	1920271.359
16	74,520,680.72	1794163.883
17	75,736,911.49	1251118.211
18	77,997,694.27	2203768.335
19	85,541,657.71	-1176902.715
20	82,826,374.17	931575.5339
21	79,279,249.27	1843472.028
22	78,141,735.29	771328.0149
23	80,607,945.76	815694.7429
24	86,947,074.18	611438.42
25	89,158,815.99	2555596.328
26	81,109,429.30	-32614.12892
27	86,856,670.19	320128.516
28	75,911,489.06	-647815.5927
29	77,162,840.12	1307738.214
30	92,126,282.97	722685.7301
31	98,807,698.01	-3962298.877
32	93,581,484.26	-438208.8125
33	82,251,943.16	-1409643.174
34	80,612,190.68	-1343770.193
35	82,659,017.02	-68288.58319
36	89,218,325.67	-805665.7856
37	87,415,489.91	1367180.389
38	82,590,860.67	61865.68311
39	86,922,607.68	364655.5118
40	77,131,853.42	-1001841.997
41	80,460,774.72	987744.4298
42	85,336,067.56	1330154.502
43	97,486,365.94	-1280901.44
44	90,218,252.52	1747286.002
45	79,639,066.43	-1563695.789
46	81,710,561.75	97860.92653
47	83,162,262.56	811070.8007
48	87,028,828.55	770721.2969
49	89,455,569.11	3352141.896
50	85,297,508.33	2072224.07
51	87,923,694.68	1886741.227
52	78,677,613.24	1443482.257
53	80,579,589.77	28999.09132
54	88,702,074.70	800641.7014
55	91,215,629.34	-2200805.682
56	95,216,462.19	-1132105.732
57	83,376,937.56	-695082.9578
58	81,942,200.59	1311387.036
59	85,048,936.93	208010.3371
60	89,733,510.60	-1230363.57
61	89,453,117.57	2133531.07
62	86,310,031.57	932207.0792
63	88,910,308.08	-540074.2977
64	76,758,671.30	2562083.657
65	78,803,173.16	-1777340.461
66	85,011,402.42	-921387.4306
67	90,836,367.55	903471.4518
68	85,585,556.14	-24179.21924
69	80,080,189.97	1255410.294
70	80,471,946.96	-583574.6318
71	83,125,606.35	-1669780.434
72	88,161,202.68	-2354611.114
73	90,517,979.39	-294492.2249
74	80,680,018.17	-2684045.526
75	84,726,646.11	-3732767.455
76	74,464,656.64	-1946236.977
77	75,137,380.43	-2978567.317
78	77,332,521.39	-687491.4618
79	79,117,006.89	-1365778.553
80	83,999,090.79	422012.0928
81	74,472,743.10	216170.3717
82	75,403,857.13	33201.04839
83	76,119,385.35	-923315.8044
84	81,922,115.01	878116.442
85	83,541,491.86	2198825.818
86	76,032,303.18	168149.3351
87	79,081,422.40	-1056351.871
88	69,848,034.21	-57200.52646
89	76,167,111.10	-101041.5899
90	77,805,859.75	1419857.892
91	91,495,647.12	-1518606.944
92	88,753,278.47	103639.8197
93	76,216,944.42	-1867322.115
94	75,507,017.38	-2242979.123
95	78,357,674.32	-1959769.15
96	84,843,211.26	-1978084.364
97	86,297,163.52	-242877.3912
98	78,463,273.28	-2131623.438
99	82,704,404.98	-2410950.677
100	72,441,615.38	-1174837.408
101	73,439,537.70	-787231.9116
102	77,215,695.52	-329463.6216
103	95,086,853.58	-1654145.865
104	86,366,829.47	425813.1613
105	75,827,707.80	-266257.1393
106	74,515,993.81	-1305442.225
107	75,833,783.17	-1471188.564
108	80,700,332.80	-2642253.813
109	81,887,493.90	1587798.342
110	76,740,007.41	-178447.809
111	77,551,502.67	-1531224.792
112	70,813,750.46	-928638.8019
113	73,883,023.13	3269244.148
114	81,564,538.84	2119458.054
115	92,972,340.78	4457950.398
116	84,188,670.69	6529028.059
117	74,982,623.58	2879951.413
118	73,596,538.15	2369524.148
119	76,532,448.02	1047232.918
120	79,994,509.99	-1950092.992

Summary of Degree Day Informatio **Station Name** **TORONTO LESTER B. PEARSON INT'L A**

Summary of All Heating Degree Days

Month	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Year Avg	20 Year Trend
January	635.10	941.40	653.20	765.20	756.60	624.80	749.80	738.90	684.90	572.20	814.50	849.10	770.00	551.80	647.10	623.50	830.20	720.00	775.30	610.80	719.23	690.48
February	686.80	737.50	707.00	689.80	593.00	512.20	548.10	612.70	587.60	540.20	699.00	631.70	616.40	604.30	740.10	674.70	606.40	598.30	654.20	532.00	635.71	601.61
March	530.10	581.50	498.10	645.60	600.00	492.30	550.60	418.60	566.60	545.60	581.10	487.30	608.60	516.60	546.70	610.20	533.80	422.80	572.80	349.40	522.93	493.03
April	280.30	320.20	417.60	408.20	366.80	282.00	296.70	339.20	293.80	329.50	372.50	331.50	306.80	293.30	356.40	253.90	305.80	225.10	332.30	321.70	309.93	291.46
May	182.00	199.70	149.20	205.90	260.80	59.10	97.10	139.60	111.50	227.50	177.90	158.90	189.40	136.90	136.40	193.50	158.80	107.90	134.10	81.30	147.51	126.29
June	46.50	35.60	20.00	20.90	20.60	54.70	25.00	34.50	29.80	36.20	43.40	44.20	8.90	19.50	16.50	22.70	49.30	21.70	19.00	23.20	26.84	23.55
July	0.60	2.40	10.30	10.30	12.40	1.00	-	6.60	9.30	-	0.20	3.60	-	-	3.20	1.00	6.20	1.80	-	-	1.60	0.38
August	9.70	24.50	4.60	2.50	17.00	3.40	8.40	11.50	-	0.20	2.00	12.80	0.20	4.20	5.20	12.70	9.80	2.10	-	2.00	5.10	2.04
September	77.20	76.20	133.70	71.60	87.10	39.70	49.30	99.50	73.60	21.80	54.90	30.00	22.60	80.90	36.90	59.00	55.20	78.10	48.20	85.00	55.08	48.47
October	200.80	249.30	219.40	273.10	266.90	223.40	267.60	212.70	232.50	292.20	276.00	226.30	220.20	288.30	137.70	278.60	287.80	241.60	235.50	242.50	243.45	248.25
November	312.50	379.00	511.40	512.10	466.50	392.60	367.50	432.00	325.80	445.00	398.50	379.10	388.40	382.20	462.50	451.60	361.20	405.30	342.10	434.00	400.49	396.35
December	503.50	562.50	717.50	571.60	586.20	535.10	579.30	780.30	505.00	619.40	561.50	643.40	665.30	500.50	630.70	654.60	631.30	676.20	534.00	533.50	603.10	608.14
Total	3,465.10	4,109.80	4,042.00	4,176.80	4,033.90	3,220.30	3,539.40	3,826.10	3,420.40	3,629.80	3,981.50	3,797.90	3,796.80	3,378.50	3,719.40	3,836.00	3,835.80	3,500.90	3,647.50			

Summary of All Cooling Degree Days

Month	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Year Avg	20 Year Trend
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.20	0.02	0.04
April	-	0.50	-	-	-	-	-	-	1.40	8.30	2.40	-	-	-	-	-	1.20	-	-	-	0.36	0.67
May	4.30	8.20	3.50	8.60	-	28.60	19.40	23.70	12.20	7.80	-	8.60	0.80	26.00	22.40	2.50	6.90	45.70	13.00	36.70	16.26	23.36
June	17.90	67.70	77.90	38.30	73.20	82.40	96.00	41.10	79.70	70.00	52.90	31.60	146.30	73.60	99.20	71.50	34.20	58.70	52.20	101.60	72.18	78.77
July	107.80	111.20	130.90	59.60	103.00	101.30	196.50	71.80	100.90	192.40	118.30	86.40	188.70	167.30	106.10	111.00	43.70	164.90	198.50	190.10	137.50	157.08
August	103.50	46.40	122.90	87.10	46.80	117.70	79.10	92.50	160.00	142.70	128.00	59.60	140.70	101.60	141.00	64.00	91.00	138.80	122.20	112.10	109.90	122.43
September	15.70	13.70	12.70	27.10	11.70	45.00	48.90	35.20	35.70	87.60	24.00	41.20	52.10	12.90	47.50	26.70	20.90	31.50	39.70	35.60	33.21	41.12
October	2.50	-	3.20	-	2.80	-	-	1.20	2.00	10.00	-	1.50	7.60	1.10	19.80	-	-	-	2.40	1.10	3.35	3.88
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00
Total	251.70	247.70	351.10	220.70	237.50	375.00	439.90	265.50	391.90	518.80	325.60	228.90	536.20	382.50	436.00	275.70	197.90	439.60	428.00			

	Coefficients
Intercept	(53,960,036.90)
Heating De	15,963.03
Cooling De	110,374.36
Number of	1,909,211.10
Real Ontari	549,023.30
April	(4,364,938.90)
May	(3,385,062.27)
October	(2,029,353.76)
CDM Activi	(5.71)

Jan-13	690	0	31	142.73	0	0	0	1,935,349
Feb-13	602	0	28	142.91	0	0	0	1,923,802
Mar-13	493	0.04	31	143.09	0	0	0	1,912,255
Apr-13	291	0.666316	30	143.26	1	0	0	1,900,708
May-13	126	23.36263	31	143.44	0	1	0	1,889,162
Jun-13	24	78.76684	30	143.62	0	0	0	1,877,615
Jul-13	0	157.0842	31	143.80	0	0	0	1,866,068
Aug-13	2	122.4326	31	143.98	0	0	0	1,854,522
Sep-13	48	41.12053	30	144.16	0	0	0	1,842,975
Oct-13	248	3.879474	31	144.33	0	0	1	1,831,428
Nov-13	396	0	30	144.51	0	0	0	1,819,882
Dec-13	608	0	31	144.69	0	0	0	1,808,335

814.50	-
699.00	-
581.10	-
372.50	2.40
177.90	-
43.40	52.90
0.20	118.30
2.00	128.00
54.90	24.00
276.00	-
398.50	-
561.50	-
849.10	-
631.70	-
487.30	-
331.50	-
158.90	8.60
44.20	31.60
3.60	86.40
12.80	59.60
30.00	41.20
226.30	1.50
379.10	-
643.40	-
770.00	-
616.40	-
608.60	-
306.80	-
189.40	0.80
8.90	146.30
-	188.70
0.20	140.70
22.60	52.10
220.20	7.60
388.40	-
665.30	-
551.80	-
604.30	-
516.60	-
293.30	-
136.90	26.00
19.50	73.60
-	167.30
4.20	101.60
80.90	12.90
288.30	1.10
382.20	-
500.50	-
647.10	-
740.10	-
546.70	-
356.40	-
136.40	22.40
16.50	99.20
3.20	106.10
5.20	141.00
36.90	47.50
137.70	19.80
462.50	-
630.70	-
623.50	-
674.70	-
610.20	-
253.90	-
193.50	2.50
22.70	71.50
1.00	111.00
12.70	64.00
59.00	26.70
278.60	-
451.60	-
654.60	-
830.20	-
606.40	-
533.80	-
305.80	1.20
158.80	6.90
49.30	34.20
6.20	43.70
9.80	91.00
55.20	20.90
287.80	-
361.20	-
631.30	-
720.00	-
598.30	-
422.80	-
225.10	-
107.90	45.70
21.70	58.70
1.80	164.90
2.10	138.80
78.10	31.50
241.60	-
405.30	-
676.20	-
775.30	-
654.20	-
572.80	-
332.30	-
134.10	13.00
19.00	52.20
-	198.50
-	122.20
48.20	39.70
235.50	2.40
342.10	-
534.00	-
610.80	-
532.00	-
349.40	0.20
321.70	-
81.30	36.70
23.20	101.60
-	190.10
2.00	112.10
85.00	35.60
242.50	1.10
434.00	-
533.50	-

2006-2(

#	Program Year	Results Status	2006	2007	2008
1	2006 Programs	Final	2,666,105	2,666,105	2,666,105
2	2007 Programs	Final	0	1,387,120	1,375,497
3	2008 Programs	Final	0	0	2,696,911
4	2009 Programs	Final	0	0	0
5	2010 Programs	Final	0	0	0
Total			**2,666,105**	**4,053,225**	**6,738,513**

	2006	2007	2008
Total OPA Annual C	2,666,105	4,053,225	6,738,513
Total New Results	2,666,105	1,387,120	2,696,911
Half Year New Resu	1,333,053	693,560	1,348,455
Total Annual Result	1,333,053	3,359,665	5,390,057

	Total OPA Annual CDM Results (Net kWh)	Total New Results (Net kWh)
	(A)	(B)
2006	2,666,105	2,666,105
2007	4,053,225	1,387,120
2008	6,738,513	2,696,911
2009	13,068,447	6,943,327
2010	14,323,507	4,170,820
2011	17,662,675	4,515,479
2012	22,587,351	5,168,137
2013	22,462,102	5,168,137

)10 Program Results

2009	2010	2011	2012	2013	2014
2,666,105	463,043	463,043	423,559	423,559	397,999
1,375,497	1,375,497	1,374,565	1,319,406	1,319,406	1,319,406
2,083,518	2,083,518	2,083,518	1,953,835	1,952,594	1,818,844
6,943,327	6,230,629	6,230,629	6,227,931	6,110,294	5,806,438
0	4,170,820	2,995,440	2,991,631	2,989,350	2,866,698
13,068,447	**14,323,507**	**13,147,196**	**12,916,363**	**12,795,202**	**12,209,385**

		2013 Proposed Cost of Service Method			
Program Year	**Results Status**	2011	2012	2013	2014
2011 Programs	Final	4,515,479	4,502,851	4,498,762	4,394,084
2012 Programs	Estimated		5,168,137	5,168,137	5,168,137
2013 Programs	Estimated			5,168,137	5,168,137
2014 Programs	Estimated				5,168,137
		4,515,479	9,670,988	14,835,037	19,898,496

2009	2010	2011	2012	2013
13,068,447	14,323,507	17,662,675	22,587,351	22,462,102
6,943,327	4,170,820	4,515,479	5,168,137	5,168,137
3,471,663	2,085,410	2,257,740	2,584,069	2,584,069
9,596,783.70	12,238,097	15,404,936	20,003,282	22,462,102

Half Year New Results (Net kWh)	Negative Impact Variable: Total Annual Results (Net kWh, half-year adjusted)
(C)=1/2*(B)	(D)=(A)- (C)
1,333,053	1,333,053
693,560	3,359,665
1,348,455	5,390,057
3,471,663	9,596,784
2,085,410	12,238,097
2,257,740	15,404,936
2,584,069	20,003,282
2,584,069	22,462,102

Total
17,911,176
15,504,412
10,336,275
5,168,137
48,920,000

________ Load Forecast for 2013 Rate Application

	Total OPA Annual NET CDM Results	Total OPA Annual CDM Results (Net)	# Difference	Net-Gross	Total Annual NET CDM Results	Increase over previous year			
2005						-	-	Check	
2006	2,666,105	1,333,053	1,333,053	200.0%	1,333,053	1,333,053	17,090	1,333,053	-
2007	4,053,225	3,359,665	693,560	120.6%	3,359,665	898,645	11,521	3,359,665	-
2008	6,738,513	5,390,057	1,348,455	125.0%	5,390,057	1,270,001	16,282	5,390,057	-
2009	13,068,447	9,596,784	3,471,663	136.2%	9,596,784	3,132,110	40,155	9,596,784	-
2010	22,580,989	12,238,097	10,342,892	184.5%	12,238,097	- 8,934	- 115	12,238,097	-
2011	21,419,144	15,404,936	6,014,208	139.0%	15,404,936	3,174,398	40,697	15,404,936	-
2012	20,892,615	20,003,282	889,333	104.4%	20,003,282	1,912,318	24,517	20,003,282	-
2013	20,654,711	22,462,102	(1,807,391)	92.0%	22,462,102	840,705	10,778	22,462,102	-
Total	112,073,749	89,787,975	22,285,773	124.8%	89,787,975				

	CDM Activity Variable		
Jan-06	17,090		
Feb-06	34,181		
Mar-06	51,271		
Apr-06	68,362		
May-06	85,452		
Jun-06	102,543		
Jul-06	119,633		
Aug-06	136,723		
Sep-06	153,814		
Oct-06	170,904		
Nov-06	187,995	Check	
Dec-06	205,085	1,333,053	2,461,020
Jan-07	216,606		
Feb-07	228,127		
Mar-07	239,648		
Apr-07	251,169		
May-07	262,690		
Jun-07	274,212		
Jul-07	285,733		
Aug-07	297,254		
Sep-07	308,775		
Oct-07	320,296		
Nov-07	331,817	Check	
Dec-07	343,338	3,359,665	4,120,057
Jan-08	359,620		
Feb-08	375,902		
Mar-08	392,184		
Apr-08	408,466		
May-08	424,748		
Jun-08	441,030		
Jul-08	457,312		
Aug-08	473,595		
Sep-08	489,877		
Oct-08	506,159		
Nov-08	522,441		
Dec-08	538,723	5,390,057	6,464,673
Jan-09	578,878		
Feb-09	619,033		
Mar-09	659,189		
Apr-09	699,344		
May-09	739,499		
Jun-09	779,654		
Jul-09	819,810		
Aug-09	859,965		
Sep-09	900,120		
Oct-09	940,275		
Nov-09	980,431		
Dec-09	1,020,586	9,596,784	12,247,031
Jan-10	1,020,471		
Feb-10	1,020,357		
Mar-10	1,020,242		
Apr-10	1,020,128		
May-10	1,020,013		
Jun-10	1,019,899		
Jul-10	1,019,784		
Aug-10	1,019,670		
Sep-10	1,019,555		
Oct-10	1,019,441		
Nov-10	1,019,326		
Dec-10	1,019,212	12,238,097	12,230,538
Jan-11	1,059,909		
Feb-11	1,100,606		
Mar-11	1,141,304		
Apr-11	1,182,001		
May-11	1,222,699		
Jun-11	1,263,396		
Jul-11	1,304,093		
Aug-11	1,344,791		
Sep-11	1,385,488		
Oct-11	1,426,186		
Nov-11	1,466,883		
Dec-11	1,507,580	15,404,936	18,090,965
Jan-12	1,532,097		
Feb-12	1,556,614		
Mar-12	1,581,131		
Apr-12	1,605,648		
May-12	1,630,165		
Jun-12	1,654,682		
Jul-12	1,679,199		
Aug-12	1,703,716		
Sep-12	1,728,232		
Oct-12	1,752,749		
Nov-12	1,777,266		
Dec-12	1,801,783	20,003,282	21,621,397
Jan-13	1,812,561		
Feb-13	1,823,340		
Mar-13	1,834,118		
Apr-13	1,844,896		
May-13	1,855,674		
Jun-13	1,866,453		
Jul-13	1,877,231		
Aug-13	1,888,009		
Sep-13	1,898,787		
Oct-13	1,909,566		
Nov-13	1,920,344		
Dec-13	1,931,122	22,462,102	23,173,467

Jan	1
Feb	2
Mar	3
Apr	4
May	5
Jun	6
Jul	7
Aug	8
Sep	9
Oct	10
Nov	11
Dec	12
Total	78

4 Year 2011 to 2014 target
48,920,000

2013 Proposed Cost of Service Method

2011	2012	2013	2014	Total	
9.2%	9.2%	9.2%	9.0%	36.6%	
	10.6%	10.6%	10.6%	31.7%	
		10.6%	10.6%	21.1%	
			10.6%	10.6%	
9.2%	19.8%	30.3%	40.7%	100.0%	
4,515,479	4,502,851	4,498,762	4,394,084	17,911,176	manual input
	5,168,137	5,168,137	5,168,137	15,504,412	
		5,168,137	5,168,137	10,336,275	
			5,168,137	5,168,137	
4,515,479	9,670,988	14,835,037	19,898,496	48,920,000	

Net to Gross 124.8%

2011	2012	2013	2014
5,636,241.17	12,071,370.26	18,517,158.38	24,837,390.85

48.92

4.515479 4.502851 4.498762 4.394084

			Gross	NTG%	NTG Impact	2011	2012

CDM Split By Class from 2011 OPA Final Results		
	2011 Net Energy Savings	
Residential	1,197,730.00	27%
GS<50 kW	1,609,340.00	36%
GS50 to 4999 kW	623,720.00	38%
pre-2011 programs*	1,084,690.00	
Totals	**4,515,480.00**	100%

*BPI has determined these programs to be industrial programs and included them in the GS>50 kW class.

Allocation of Expected Savings			
		9,670,988	**14,835,037**
Year	Share of Net Savings	2012	2013
Residential	**27%**	2,565,227	3,934,990
GeneralService <50KW	**36%**	3,446,789	5,287,282
General Service >50KW	**38%**	3,658,972	5,612,764
		9,670,988	14,835,037
Expected kW Savings			
	KW/kWh ratio	2012	2013
GS>50-kW	0.255%	9,314.74	14,288.56

Allocation of 2013 Expected Savings		
	Share of Savings	2013
Expected Kwh Savings		**2,584,069**
Residential	**27%**	685,424
GeneralService <50KW	**36%**	920,975
General Service >50KW	**38%**	977,670
Total	100%	2,584,069
Expected kW Savings		
	KW/kWh ratio	2012
General Service >50KW	*0.255%*	*2,489*

19,898,496
2014
5,278,071
7,091,925
7,528,500
19,898,496
2014
19,165.50

Purchases	Modeled Purchases	Difference	% Difference	Loss Factor	Total Billed	Residential	GS<50

Residential GS<50

ATTACHMENT J

REFERENCE: 3.0 Staff-13

saveONenergy

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2012 Results Report. We have seen a 39% increase in energy savings for our new province-wide 2011-2014 suite of saveONenergy initiatives. Overall progress to targets is moving up with 29% of demand and 65% of energy savings achieved. Many LDCs, both large and small, continue to stay on track to meet or exceed their OEB targets. Conservation programs continue to be a valuable and cost effective resource for customers across the province, over the past two years the program cost to consumers remains within 3 cents per kWh.

Further to programmatic savings, capability building efforts launched in 2011 are yielding healthy enabled savings through Embedded Energy Managers and Audit initiative projects. The strong momentum continues in 2013.

We remain committed to ensuring LDCs are successful in meeting their objectives and our collective efforts to date have improved the current program suite by offering more local program opportunities, implementing a new expedited change management process, and enhancing incentives to make it easier for customers to participate in programs. We invite you to continue to provide your feedback to us and to celebrate our successes as we move forward.

The format of this report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. All results are now considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year.

Sincerely,

Andrew Pride

Table of Contents

OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

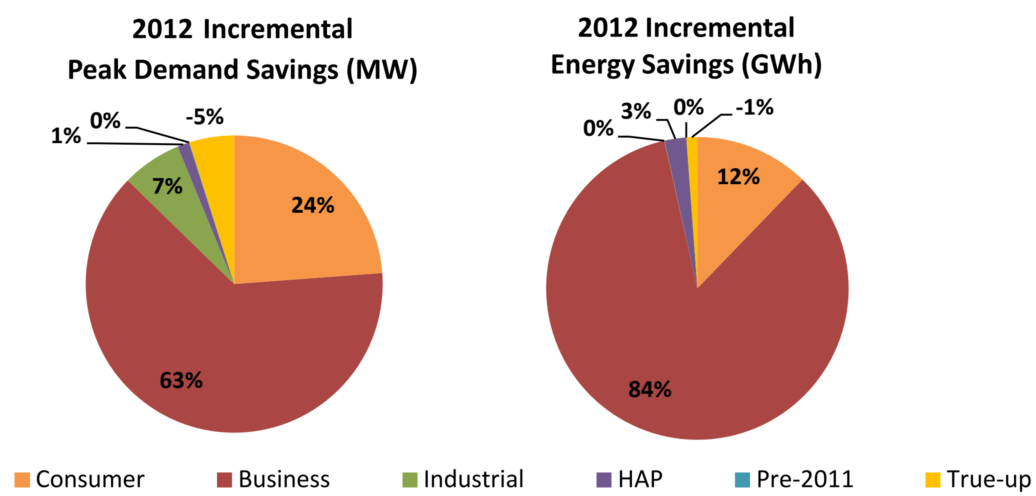
LDC: Brantford Power Inc.

FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	1.2	1.9	**16.6%**	**18.8%**
Net Energy Savings (GWh)	5.4	33.6	**68.8%**	**68.8%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

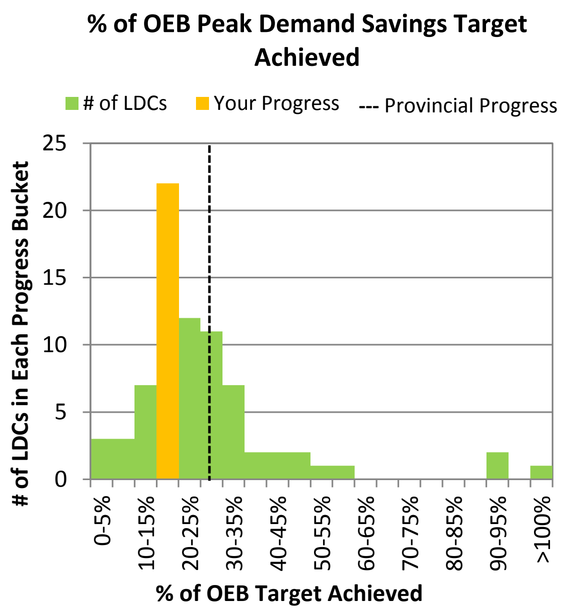
Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector



Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)



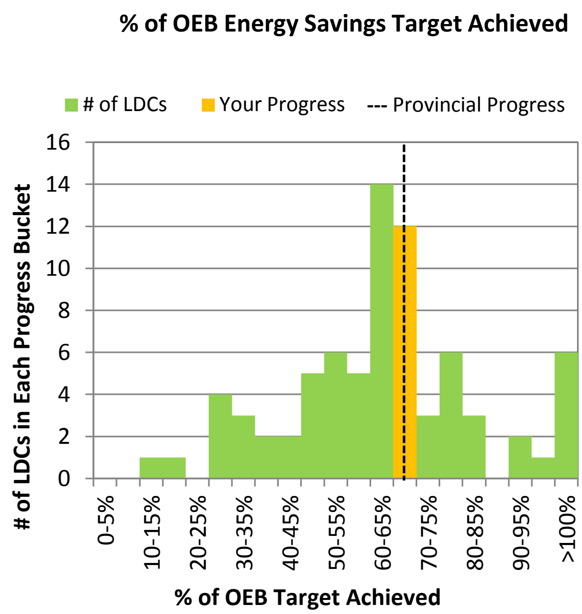


Table 1: **Brantford Power Inc.** Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	607	405			35	24			250,242	159,035			57	1,477,468
Appliance Exchange	Appliances	81	4			9	1			12,869	968			6	50,932
HVAC Incentives	Equipment	1,092	864			310	192			571,421	327,050			502	3,266,833
Conservation Instant Coupon Booklet	Items	3,702	224			9	2			149,983	10,144			11	630,366
Bi-Annual Retailer Event	Items	6,314	7,697			12	11			213,214	194,308			23	1,435,779
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	192	198			108	91			278	686			0	964
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**483**	**320**			**1,198,008**	**692,192**			**599**	**6,862,343**
Business Program															
Retrofit	Projects	20	46			179	712			1,194,344	4,496,823			869	18,146,855
Direct Install Lighting	Projects	102	64			159	69			412,361	269,848			192	2,350,189
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	0			0	0			0	0			0	0
Energy Audit	Audits	0	0			0	0			0	0			0	0
Small Commercial Demand Response	Devices	7	5			4	3			16	18			0	35
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	2	2			68	68			2,636	984			0	3,620
Business Program Total						**410**	**851**			**1,609,356**	**4,767,673**			**1,061**	**20,500,699**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	12				90				613,727				90	2,454,907
Demand Response 3	Facilities	2	1			170	87			9,993	2,104			0	12,097
Industrial Program Total						**261**	**87**			**623,720**	**2,104**			**90**	**2,467,004**
Home Assistance Program															
Home Assistance Program	Homes	0	105			0	17			0	130,921			17	392,764
Home Assistance Program Total						**0**	**17**			**0**	**130,921**			**17**	**392,764**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	29	0			141	0			842,905	0			141	3,371,618
High Performance New Construction	Projects	1	0			47	1			241,785	794			48	969,524
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**188**	**1**			**1,084,690**	**794**			**189**	**4,341,143**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-66**				**-230,189**			**-66**	**-920,756**
Energy Efficiency Total						**992**	**1,027**			**4,502,851**	**5,589,893**			**1,956**	**34,547,237**
Demand Response Total (Scenario 1)						**350**	**249**			**12,923**	**3,792**			**0**	**16,715**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**1,342**	**1,211**			**4,515,774**	**5,363,496**			**1,891**	**33,643,196**
													Full OEB Target:	**11,380**	**48,920,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**16.6%**	**68.8%**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to Brantford Power Inc. Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-236				-66				-120,601				-66	-482,404
Conservation Instant Coupon Booklet	Items	60				0				2,000				0	8,000
Bi-Annual Retailer Event	Items	594				1				15,841				1	63,364
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-65**				**-102,760**				**-65**	**-411,040**
Business Program															
Retrofit	Projects	1				0				1,040				0	4,159
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**0**				**1,040**				**0**	**4,159**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				-1				-128,469				-1	-513,875
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**-1**				**-128,469**				**-1**	**-513,875**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-66**				**-230,189**				**-66**	**-920,756**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3: Brantford Power Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		0.90				0.75				0.96				0.75		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.26				1.00				0.98				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	1.3	1.0	1.0	1.0
2012 - Verified		1.2	0.9	0.9
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				**1.9**
Brantford Power Inc. 2014 Annual CDM Capacity Target				**11.4**
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				**16.6%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	4.5	4.5	4.5	4.4	17.9
2012 - Verified		5.4	5.3	5.3	15.7
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**33.6**
Brantford Power Inc. 2011-2014 Annual CDM Energy Target					**48.9**
Verified Portion of Cumulative Energy Target Achieved (%):					**68.8%**

*2011 energy adjustments included in cumulative energy savings.

Table 6: Province-Wide Initiatives and Program Level Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Items	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Items	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	98,388			10,947	49,038			24,870	359,408			0	384,279
Residential Demand Response (IHD)	Devices	0	49,689			0				0					
Residential New Construction	Homes	7	19			0	2			743	17,152			2	54,430
Consumer Program Total						**49,681**	**72,377**			**133,520,941**	**75,796,859**			**61,696**	**760,348,879**
Business Program															
Retrofit	Projects	2,516	5,605			24,467	61,147			136,002,258	314,922,468			84,018	1,480,647,459
Direct Install Lighting	Projects	20,297	18,494			23,724	15,284			61,076,701	57,345,798			31,181	391,072,869
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	69			123	764			411,717	1,814,721			888	7,091,031
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response	Devices	132	294			84	187			157	1,068			0	1,224
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3*	Facilities	145	151			16,218	19,389			633,421	281,823			0	915,244
Business Program Total						**64,617**	**98,221**			**198,124,253**	**381,415,230**			**117,535**	**1,900,875,881**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	39			0	1,086			0	7,372,108			1,086	22,116,324
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	74,056			3,080,737	1,784,712			0	4,865,449
Industrial Program Total						**57,098**	**75,141**			**31,947,577**	**9,156,820**			**5,699**	**142,444,054**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033			2	566			39,283	5,442,232			569	16,483,831
Home Assistance Program Total						**2**	**566**			**39,283**	**5,442,232**			**569**	**16,483,831**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	69			5,098	3,251			26,185,591	11,901,944			8,349	140,448,197
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**			**243,251,550**	**11,901,944**			**48,195**	**1,008,712,030**
Other															
Program Enabled Savings	Projects	0	16			0	2,304			0	1,188,362			2,304	3,565,086
Time-of-Use Savings	Homes														
Other Total							**2,304**				**1,188,362**			**2,304**	**3,565,086**
Adjustments to Previous Year's Verified Results							**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total						**136,610**	**109,191**			**603,144,419**	**482,474,435**			**235,998**	**3,826,263,564**
Demand Response Total (Scenario 1)						**79,733**	**142,670**			**3,739,185**	**2,427,011**			**0**	**6,166,196**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**			**606,883,604**	**503,590,526**			**237,154**	**3,906,348,358**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**17.8%**	**65.1%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 7: Adjustments to **Province-Wide** Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-18,866				-5,278				-9,721,817				-5,278	-38,887,267
Conservation Instant Coupon Booklet	Items	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Items	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	19				1				13,767				1	55,069
Consumer Program Total						**-5,153**				**-7,249,004**				**-5,153**	**-28,996,015**
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	12				828				3,520,620				828	14,082,482
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**5,014**				**23,328,565**				**4,764**	**92,471,668**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12				138				545,536				138	2,182,145
High Performance New Construction	Projects	34				1,407				2,065,200				1,407	8,260,800
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**1,545**				**2,610,736**				**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**1,406**				**18,690,297**				**1,156**	**73,918,598**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.65				0.49				7.17				0.49		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		0.98				0.49				0.99				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.16				0.90				1.16				0.90		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.32				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		1.06				1.00				2.26				1.00		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		253.3	109.8	108.2
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				237.2
2014 Annual CDM Capacity Target				1,330
Verified Peak Demand Savings Target Achieved - 2011 (%):				17.8%

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		503.6	498.4	492.6	1,513
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					3,906
2011-2014 Cumulative CDM Energy Target:					6,000
Verified Portion of Energy Target Achieved - 2011 (%):					65.1%

*2011 energy adjustments included in cumulative energy savings.

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings =** Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings =** Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2012 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; No completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)

Building Type	Sector
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

ATTACHMENT K

REFERENCE: 4.0 Energy Probe-24

Canada Revenue Agency / Agence du revenu du Canada

Business Consent

Complete this form to consent to the release of confidential information about your program account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre (see Instructions).** Make sure you complete this form correctly, since we cannot change the information that you provide. You can also give **or** cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount**.

Note: Read all the instructions before completing this form.

Part 1 – Business information

Complete this part to identify your business (all fields have to be completed)

Business name: BRANTFORD POWER INC. BN: 865858773

Part 2 – Authorize a representative – Complete either (a) or (b)

(a) Authorize access by telephone, fax and by mail

If you are giving consent for an individual, enter that person's full name. If you are giving consent to a firm, enter the name and BN of the firm. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the firm's name and BN. If you do not identify an individual of the firm, then you are giving us consent to deal with anyone from that firm.

Note: If you are authorizing a representative (individual or firm) who is not registered with the "Represent a Client" service, the phone number is required.

Name of individual:

Name of firm:

Telephone number: Extension: BN:

or

(b) Authorize online access (includes access by telephone, fax and by mail)

You can authorize your representative to deal with us through our online service for representatives. The BN must be registered with the "Represent a Client" service to be an online representative. **Our online service does not have a year-specific option, so your representative will have access to all years.**

You **must** enter **one** of the following options:

- the RepID **and** the name of the **individual**; **or**
- the GroupID **and** the name of the **group**; **or**
- the BN **and** the name of the **firm**.

RepID: **and** Name of individual:
or
GroupID: G **and** Name of group:
or
BN: 133245290 **and** Name of firm: Deloitte LLP

Telephone number: (519) 650-7600 Extension:

Part 3 – Select the program accounts, years and authorization level

(a) Program Accounts – Select the program accounts the above individual, group or firm is authorized to access. Tick only **one** box, (**i**) **or** (**ii**).

(i) [X] This authorization applies to all program accounts and all years.

Expiry date:
and

Authorization level (tick level 1 or 2)

[ ] Level 1 lets CRA disclose information only on your program account(s);

or

[X] Level 2 lets CRA disclose information **and** accept changes to your program account(s).

or

(ii) [ ] This authorization applies only to program accounts and periods listed in Part 3(b). If you select this option, you must complete 3(b).

Business Consent

Part 3 – Select the program accounts, years and authorization level (continued)

(b) Details of program accounts and fiscal periods – Complete this area **only** if you ticked box (**ii**) in Part 3(a) on page 1.

If you ticked box (**ii**) in part 3(a), you have to provide at least one program identifier (see Instructions on page 1). You can then tick the box "All program accounts" for that program identifier **or** enter a reference number. Provide the authorization level (tick **either** the "**Authorization level 1** box" to allow the CRA to disclose information **or** "**Authorization level 2** box" to disclose information **and** accept changes to your program account).

You can also tick the box "All years" to allow unlimited tax year access **or** enter a specific fiscal period (specific period authorization **is not available** for online access). You can also enter an expiry date to automatically cancel authorization. If more authorizations or more than four program identifiers are needed, complete another Form RC59.

Program identifier	All program accounts		Reference number	Authorization level 1	Authorization level 2	All years		Specific fiscal period (not available for online access) Year-end	Expiry date
		or					or		
		or					or		
		or					or		
		or					or		

Part 4 – Cancel one or more authorizations

Complete this part **only** to **cancel** authorization(s)

A. ☐ Cancel all authorizations on **all** accounts.

B. ☐ Cancel all authorizations, only for the individual, group, or firm identified below.

C. ☐ Cancel all authorizations for a specific program account: Program identifier: Reference number:

D. ☐ Cancel authorization for the individual, group, or firm identified below for the following program account: Program identifier: Reference number:

RepID: **and** Name of individual:
or
GroupID: G **and** Name of group:
or
BN: **and** Name of firm:

Part 5 – Certification

This form **must** be signed by an authorized person of the business such as an owner, a partner of a partnership, a director of a corporation, an officer of a non-profit organization or a trustee of an estate.
By signing and dating this form, you authorize the CRA to deal with the individual, group, or firm listed in Part 2 of this form or cancel the authorizations listed in Part 4.

First name: BRIAN Last name: D'AMBOISE

Signature: ► Date : 2013-06-21

The CRA will not process this form unless it is signed **and** dated by an authorized person of the business.
This form must be received by the CRA within six months of its signature date.
If it is not received in this time it will not be processed and will be returned to the business.

Privacy Act, Personal Information Bank numbers CRA PPU 175.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2013-12-31

Business number 86585 8773 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2013-01-31	12,438				12,438
2013-02-28	12,438				12,438
2013-03-31	12,438				12,438
2013-04-30	12,438				12,438
2013-05-31	12,438				12,438
2013-06-30	12,438				12,438
2013-07-31	12,438				12,438
2013-08-31	12,438				12,438
2013-09-30	12,438				12,438
2013-10-31	12,438				12,438
2013-11-30	12,438				12,438
2013-12-31	12,433				12,433
Totals	149,251				149,251

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) 001 86585 8773 RC0001

Corporation's name
002 BRANTFORD POWER INC.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 84 MARKET SQUARE
012 P.O. BOX 308
City: 015 BRANTFORD
Province, territory, or state: 016 ON
Country (other than Canada): 017 CA
Postal code/Zip code: 018 N3T 5N8

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 84 MARKET SQUARE
032 P.O. BOX 308
City: 035 BRANTFORD
Province, territory, or state: 036 ON
Country (other than Canada): 037 CA
Postal code/Zip code: 038 N3T 5N8

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 ________ YYYY MM DD

To which tax year does this return apply?
Tax year start: 060 2012-01-01 (YYYY MM DD)
Tax year-end: 061 2012-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . 065 ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . 064 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . 079 ________

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

Question	Line	Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134
Did the corporation have any controlled foreign affiliates?	258		T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Question	Line	1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product/service	Line	%
284	ELECTRICITY DISTRIBUTION	285	100.000 %
286		287	%
288		289	%

Question	Line	1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

	Line	Amount		Line	Amount	
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.				300	587,043	A
Deduct: Charitable donations from Schedule 2	311	2,700				
Gifts to Canada, a province, or a territory from Schedule 2	312					
Cultural gifts from Schedule 2	313					
Ecological gifts from Schedule 2	314					
Gifts of medicine from Schedule 2	315					
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320					
Part VI.1 tax deduction*	325					
Non-capital losses of previous tax years from Schedule 4	331					
Net capital losses of previous tax years from Schedule 4	332					
Restricted farm losses of previous tax years from Schedule 4	333					
Farm losses of previous tax years from Schedule 4	334					
Limited partnership losses of previous tax years from Schedule 4	335					
Taxable capital gains or taxable dividends allocated from a central credit union	340					
Prospector's and grubstaker's shares	350					
Subtotal		2,700	►		2,700	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")					584,343	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions				355		D
Taxable income (amount C **plus** amount D)				360	584,343	
Income exempt under paragraph 149(1)(t)				370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)					584,343	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	587,043	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	584,343	B
Business limit (see notes 1 and 2 below)	410		C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x (415 ***** 153,328 D) / 11,250 = ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = 430 ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			584,343	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income** 432		D		
Amount used to calculate the credit union deduction from Schedule 17		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6***		G		
Total of amounts B to G		▶		H
Amount A **minus** amount H (if negative, enter "0")			584,343	I

Amount I	584,343	x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	J
Amount I	584,343	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x	11.5 %	=	K
Amount I	584,343	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x	13 %	= 75,965	L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L . . . 75,965 M
Enter amount M on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Personal service business income* 434		Q		
Amount used to calculate the credit union deduction from Schedule 17		R		
Total of amounts O to R		▶		S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x	11.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x	13 %	=	W

General tax reduction – Total of amounts U to W . . . X
Enter amount X on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440		x 26 2/3 % =		A
Foreign non-business income tax credit from line 632 on page 7					
Deduct: Foreign investment income from Schedule 7	445		x 9 1/3 % =		
			(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360 on page 3			584,343		
Deduct: Amount from line 400, 405, 410, or 425 on page 4, whichever is the least					
Foreign non-business income tax credit from line 632 on page 7		x 100 / 35 (25/9*) =			
Foreign business income tax credit from line 636 on page 7		x 1(0.38 - X**) / 4 =			
			584,343		
			x 26 2/3 % =	155,825	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)				87,651	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450				F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
				H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	750,000	x 1 / 3	250,000	I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)				

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %		550	222,050	A
Recapture of investment tax credit from Schedule 31		602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	584,343		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	584,343 ▶	584,343	ii

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** amounts A to C)		222,050	D

Deduct:

Small business deduction from line 430 on page 4			1	
Federal tax abatement	608	58,434		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount M on page 5	638	75,965		
General tax reduction from amount X on page 5	639			
Federal logging tax credit from Schedule 21	640			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652			
Subtotal		134,399	▶ 134,399	E

Part I tax payable – Amount D **minus** amount E	87,651	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7			700	87,651
Part II surtax payable from Schedule 46			708	
Part III.1 tax payable from Schedule 55			710	
Part IV tax payable from Schedule 3			712	
Part IV.1 tax payable from Schedule 43			716	
Part VI tax payable from Schedule 38			720	
Part VI.1 tax payable from Schedule 43			724	
Part XIII.1 tax payable from Schedule 92			727	
Part XIV tax payable from Schedule 20			728	
			Total federal tax	87,651

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	61,600		
Provincial tax on large corporations (Nova Scotia Schedule 342)	765			
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		61,600 ▶		61,600
			Total tax payable 770	149,251 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780			
Dividend refund from page 6	784			
Federal capital gains refund from Schedule 18	788			
Federal qualifying environmental trust tax credit refund	792			
Canadian film or video production tax credit refund (Form T1131)	796			
Film or video production services tax credit refund (Form T1177)	797			
Tax withheld at source	800			
Total payments on which tax has been withheld 801				
Provincial and territorial capital gains refund from Schedule 18	808			
Provincial and territorial refundable tax credits from Schedule 5	812			
Tax instalments paid	840	512,940		
Total credits	890	512,940 ▶		512,940 B

Refund code **894** 1 Overpayment 363,689

Balance (amount A **minus** amount B) -363,689

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment **898**

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information **910** ______ Branch number

914 ______ Institution number **918** ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . **896** 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . **920** A5619

Certification

I, **950** D'AMBOISE (Last name (print)) **951** BRIAN (First name (print)) **954** CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2013-06-21 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation **956** (519) 751-3522 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . **957** 1 Yes ☒ 2 No ☐

958 ______ Name (print) **959** ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. **990** 1

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Total instalments for 2012	512,940
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	512,940 **A**
	Total instalments credited to the taxation year per T9	512,940 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	34,508,159	28,634,115
	Total tangible capital assets	2008	+	59,942,622	59,873,172
	Total accumulated amortization of tangible capital assets	2009	–		
	Total intangible capital assets	2178	+	3,562,397	3,479,311
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	7,966,751	7,452,973
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	105,979,929	99,439,571
	Liabilities				
	Total current liabilities	3139	+	16,973,892	14,303,812
	Total long-term liabilities	3450	+	53,864,408	50,857,627
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	70,838,300	65,161,439
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	35,141,629	34,278,132
	Total liabilities and shareholder equity	3640	=	105,979,929	99,439,571
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	12,955,971	12,358,906

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	18,765,130	16,350,948
	Cost of sales	8518	–		
	Gross profit/loss	8519	=	18,765,130	16,350,948
	Cost of sales	8518	+		
	Total operating expenses	9367	+	17,492,707	13,901,936
	Total expenses (mandatory field)	9368	=	17,492,707	13,901,936
	Total revenue (mandatory field)	8299	+	19,336,802	16,961,582
	Total expenses (mandatory field)	9368	–	17,492,707	13,901,936
	Net non-farming income	9369	=	1,844,095	3,059,646
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	1,844,095	3,059,646
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	176,966	-258,596
	Future (deferred) income tax provision	9995	–	320,064	1,028,630
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,347,065	2,289,612

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes checklist

Corporation's name	Business number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Question	Line	1 Yes	2 No
Does the accountant have a professional designation?	095	X	
Is the accountant connected* with the corporation?	097		X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Option	No.	
Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Question	Line	1 Yes	2 No
Has the accountant expressed a reservation?	099		X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Option	No.	
Prepared the tax return (financial statements prepared by client)	1	X
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Question	Line	1 Yes	2 No
Were notes to the financial statements prepared?	101	X	

If **yes**, complete lines 104 to 107 below:

Question	Line	1 Yes	2 No
Are subsequent events mentioned in the notes?	104	X	
Is re-evaluation of asset information mentioned in the notes?	105		X
Is contingent liability information mentioned in the notes?	106	X	
Is information regarding commitments mentioned in the notes?	107	X	
Does the corporation have investments in joint venture(s) or partnership(s)?	108		X

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . **255** 1 Yes [X] 2 No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . **260** 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

Name: BRANTFORD POWER INC.

BN: 86585 8773 RC 0001

Tax Year Start: 2012-01-01

Tax Year End: 2012-12-31

Brantford Power Inc.

Notes to the Financial Statements

for the year ended December 31, 2011

1. Incorporation

On March 1, 2000, Brantford Power Inc. (the Company) was incorporated under
the Business
Corporations Act (Ontario) along with its affiliate companies, Brantford Hydro
Inc. and
Brantford Energy Corporation. Another affiliated company, Brantford Generation
Inc., was
incorporated in 2007. The incorporations were pursuant to the provisions of
the Energy
Competition Act, 1998. The Company is a wholly-owned subsidiary of Brantford
Energy
Corporation. The Company provides electricity distribution services to
residents of the City of
Brantford. The operations of the company are regulated by the Ontario Energy
Board (OEB).

2. Accounting Policies

Basis of accounting

The financial statements of the Company have been prepared in accordance with
Canadian
generally accepted accounting principles (GAAP) and policies as set forth in
the Accounting
Procedures Manual issued by the OEB under the authority of the Ontario Energy
Board Act,
1998. Significant accounting policies are summarized below:

Regulation

The Company is regulated by the OEB and requires OEB approval for any distribution service

rate adjustments. The following accounting policies applicable to rate

regulated operations

differ from GAAP for companies operating in an unregulated environment:

Regulatory assets and liabilities

Regulatory assets primarily represent costs that have been deferred because

they are

expected to be recovered in future rates. Similarly, regulatory liabilities

can arise from

differences in amounts billed to customers under the regulated pricing

mechanism and the

corresponding wholesale market cost of power incurred by the utility.

Regulatory assets and liabilities will be recognized for rate-setting and

financial statement

purposes only to the extent allowed by the regulator. The Company continually

assesses

the likelihood of recovery of each of its regulatory assets and continues to

believe that it is

probable that the OEB will factor its regulatory assets and liabilities into

the setting of

future rates. If, at some future date, the Company judges that it is no longer

probable that

the OEB will include a regulatory asset or liability in future rates, the

appropriate carrying

amount will be reflected in the results of operations in the period that the

assessment is

made. Asset and liability balances and current year activities are detailed in

Note 8.

Page 10

2. Accounting Policies - continued

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions towards the cost of constructing company assets. Capital contributions for the year of $265,560 (2010 - $196,588) have been recorded as an offset to capital assets. Amortization of contributed capital is recorded at an equivalent rate to that used for amortization of the related assets.

Allowance for use of funds during construction

The company capitalizes an allowance for use of funds during construction representing the cost of funds during the construction period. The rate used is prescribed by the OEB and updated on a quarterly basis. The total allowance for use of funds during construction capitalized for the year amounted to $56,469 (2010 - $63,402).

Stranded meters

As a result of the OEB's smart meter initiative, the Company has removed conventional meters and replaced them with smart meters. The net book value of the conventional meters removed from service prior to the end of their useful life has been classified as stranded meters and reallocated from property, plant and equipment to intangible assets.

The OEB will allow the Company to recover the costs of these stranded meters
through a
future rate application process.
Payment in lieu of income taxes
The Company is currently exempt from taxes under the Income Tax Act (Canada)
and the
Ontario Corporations Tax Act. Under the Electricity Act, 1998, the Company is
required to
make payments in lieu of corporate taxes (PILS) to the Ontario Electricity
Financial
Corporation (OEFC), beginning on October 1, 2001. These payments are recorded
in
accordance with the rules for computing income and taxable capital and other
relevant amounts
contained in the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario)
and modified
by the Electricity Act, 1998, and related regulations.
The Company uses the asset and liability method of accounting for payments in
lieu of
corporate income taxes. Accordingly, future tax assets and liabilities are
recognized for future
tax consequences attributable to differences between the financial statement
carrying amounts
of existing assets and liabilities and their respective tax rates. Future tax
assets and liabilities
are measured using enacted or substantively enacted tax rates expected to
apply to taxable
income in the year in which those temporary differences are expected to be

recovered or settled.

In addition, the effect of future tax assets and liabilities of a change in

tax rates is recognized in

income in the year that includes the enactment or substantive enactment date.

Page 11

2. Accounting Policies - continued

Use of estimates

The preparation of financial statements in conformity with Canadian GAAP

requires

management to make estimates and assumptions that affect the reported amounts

of assets and

liabilities and the disclosure and contingent assets and liabilities at the

date of the financial

statements and the reported amounts of revenues and expenses for the year.

During the years

presented, management has made a number of estimates and valuation assumptions

including

allowance for doubtful accounts receivable, unbilled revenue, useful lives,

certain accruals,

valuation of financial instruments including derivatives and future income tax

liabilities.

Estimates are based on historical experience, current trends and various other

assumptions that

are believed to be reasonable under the circumstances. Actual results could

differ from

estimates, including changes as a result of future decisions made by the OEB

or the Minister of

Energy.

Cash and cash equivalents

Cash and cash equivalents include cash and short-term investments with
maturities of three
months or less from the date of acquisition.

Inventories

Inventories consist of repair parts, supplies and materials and are valued at
the lower of cost or
net realizable value determined using a weighted average method. The Company
classifies
major construction related components of its electricity distribution system
to property, plant
and equipment.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the
last meter
reading during the year to the balance sheet date.

Page 12

2. Accounting Policies - continued

Property, plant and equipment

Property, plant and equipment are stated at cost and removed from the accounts
when disposed
or retired. Costs of assets which are pooled are removed from the accounts at
the end of their
estimated average service lives. Gains or losses at retirement or disposition
of such assets are
credited or charged to other income. Amortization is calculated on a straight-
line basis over the
estimated useful service life as follows.

Buildings 50 years

Transformer station 40 years

Distribution stations 30 years

Distribution lines - overhead 25 years

Distribution lines - underground 25 years

Distribution transformers 25 years

Distribution meters 25 years

Vehicles 5-8 years

Tools and other equipment 5-10 years

Capital contribution 25 years

Other electric plant and work in progress are amortized when put in service.

Intangible assets

Intangible assets are recorded at cost and amortized over their estimated
useful lives on a
straight-line basis. Stranded meters represent distribution meters that have
been replaced with
smart meters and reallocated from property, plant and equipment. The OEB has
allowed these
retired meters to remain in rate base for rate making purposes. Amortization
is calculated on a
straight-line basis over the estimated useful service life as follows.

Stranded meters 25 years

Software 5 years

Page 13

2. Accounting Policies - continued

Long-term prepaid expenses and special deposits

Long-term prepaid expenses consist of service fees paid providing the Company
with the right

to use non-owned specified tangible assets for future periods. These charges
are amortized on a
straight-line basis over 10 years representing the expected benefit period.
Amounts are recorded as special deposits when cash is collected related to
customer deposits
and are expected to be held for a period exceeding one year.
Revenue recognition
Distribution revenue is recorded as revenue in the period to which it relates.
Distribution
revenue includes an estimated accrual for the variable component of the
distribution rate based
on the electricity delivered but not yet billed to customers from the last
meter reading date to
the year end.
Other revenue is recognized as services are rendered or contract milestones
are achieved.
Impairment of long-lived assets
The Company reviews the valuation of long-term assets when events or changes
in
circumstances indicate that the assets' carrying value exceeds the total
undiscounted cash flows
expected from their use and eventual disposition. There was no impact on the
financial
statements as a result of asset impairments for the years ended December 31,
2011 and 2010.
Customer deposits
Customer deposits are cash collections from customers to guarantee the payment
of electricity

bills as prescribed by the OEB's Retail Settlement Code. Deposits expected to
be refunded to
customers within the next fiscal period are classified as a current liability.

Employee future benefits

The Company provides post-retirement medical and life insurance benefits to
eligible
employees. The cost of post-retirement medical and life insurance benefits is
expensed using
the projected benefit cost method prorated on services.

The Company has adopted the corridor method of accounting for the actuarially
determined
gains and losses. Cumulative gains and losses in excess of 10% of the
beginning accrued
benefit obligation are amortized into expense on a straight-line basis over
the expected
remaining lifetime of the inactive members receiving benefits under the plan
(15 years).

Page 14

2. Accounting Policies - continued

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from
acquisition,
construction, development or normal operations. The liability for an asset
retirement is initially
recorded at its fair value in the year in which it is incurred and when a
reasonable estimate of
fair value can be made. The corresponding cost is capitalized as part of the
related asset and is

amortized over the asset's useful life. In subsequent years, the liability is
adjusted for changes
resulting from the passage of time and revisions to either the timing or the
amount of the
original estimate of the undiscounted cash flows. Any adjustment to the
liability of its fair
value as a result of the passage of time is charged to earnings.

Comprehensive Income

CICA Handbook Section 1530 requires the presentation of comprehensive income
and its
components in a financial statement. Comprehensive income is composed of the
Company's net
income and other comprehensive income (OCI), which includes unrealized gains
and losses on
changes in the fair value of the effective portion of cash flow hedging
instruments. The
Company discloses comprehensive income in the financial statement "Statement
of
Comprehensive Income". The cumulative changes in OCI are included in
Accumulated other
comprehensive income net of tax (AOCI), which is presented as a category of
Shareholder's
equity on the Company's Balance Sheet.

Financial Instruments

The Corporation designates its financial instruments in one of the following
five categories: (i)
held for trading (HFT); (ii) available for sale (AFS); (iii) held to maturity
(HTM); (iv) loans and

receivables (LR); or (v) other liabilities (OL). All financial instruments are
initially measured at
fair value. Financial instruments classified as held for trading or available
for sale are
subsequently measured at fair value, with any change in fair value recognized
in earnings and
other comprehensive income, respectively. All other financial instruments are
subsequently
measured at amortized cost.

The Company has elected to add transaction costs related to financial
instruments classified as
other than HFT to the carrying amount of the financial instrument.

The Company has elected to use settlement-date accounting for regular-way
purchases and sales
of financial assets.

Page 15

3. Future Changes in Accounting Framework

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed
that publicly
accountable enterprises would be required to adopt IFRS in place of Canadian
GAAP effective
January 1, 2011. Subsequently, in September 2010, the AcSB issued an optional
one year
deferral in adoption of IFRS for rate-regulated entities. The Company
qualifies for this deferral
and has elected to defer adoption until January 1, 2012. The adoption date of
January 1, 2012

will require the restatement, for comparative purposes, of amounts reported by

the Company for

its year ended December 31, 2011, and of the opening balance sheet as at

January 1, 2011.

The Company is continuing to assess the financial reporting impacts of the

adoption of IFRS on

its financial statements. The Company does anticipate significant changes to

those accounting

policies which are unique to rate regulated entities under Canadian GAAP. In

particular, the

adoption of IFRS is expected to result in significant changes to the

accounting of regulatory

assets and liabilities and to the capitalization and other accounting policies

applicable to self

constructed property, plant and equipment. The Company also anticipates a

significant increase

in disclosure resulting from the adoption of IFRS and is continuing to assess

the level of

disclosure required. At this time, the preliminary impact on the Company's

2011 financial

position and results of operations is expected to be a reduction of pre-tax

income by

approximately $2,500,000 related to rate regulation, capitalization policy

changes, useful life

changes and changes in the treatment of employee future benefits.

4. Rate Setting

The rates of the Company's electricity distribution business are subject to

regulation by the

OEB. The Company purchases electricity from the Independent Electricity System
Operator
(the IESO) at spot market or prescribed rates and charges its customers
unbundled rates. The
unbundled rates include the actual cost or prescribed cost of the electricity,
transmission,
wholesale market service charges and an approved rate for electricity
distribution. The cost of
electricity transmission and connection charges and debt retirement charges
are collected by
Brantford Power Inc. and remitted to the IESO and the Ontario Electricity
Financial
Corporation (the OEFC) respectively. The Company retains the distribution
charges reflected
on the customer billings. The distribution charges also incorporate, where
applicable, OEB
approved rate adders or riders that are necessary to dispose of regulatory
assets and liabilities.

Page 16

4. Rate Setting - continued

The OEB has the general power to include or exclude costs, revenues, losses or
gains in the
distribution rates of a specific period, resulting in a change in the timing
of accounting
recognition from that which would have applied in an unregulated company. Such
change in
timing gives rise to the recognition of regulatory assets and liabilities. The
Company's

regulatory assets represent certain amounts receivable from customers in the
future and costs
that have been deferred for accounting purposes because it is probable that
they will be
recovered in future rates. In addition, the Company has recorded regulatory
liabilities which
represent amounts of expenses incurred in different periods than would be the
case had the
company been unregulated.

Specific regulatory assets and liabilities are disclosed in note 8.

In the absence of rate regulation, distribution revenue would have been lower
by $3,367,713
(2010 - $1,707,866), cost of power would have been lower by $985,278 (2010 -
$3,753,601),
other income would have been lower by $14,601 (2010 - $16,144), distribution
operations and
maintenance would have been higher by $51,216 (2010 - lower by $46,971),
general
administration would have been higher by $57,877 (2010 - $68,032),
amortization would have
been higher by $315,364 (2010 - $373,781), and interest income would have been
higher by
$48,937 (2010 - $43,600). The net effect, in the absence of rate regulation,
is a pre-tax decrease
in net income for 2011 of $2,772,556 (2010 - increase of $1,678,349).

The Company administers several programs through the Ontario Power Authority
(OPA)
conservation project. The revenues and expenses related to these programs are

not subject to
the regulation of the OEB.
On October 21, 2009 the Company filed an application for 2010 rates on the
basis of the OEB's
third generation Incentive Regulation Mechanism (IRM) policy which
incorporates an OEBapproved
formula that considers inflation and efficiency targets. On April 12, 2010,
the OEB
released its decision. This decision included the repayment of $7,650,132 in
regulatory
liabilities over a two year period. The revised rates were approved with an
effective date of
May 1, 2010.
On October 29, 2010 the Company filed an application for 2011 rates also on
the basis of the
OEB's third generation IRM policy. On March 28, 2011, the OEB released its
decision. This
decision included the repayment of $1,192,282 in regulatory liabilities. The
revised rates were
approved with an effective date of May 1, 2011.
Page 17
4. Rate Setting - continued
On November 10, 2011 the Company filed an application for 2012 rates also on
the basis of the
OEB's third generation IRM policy. This application has proposed the repayment
of
$5,841,761 in regulatory liabilities. Included in this total is $2,021,450 in
PILs that resulted

from the OEB PILs proceeding concluded during 2011. The PILs amount was

previously not

reflected in the regulatory liabilities total and will reduce distribution

revenue as it is returned to

the customers. These rates would be effective May 1, 2012. The OEB has not

released its

decision regarding the application.

5. Property, Plant and Equipment

2011 2010

Cost

Accumulated

Amortization

Net Book

Value

Net Book

Value

$ $ $ $

Land 181,961 - 181,961 181,961

Buildings 1,163,732 171,258 992,474 1,015,748

Transformer station 4,507,912 780,833 3,727,079 3,801,417

Distribution stations 74,427 27,544 46,883 49,364

Distribution lines - overhead 28,522,309 9,630,502 18,891,807 18,624,257

Distribution lines - underground 32,009,172 9,026,027 22,983,145 22,225,393

Distribution transformers 17,352,178 5,670,172 11,682,006 11,830,709

Distribution meters 3,988,195 1,014,467 2,973,728 1,984,840

Vehicles 3,033,111 2,142,108 891,003 852,652

Tools and other equipment 800,611 209,499 591,112 640,041

Capital contributions (3,851,573) (684,783) (3,166,790) (3,055,303)

Other utility plant 54,756 - 54,756 51,816

Work in progress 24,008 - 24,008 104,107

87,860,799 27,987,627 59,873,172 58,307,002

6. Intangible Assets

2011 2010

Cost

Accumulated

Amortization

Net Book

Value

Net Book

Value

$ $ $ $

Land rights and easements 5,968 - 5,968 5,968

Stranded meters 5,269,572 2,032,381 3,237,191 4,457,373

Software 435,330 199,178 236,152 84,272

5,710,870 2,231,559 3,479,311 4,547,613

Page 18

7. Related Party Transactions

The Company is a wholly owned subsidiary of Brantford Energy Corporation and

Brantford

Energy Corporation is wholly owned by The Corporation of the City of Brantford

(the City).

Brantford Energy Corporation also owns Brantford Hydro Inc. and Brantford

Generation Inc.

The Company obtains certain administrative and management services from the

City and

Brantford Energy Corporation. The Company also provides services to the City, Brantford

Generations Inc. and Brantford Hydro Inc. These services were made in the

normal course of

business and have been recorded at the exchange amounts.

The Company has entered into a shared services agreement with the City,

whereby the City will

provide administrative, customer care, maintenance and operational services

for the Company.

The exchange amount for these services has been set out in the agreement.

Total charges from

the City under this shared agreement were $8,063,255 (2010 - $8,696,419). As

at December

31, 2011 the balance owing to the City for these services was $1,489,970 (2010

- $1,697,640).

For the year ended December 31, 2011, the Company provided electricity to the

City in the

amount of $5,109,891 (2010 - $5,113,692). The Company also provided other

services to the

City in the amount of $138,410 (2010 - $273,143).

For the year ended December 31, 2011, the Company paid property tax to the

City in the

amount of $16,868 (2010 - $18,887)

The Company obtains management services from Brantford Energy Corporation.

Total charges

for these services were $151,041 (2010 - $124,125). As at December 31, 2011

the balance

owing to Brantford Energy Corporation for these services was $23,312 (2010 -

$11,123).

The Company charges pole rental fees to Brantford Hydro Inc. These rental fees
allow fibre
optic cables to be attached to the Company's distribution assets. Total rental
fees for this access
were $42,532 (2010 - $41,102).
For the year ended December 31, 2011, the Company provided electricity to
Brantford
Generation Inc. in the amount of $104,059 (2010 - $48,091). A long term
customer deposit of
$6,955 (2010 - $7,665) has been paid to the Company from Brantford Generation
Inc.
For the year ended December 31, 2011, the Company purchased electricity from
Brantford
Generation Inc. in the amount of $1,641,833 (2010 - $243,060). As of December
31, 2011 the
balance owing to Brantford Generation was $192,299 (2010 - $36,410).
Page 19
8. Regulatory Assets and Liabilities
Based on existing regulatory orders or the expectation of future regulatory
orders, the Company
has recorded the following amounts, net of income tax and amortization where
applicable,
which are expected to be recovered from or refunded to customers:
2011 2010
$ $
Regulatory assets
Retail Market Settlement
Retail settlement variance account - Global Adjustment - 527,990

Retailer cost variance accounts 339,637 320,955

Other

Smart meters 3,048,342 3,520,157

Distribution revenue rate change 527,214 388,432

Special purpose charge 19,478 136,836

Other regulatory assets 212,657 152,191

Net regulatory assets 4,147,328 5,046,561

Regulatory liabilities

Retail Market Settlement

Retail settlement variance accounts 4,265,592 5,117,572

Retail settlement variance account - Global Adjustment 205,504 -

Other

Regulatory future income tax liability 509,205 466,778

Regulatory liabilities refundable through approved rate

riders 2,349,523 5,425,441

Net regulatory liabilities 7,329,824 11,009,791

Retail settlement variance accounts

The retail settlement variance accounts represent differences between charges

billed to

customers using the prescribed prices as outlined in the OEB's Retail

Settlement Code and the

actual costs billed to Brantford Power Inc. by the IESO.

Retail cost variance accounts

The retailer cost variance accounts represent differences between charges

billed to retailers

using the prescribed prices as outlined in the OEB's Retail Settlement Code

and the actual costs

paid by Brantford Power Inc. to operate and maintain the systems related to the retail market.

Page 20

8. Regulatory Assets and Liabilities - continued

Smart meters

On April 12, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and approved a monthly rate adder charge of $0.28 per metered customer for the Company. Effective May 1, 2009, the OEB increased the monthly adder to $1.00 per metered customer. Effective May 1,2010, the OEB increased the monthly adder to $2.07 per metered customer. Effective May 1, 2011, the OEB maintained the monthly adder at $2.07 per metered customer. In its 2012 application to the OEB, the Company has requested the monthly adder be removed.

The Company has recorded a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder. These expenditures and recoveries will continue to be reported as regulatory assets or liabilities until the Company applies to the OEB to redistribute the amounts to capital or operations.

Distribution revenue rate change

On February 25, 2009, Brant County Power Inc. (BCPI) filed a motion with the OEB to review

and vary the Company's 2008 Electricity Distribution Rates. BCPI disputed the
rates they were
being charged as well as the date that the Company could bill retroactively.
The OEB released
it decision and order related to this motion on August 10, 2010. The decision
allowed the
Company to record a regulatory asset consisting of the revenue deficiency
between the rates
that were approved during the 2008 cost of service application for the
Company's embedded
distributor and the rates that were approved as a result of the BCPI motion.
Special purpose charge
On April 9, 2010, the OEB informed electricity distributors of a Special
Purpose Charge (SPC)
assessment under Section 26.1 of the OEB Act, for the Ministry of Energy and
Infrastructure
conservation and renewable energy program costs. The OEB assessed the Company
the amount
of $376,534 for its apportioned share of the total provincial amount of the
SPC of $53,695,000
in accordance with the rules set out in Ontario Regulation 66/10 (the SPC
Regulation). In
accordance with Section 9 of the SPC Regulation, the Company was allowed to
recover this
balance. The recovery was completed as at April 30, 2011. As at December 31,
2011, the
balance in the account consists of the Company's assessment less the
recoveries received from

customers.

Page 21

8. Regulatory Assets and Liabilities - continued

Regulatory future income tax liability

The Company has recorded a regulatory liability account that relates to the

expected future

electricity distribution rate reduction for customers arising from timing

differences in the

recognition of future tax assets.

Regulatory liabilities refundable through approved rate riders

The regulatory liabilities refundable through approved rate riders consists of

balances of

regulatory assets or regulatory liabilities approved for disposition by the

OEB through rate

riders. The amount is subject to carrying charges following the OEB prescribed

methodology

and related rates.

9. Long-Term Debt

2011 2010

$ $

Note payable, bearing interest at 5.87%, repayable to the

City, interest only payable annually - due February, 2016 24,189,168

24,189,168

Royal Bank, non-revolving term facility with interest at

prime repayable in quarterly instalments, due January,

2013 4,361,278 4,715,635

Royal Bank, non-revolving term facility with interest at

prime repayable in quarterly instalments, due November, 2016 683,657 798,292

Ontario Infrastructure and Lands Corporation nonrevolving

term facility with interest at 5.14% repayable

in semi annual instalments due December, 2032 2,212,664 2,268,400

Ontario Infrastructure and Lands Corporation nonrevolving

term facility with interest at 4.95% repayable

in semi annual instalments due December, 2050 4,769,966 4,808,821

Ontario Infrastructure and Lands Corporation construction

advances with interest at 1.75% (2010 - 1.54%) 5,301,704 4,750,364

41,518,437 41,530,680

Less current portion 598,986 1,250,304

40,919,451 40,280,376

Page 22

9. Long-Term Debt - continued

The City has an option to extend the maturity date of the promissory note for

successive five

year periods. The City also has the option to convert the principal sum

outstanding into

common shares of the Company at a conversion ratio of $ 100 per common share.

Interest

payable to the City of $1,427,564 (2010 - $1,511,823) was outstanding as at

December 31,

2011.

The Company entered into a swap agreement during 2006 with Royal Bank to hedge

against

exposure to interest rate fluctuations. The agreement represents a notional

principal amount of

$ 5,900,000. Under the terms of the agreement, the company has contracted to pay interest at a

fixed rate of 4.71% while receiving a variable rate equivalent to the one

month Canadian Dollar

Offered Rate to be repriced quarterly.

The Company entered into a second swap agreement during 2006 with Royal Bank

to hedge

against exposure to interest rate fluctuations. The agreement represents a

notional principal

amount of $ 1,200,000. Under the terms of the agreement, the company has

contracted to pay

interest at a fixed rate of 4.97% while receiving a variable rate equivalent

to the one month

Canadian Dollar Offered Rate to be repriced quarterly.

These credit facilities are secured by general security agreement over all

assets of the Company

and an assignment of related fire insurance.

Estimated principal repayment requirements are as follows:

$

2012 598,986

2013 4,230,214

2014 249,710

2015 263,489

2016 24,466,732

Thereafter 11,709,306

Page 23

10. Employee Future Benefits

The Company acquired various life insurance, health care related and dental

coverage plan

liabilities for certain retired employees of the former Hydro-Electric
Commission of the City of
Brantford. Travel, dental, vision and semi-private health care coverage is
continued until the
retiree reaches 65 years of age. Life insurance and extended health care
coverage is continued
until the retiree's death. The Company is also obligated to provide post
retirement benefits to
an active employee.
The Company measures the accrued benefit obligation for accounting purposes as
of December
31 of each year. The accrued benefit obligation as at December 31, 2011 and
the expense for
the period ended December 31, 2011 are based on an actuarial valuation done as
at January 1,
2008.
The obligation is unfunded since no assets have been segregated and restricted
to provide the
post-retirement benefits.
Significant Assumptions
The key weighted-average assumptions used by the Company for the measurement
of the
benefit obligation and benefit expense are summarized as follows:
2011 2010
$ $
To determine benefit obligation at end of year
Discount rate 3.25% 4.5%
Assumed long-term rate of return on assets N/A N/A

To determine benefit expense (income) for the year

Discount rate 4.5% 5.0%

Assumed long-term rate of return on assets N/A N/A

Rate of increase in future compensation N/A N/A

Health care cost trend rates at end of year

Initial rate 6.45% 7.30%

Ultimate rate 4.75% 4.75%

Year ultimate rate reached 2013 2013

Sensitivity Analysis Change in

Obligation

Change in

Expense

$ $

Impact of 1% increase in assumed health care trend rate 119,000 13,000

Impact of 1% decrease in assumed health care trend rate (103,000) (11,000)

Page 24

10. Employee Future Benefits - continued

2011 2010

$ $

Change in benefit obligation

Benefit obligation at beginning of year 1,810,444 1,713,447

Interest cost on benefit obligation 80,151 85,054

Benefits paid (58,616) (24,737)

Actuarial (gain) loss on accrued benefit obligation (68,747) 36,680

Benefit obligation at end of year 1,763,232 1,810,444

Change in fair value of assets

Fair value of assets at beginning of year - -

Employer contributions 58,616 24,737

Benefits paid (58,616) (24,737)

Fair value of assets at end of year - -

Reconciliation of funded status to accrued benefit

liability

Deficit of fair value of assets over benefit obligation at end

of year 1,763,232 1,810,444

Unamortized actuarial loss (786,653) (916,705)

Accrued benefit liability at end of year 976,579 893,739

Reconciliation of accrued benefit liability

Accrued benefit liability at beginning of year 893,739 774,365

Benefit expense recognized 141,456 144,111

Benefits paid (58,616) (24,737)

Accrued benefit liability at end of year 976,579 893,739

Annual benefit expense

Interest cost on benefit obligation 80,151 85,054

Actuarial loss 61,305 59,057

Benefit expense recognized 141,456 144,111

Cash payments

Benefit premiums paid 91,633 86,464

Page 25

11. Contingencies and Commitments

General Liability Insurance

The Company has obtained general liability and enhanced directors and officers

insurance

coverage from the Municipal Electric Association Reciprocal Insurance Exchange

(The Mearie

Group) expiring January 1, 2013. The Mearie Group is an insurance reciprocal

whereby all

members through the unincorporated group share risks with each other. Members of the Mearie

Group are assessed a premium deposit at policy execution. Should the group experience losses

that are in excess of the accumulated premium deposits of its members combined with reserves

and supplementary insurance, members would be assessed a supplementary or retro assessment

on a pro-rata basis for the years in which the Company was a member.

As at December 31, 2011, the Company has not been made aware of any additional assessments. Participation in The Mearie Group covers a three year underwriting period which

expires on January 1, 2013.

Smart Meter Initiative

The OEB has mandated that the Company is to bill Time of Use Prices using "Smart Meter"

electricity meters and the Provincial Meter Data Management/Repository effective July 2011.

The Company was granted an extension of the effective date to December 2011.

The Company has installed approximately 37,134 (2010 - 35,255) Smart Meters as of the end

of 2011 and anticipates having installed a total of 37,240 Smart Meters upon completion of its

mass deployment.

12. Subsequent Event

During December 2011, the City announced plans to restructure the Company to better meet the

Affiliate Relationship Code of the OEB. The major change relates to approximately 60 staff

members currently employed by the City becoming employees of the Company. The

restructuring will be effective April 1, 2012. At this time, the impact on the

Company's future

financial position and results of operations is not reasonably determinable or

estimable.

13. Share Capital

Authorized

Unlimited number of common shares

2011 2010

$ $

Issued

1,001 common shares 22,437,505 22,437,505

Page 26

14. Accumulated Other Comprehensive Loss

2011 2010

$ $

Balance at beginning of year (374,658) (342,478)

Other comprehensive loss, net of tax (143,621) (32,180)

Balance at end of year, net of tax (518,279) (374,658)

15. Pension Plan

The Company participates in the Ontario Municipal Employees Retirement System

(OMERS),

a multi-employer plan, on behalf of its employee. The plan is a contributory

defined benefit

pension plan. Contributions are 7.4% for employee earnings below the year's

maximum

pensionable earnings and 10.7% thereafter. The contribution rates are expected to change to

8.3% for employee earnings below the year's maximum pensionable earnings and

12.8%

thereafter for 2012. During 2011, the Company expensed contributions totaling

$Nil (2010 -

$11,554) made to OMERS in respect of the employer's required contributions to

the plan as its

employee had reached 35 years credited service in the OMERS plan.

Page 27

16. Electricity Distribution Service Charges

The company is licensed by the OEB to distribute electricity. As a licensed

distributor, the

Company is responsible for billing customers for electricity generated by

third parties and the

related costs of providing electricity service, such as transmission services

and other services

provided by third parties. The Company is required, pursuant to regulation, to

remit such

amounts to these third parties, irrespective of whether the Company ultimately

collects these

amounts from customers. The Company may file to recover uncollected debt

retirement

charges from OEFC once each year. Otherwise, the Company is unable to recover

uncollected

amounts formerly remitted to these third parties. The Company retains only its

electricity

distribution service charge that is regulated by the OEB.

Electricity distribution service charges comprise:

2011 2010

$ $

Gross customer billings 105,109,712 102,691,543

Less pass through charges billed by the Company

Electricity charges paid through to generators (66,724,020) (62,528,186)

Transmission and miscellaneous charges (10,618,115) (12,192,434)

Market service charges (6,186,857) (6,234,467)

Debt retirement charges (6,422,286) (6,442,494)

Total electricity distribution service charges 15,158,434 15,293,962

17. Statement of Cash Flows

2011 2010

$ $

Changes in non-cash working capital

Accounts receivable 1,109,739 (1,329,770)

Unbilled revenue 358,818 617,437

Inventories 100,514 48,853

Prepaid expenses 39,379 (6,769)

Accounts payable and accrued liabilities (1,465,361) 874,241

Accounts payable to the City of Brantford (207,670) 42,758

Interest payable to the City of Brantford (84,259) -

Due to affiliates 226,604 20,653

Payments in lieu of corporate income taxes (677,733) 266,625

(599,969) 534,028

Page 28

18. Amortization

2011 2010

$ $

Amortization of capital assets 3,842,300 3,374,841

Amortization of capital assets charged to distribution

operations and maintenance 271,416 266,240

4,113,716 3,641,081

19. Capital Disclosures

The Company's main objectives when managing capital are to:

" ensure ongoing access to funding to maintain and improve the electricity

distribution system;

" ensure compliance with covenants related to its credit facilities; and

" align its capital structure with the debt to equity structure deemed by the

OEB.

As at December 31, 2011, the Company's definition of capital includes

shareholder's equity and

long-term debt. This definition remains unchanged from prior years. As at

December 31,

2011, shareholder's equity amounts to $34,278,132 (2010 - $33,582,141) and

long-term debt,

amounts to $41,518,437 (2010 - $41,530,680). The Company's capital structure

as at

December 31, 2011 is 55% debt and 45% equity (2010 - 55% debt and 45% equity).

There

have been no changes in the Company's approach to capital management during

the year.

The Company's long-term debt agreements include both financial and non-

financial covenants.

As at December 31, 2011 and as at December 31, 2010, the Company was in

compliance with

all covenants.

Page 29

20. Financial Instruments

All financial instruments are initially recorded on the balance sheet at fair value except for
certain related party transactions. They are subsequently valued either at fair value or amortized
cost depending on the classification selected by the Company for the financial instrument. All
financial instruments are classified into one of the five categories: held-for -trading, loans and
receivables, other liabilities, held-to-maturity investments or available-for-sale financial assets

Held-for-trading (HFT) financial instruments are financial assets and financial liabilities
typically acquired with the objective of resale or short-term buyback. The carrying amount is
recorded at fair value determined using market prices. Interest earned and gains and losses
incurred are recognized in net income. Cash and cash equivalents and special deposits are
designated as financial assets held-for-trading and are measured at fair value with changes
being recorded in net income at each period end. Derivative liabilities are designated as
financial liabilities held-for-trading and are measured at fair value with changes being recorded
in other comprehensive income at each period end.

Loans and receivables (LR) are non-derivative financial assets resulting from the delivery of cash or other assets by a lender to a borrower in return for a promise to repay on a specified date, or on demand, usually with interest. Loans and receivables are measured at amortized cost. Accounts receivable and unbilled revenue are classified as loans and receivables and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost.

Other liabilities (OL) are promises to repay on specified dates or on demand usually with interest. Accounts payable and accrued liabilities and accounts payable to the City of Brantford, interest payable to the City of Brantford and due to affiliates are classified as other liabilities and are measured at fair value at inception, which due to their short-term nature, approximates amortized cost. Long-term debt and customer deposits are also classified as other liabilities.

After their initial fair value measurement, they are measured at amortized cost using the effective interest rate method.

Held-to-maturity (HTM) financial assets have fixed or determinable payments and maturity, and management's intention and ability are to hold to maturity. These financial assets are measured at amortized cost. The Company does not hold any financial assets under this classification.

Available-for-sale (AFS) instruments are non-derivative financial assets that

are designated as

available-for-sale or that are not classified as loans and receivables, held-

to-maturity

investments or held-for-trading financial assets. Available-for-sale

instruments are measured at

fair value with unrealized gains and losses recognized in OCI. The Company

does not hold any

financial assets under this classification.

Page 30

20. Financial Instruments - continued

Interest Rate Risk

Interest is paid on customer deposits at a market rate reset quarterly as

directed by the Ontario

Energy Board.

Two term facility loans bear interest at floating rates and thus, the carrying

values approximate

fair values. However, the Company has entered into two interest rate swap

transactions,

derivative instruments designated as a cash flow hedges, the effect of which

is to fix the interest

rate on the first $4,369,000 term facility loan at 4.71% and the second

$686,000 term facility

loan at 4.97%. The potential replacement cost to Brantford Power Inc. of the

interest rate

swaps, representing estimated fair value as presented on the balance sheet,

was $713,683 (2010

- $525,435), which was in the favour of Royal Bank. Net unrealized loss in fair value of
$191,491 (2010 - $42,910) is presented in current year Other Comprehensive Loss. The
Company entered into these interest rate swap transactions to fix the interest rates over the long
term and intends to hold these to maturity at which time there should be no replacement cost.

Credit Risk

The Company grants credit to its customers in the normal course of business and monitors their
financial condition and reviews the credit history of new customers. The Company is currently
holding customer deposits on hand in the amount of $2,073,612 (2010 - $2,508,520) which is
reflected on the Balance Sheet. Customer deposits are limited to those allowed under the
OEB's Retail Settlement Code. Allowances of $680,000 (2010 - $608,000) are also maintained
for potential credit losses. The Company's accounts receivable do not reflect the concentrated
risk of default from exposure to large customers. At December 31, 2011, the outstanding
amounts receivable from the largest ten customers represented $1,923,019 or 27% (2010 -
$2,426,830 or 29%) of the total outstanding accounts receivable. Management believes that it
has adequately provided for any exposure to normal customer and retailer

credit risk.

Liquidity Risk

The Company's objective is to have sufficient liquidity to meet its
liabilities when due. The
Company monitors its cash balances and cashflows generated from operations to
meet its
requirements.

Page 31

20. Financial Instruments - continued

Prudential Support

Brantford Power Inc. is required, through the Independent Electricity System
Operator (IESO),
to provide security to mitigate the company's risk of default based on its
expected activity in the
electricity market. The IESO could draw on this guarantee if Company fails to
make a payment
required by a default notice issued by the IESO. The maximum potential payment
is the face
value of the bank letter of credit. As at December 31, 2011, the Company
provided prudential
support in the form of a bank letter of credit of $9,375,721 (2010 -
$9,375,721).

Revolving Term Facility

As at December 31, 2011, the Company has been authorized for a revolving term
facility of
$7,000,000 of which NIL had been drawn upon. The facility bears interest at
prime and is
secured by a general security agreement over all assets of the Company and

assignment of

related fire insurance.

Fair Value of Other Financial Instruments

a) Establishing fair value

The carrying values of cash and cash equivalents, accounts receivable, special

deposits,

accounts payable and accrued liabilities, accounts payable to the City of

Brantford, interest

payable to the City of Brantford, and due to Brantford Energy Corporation

approximate

their fair values due to the immediate or short-term maturity of these

financial instruments.

Fair values for other financial instruments, detailed below, have been

estimated with

reference to quoted market prices for actual or similar instruments where

available, except

for certain related party transactions.

Customer deposits fair value equals carrying value. Interest is paid on

deposits on a

monthly basis at a market rate, reset quarterly, as directed by the Ontario

Energy Board.

The fixed rate long-term debt facility, maturing December 2032, funded by the

Ontario

Infrastructure and Lands Corporation (OILC) has an estimated fair value of

$2,492,700

(carrying value - $2,212,664). The fair value was determined using the present

value of the

cash flows using the quoted OILC market rate for the debt at December 31, 2011, of 3.78%

per annum, (actual rate - 5.14% per annum). The loan is classified as an Other

Liability

(OL) with no resulting adjustment to carrying value.

Page 32

20. Financial Instruments - continued

The fixed rate long-term debt facility, maturing December 2050, funded by the

OILC has

an estimated fair value of $5,442,200 (carrying value - $4,769,966). The fair

value was

determined using the present value of the cash flows using the quoted OILC

market rate for

the debt at December 31, 2011, of 4.00% per annum, (actual rate - 4.95% per

annum). The

loan is classified as an Other Liability (OL) with no resulting adjustment to

carrying value.

The promissory note payable to the Corporation of the City of Brantford,

classified as an

OL, is valued at face value. It is not practicable within constraints of

timeliness or cost to

measure reliably the fair value of this financial liability that originated in

a related party

transaction.

Construction advances funded by the OILC, classified as OL are valued at face

value.

Upon completion of construction the term of the loan will be 15 years.

The fair value of derivative instruments is calculated using pricing models

that incorporate

current market prices and the contractual prices of the underlying
instruments, the time
value of money and yield curves.
b) Fair value hierarchy
Financial instruments recorded at fair value on the Balance Sheet are
classified using a fair
value hierarchy that reflects the significance of the inputs used in making
the
measurements. The fair value hierarchy has the following levels:
Level 1 - valuation based on quoted prices (unadjusted) in active markets for
identical
assets or liabilities;
Level 2 - valuation techniques based on inputs other than quoted prices
included in Level 1
that are observable for the asset or liability, either directly (ie as prices)
or indirectly (ie
derived from prices);
Level 3 - valuation techniques using inputs for the asset or liability that
are not based on
observable market data (unobservable inputs).
The fair value hierarchy requires the use of observable market inputs whenever
such inputs
exist. A financial instrument is classified to the lowest level of the
hierarchy for which a
significant input has been considered in measuring fair value.
Page 33
20. Financial Instruments - continued
The following table presents the financial instruments recorded at fair value

in the Balance

Sheet, classified using the fair value hierarchy described above:

Level 1 Level 2 Level 3

Total financial

assets and

liabilities at fair

value

$ $ $ $

Financial Assets

Cash and cash equivalents 9,200,282 - - 9,200,282

Special deposits 2,073,612 - - 2,073,612

Total financial assets 11,273,894 - - 11,273,894

Financial liabilities

Customer deposits 2,073,612 - - 2,073,612

Total financial liabilities 2,073,612 - - 2,073,612

During the year, there has been no transfer of amounts between Level 1 and

Level 2 and no

financial assets or liabilities have been identified as Level 3.

Page 34

21. Payments in Lieu of Corporate Income Taxes

The Company's income tax expense for the year ended December 31, 2011 consists

of the

following:

Temporary differences which give rise to future income tax assets and

liabilities are as follows:

2011 2010

$ $

Regulatory assets 643,641 1,658,807

Cumulative eligible capital 156,910 170,190

Allowance for doubtful accounts 178,500 171,760

Property, plant and equipment 1,063,135 1,047,872

Employee future benefits 244,390 224,150

Unrealized losses on derivative liabilities 171,620 123,750

Future income tax assets 2,458,196 3,396,529

Distributed as such:

Future payments in lieu of corporate income tax asset

Current 178,500 171,760

Non-current 2,279,696 3,224,769

2,458,196 3,396,529

The impact of differences between the Company's reported payments in lieu of

corporate

income taxes and the expense that would otherwise result from the application

of statutory rates

is as follows:

2011 2010

$ $

Income tax expense at the combined basis federal and

provincial statutory tax rate 1,003,091 1,192,799

Net change in regulatory assets 8,794 1,161,325

Capital cost allowance in excess of amortization (140,633) (779,373)

Net change in tax reserves (95,268) 47,254

Tax effect of gain on sale of fixed assets (6,373) (15,831)

Tax effect of expenses that are not deductible for income

tax purposes 423 754

770,034 1,606,928

22. Comparative Figures

Certain prior year figures have been reclassified to conform with the current

year's presentation.

Page 35

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

Assets – lines 1000 to 2599

1000	13,935,062	1060	8,943,997	1066	569,406
1120	1,106,630	1125	8,557,480	1480	1,117,443
1481	180,730	1484	97,411	1599	34,508,159
1900	59,942,622	2008	59,942,622	2010	3,562,397
2178	3,562,397	2420	6,040,439	2421	1,926,312
2589	7,966,751	2599	105,979,929		

Liabilities – lines 2600 to 3499

2620	12,074,178	2622	896,904	2860	328,444
2862	1,419,904	2920	1,137,019	2961	1,117,443
3139	16,973,892	3140	44,179,375	3320	9,685,033
3450	53,864,408	3499	70,838,300		

Shareholder equity – lines 3500 to 3640

3500	22,437,505	3541	141,319	3580	-393,166
3600	12,955,971	3620	35,141,629	3640	105,979,929

Retained earnings – lines 3660 to 3849

3660	12,358,906	3680	1,347,065	3700	-750,000
3849	12,955,971				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

Description

Sequence number 0003 01

Revenue – lines 8000 to 8299

8000	18,765,130	8089	18,765,130	8100	273,775
8230	297,897	8299	19,336,802		

Cost of sales – lines 8300 to 8519

8519	18,765,130

Operating expenses – lines 8520 to 9369

8670	3,595,408	8714	2,163,585	8715	172,775
8960	7,073,330	9284	4,487,609	9367	17,492,707
9368	17,492,707	9369	1,844,095		

Extraordinary items and taxes – lines 9970 to 9999

9970	1,844,095	9990	176,966	9995	320,064
9999	1,347,065				

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			1,347,065	A
Add:				
Provision for income taxes – current	101	176,966		
Provision for income taxes – deferred	102	320,064		
Amortization of tangible assets	104	3,813,949		
Charitable donations and gifts from Schedule 2	112	1,250		
Non-deductible meals and entertainment expenses	121	6,123		
Other reserves on lines 270 and 275 from Schedule 13	125	2,073,612		
Reserves from financial statements – balance at the end of the year	126	4,895,419		
Subtotal of additions		11,287,383 ▶	11,287,383	
Other additions:				
Miscellaneous other additions:				
600 CY cumulative adjusted regulatory asset	290	6,880,490		
604				
Total	294			
Subtotal of other additions	199	6,880,490 ▶	6,880,490	
Total additions	500	18,167,873 ▶	18,167,873	B
Amount A **plus** amount B			19,514,938	
Deduct:				
Gain on disposal of assets per financial statements	401	565		
Capital cost allowance from Schedule 8	403	4,202,996		
Cumulative eligible capital deduction from Schedule 10	405	48,397		
Other reserves on line 280 from Schedule 13	413	1,860,225		
Reserves from financial statements – balance at the beginning of the year	414	3,651,679		
Subtotal of deductions		9,763,862 ▶	9,763,862	
Other deductions:				
Miscellaneous other deductions:				
700 AFUDC	390	27,434		
701 PY cumulative adjusted regulatory assets	391	8,031,724		
703 Capitalized Period Costs — 1,104,875				
Total — 1,104,875	393	1,104,875		
704				
Total	394			
Subtotal of other deductions	499	9,164,033 ▶	9,164,033	
Total deductions	510	18,927,895 ▶	18,927,895	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			587,043	

T2 SCH 1 E (12)

Canada

Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

Description	Amount	
Regulatory Asset per F/S	961,455	00
PPVA @ 9/30/01	-898,000	00
Transition Costs @ 9/30/01	364,437	00
Regulatory Assets capitalized	292,547	00
Global Adjustment reversal	783,497	00
Smart Meter Capital - not in use	5,376,554	00
Total	6,880,490	00

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- For use by corporations to claim any of the following:
  – charitable donations;
  – gifts to Canada, a province, or a territory;
  – gifts of certified cultural property;
  – gifts of certified ecologically sensitive land; or
  – additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  – Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  – If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Wilfred Laurier University	1,000
Subtotal	1,000
Add: Total donations of less than $100 each	250
Total donations in current tax year	1,250

	Line		Federal	Québec	Alberta
Charitable donations at the end of the previous tax year			1,450	1,450	1,450
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the tax year	240		1,450	1,450	1,450
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210	1,250		1,250	
Subtotal (line 250 **plus** line 210)			1,250	1,250	1,250
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available			2,700 A	2,700	2,700
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260		2,700	2,700	2,700
Charitable donations closing balance	280				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31	1,450	1,450	1,450
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
7th prior year	2005-12-31			
8th prior year	2004-12-31			
9th prior year	2003-12-31			
10th prior year	2002-12-31			
11th prior year	2001-12-31			
12th prior year	2000-12-31			
13th prior year	1999-12-31			
14th prior year	1998-12-31			
15th prior year	1997-12-31			
16th prior year	1996-12-31			
17th prior year	1995-12-31			
18th prior year	1994-12-31			
19th prior year	1993-12-31			
20th prior year	1992-12-31			
21st prior year*	1991-12-31			
Total (to line A)		1,450	1,450	1,450

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %			440,282	B
Taxable capital gains arising in respect of gifts of capital property included in Part 1**	225			C
Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01)	227			D
The amount of the recapture of capital cost allowance in respect of charitable gifts	230			
Proceeds of disposition, less outlays and expenses**				E
Capital cost**				F
Amount E or F, whichever is less	235			
Amount on line 230 or 235, whichever is less				G
Subtotal (**add** amounts C, D, and G)				H
Amount H **multiplied** by 25 %				I
Subtotal (amount B **plus** amount I)			440,282	J
Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less)			2,700	K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		▶
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
Subtotal (line 350 **plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	355		
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).	360		
Gifts to Canada, a province, or a territory closing balance	380		

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31			
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
7th prior year	2005-12-31			
8th prior year	2004-12-31			
9th prior year	2003-12-31			
10th prior year	2002-12-31			
11th prior year	2001-12-31			
12th prior year	2000-12-31			
13th prior year	1999-12-31			
14th prior year	1998-12-31			
15th prior year	1997-12-31			
16th prior year	1996-12-31			
17th prior year	1995-12-31			
18th prior year	1994-12-31			
19th prior year	1993-12-31			
20th prior year	1992-12-31			
21st prior year*	1991-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31			
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
7th prior year	2005-12-31			
8th prior year	2004-12-31			
9th prior year	2003-12-31			
10th prior year	2002-12-31			
11th prior year	2001-12-31			
12th prior year	2000-12-31			
13th prior year	1999-12-31			
14th prior year	1998-12-31			
15th prior year	1997-12-31			
16th prior year	1996-12-31			
17th prior year	1995-12-31			
18th prior year	1994-12-31			
19th prior year	1993-12-31			
20th prior year	1992-12-31			
21st prior year*	1991-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

	Line	Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year							
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640						
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

	Line	Federal	Québec	Alberta
Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31			
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2011-12-31	
2nd prior year	2010-12-31	
3rd prior year	2009-12-31	
4th prior year	2008-12-31	
5th prior year	2007-12-31	
6th prior year*	2006-12-31	
7th prior year	2005-12-31	
8th prior year	2004-12-31	
9th prior year	2003-12-31	
10th prior year	2002-12-31	
11th prior year	2001-12-31	
12th prior year	2000-12-31	
13th prior year	1999-12-31	
14th prior year	1998-12-31	
15th prior year	1997-12-31	
16th prior year	1996-12-31	
17th prior year	1995-12-31	
18th prior year	1994-12-31	
19th prior year	1993-12-31	
20th prior year	1992-12-31	
21st prior year*	1991-12-31	
Total		

* These gifts expired in the current year.

T2 SCH 2 E (07)

Canada

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column F3 – Enter if dividends have been received or not after December 20, 2012. This information is required for corporations that must complete Schedules 71 and 72. For more details with regards to this column, consult the Help.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (from which the corporation received the dividend)	A	B Enter 1 if payer corporation is connected	C Business Number of connected corporation	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note)	E Non-taxable dividend under section 83
		Complete if payer corporation is connected			
200		205	210	220	230

Total (enter on line 402 of Schedule 1)

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.
For more details, consult the Help.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)*	F1 Eligible dividends (included in column F)	F2	F3	G Total taxable dividends paid by connected payer corporation (for tax year in column D)	H Dividend refund of the connected payer corporation (for tax year in column D)**	I Part IV tax before deductions F x 1 / 3 ***
				Complete if payer corporation is connected		
240				250	260	270
						J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . .

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax 320

Subtotal

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax 330

Non-capital losses from previous years claimed to reduce Part IV tax 335

Current-year farm loss claimed to reduce Part IV tax 340

Farm losses from previous years claimed to reduce Part IV tax 345

Total losses applied against Part IV tax x 1 / 3 =

Part IV tax payable (enter amount on line 712 of the T2 return) 360

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation	Business Number	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note)	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
	400	410	420	430	
1	Brantford Energy Corporation	87504 1329 RC0001	2012-12-31	750,000	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

Total 750,000

Total taxable dividends paid in the tax year to other than connected corporations 450

Eligible dividends (included in line 450) 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund
(total of column D above **plus** line 450) 460 750,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 750,000

Other dividends paid in the tax year (total of 510 to 540) . . . .

Total dividends paid in the tax year 500 750,000

Deduct:

Dividends paid out of capital dividend account 510

Capital gains dividends 520

Dividends paid on shares described in subsection 129(1.2) 530

Taxable dividends paid to a controlling corporation that was bankrupt
at any time in the year 540

Subtotal ▶

Total taxable dividends paid in the tax year that qualify for a dividend refund 750,000

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
584,343		584,343	67,199

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	67,199			
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal		67,199	►	67,199	A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				67,199	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				67,199	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416				
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				67,199	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)	418				
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				67,199	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				67,199	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	5,599			
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		5,599	►	5,599	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290			61,600	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 61,600

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		1,079,365			0		1,079,365	4	0	0	43,175	1,036,190
2.	8		396,478	38,399		0	19,200	415,677	20	0	0	83,135	351,742
3.	10		729,404	123,836		565	61,636	791,039	30	0	0	237,312	615,363
4.	1		31,413,704			0		31,413,704	4	0	0	1,256,548	30,157,156
5.	47		28,612,233	2,248,770		0	1,124,385	29,736,618	8	0	0	2,378,929	28,482,074
6.	50		137,059	103,440		0	51,720	188,779	55	0	0	103,828	136,671
7.	12			200,139		0	100,070	100,069	100	0	0	100,069	100,070
		Totals	62,368,243	2,714,584		565	1,357,011	63,725,251				4,202,996	60,879,266

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (11) Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		2,714,584		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+	1,104,875		
Other (specify):				
Smart Meters	+	89,344		
Line transformer spares (in inventory, full basis)	+	120,672		
AFUDC Adjustment	+	27,434		
Total additions per books	=	4,056,909	►	4,056,909
Proceeds up to original cost – Schedule 8 regular classes		565		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
Accounting Correction	+	78,915		
Spare parts in inventory	+	77,960		
Total proceeds per books	=	157,440	► –	157,440
Depreciation and amortization per accounts – Schedule 1			–	3,813,949
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	565
Net change per tax return			=	86,085

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		63,167,972
Opening net book value	–	63,085,790
Net change per financial statements	=	82,182

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Financial statements – Fixed assets (excluding land) per financial statements – Closing net book value

Title Financial statements – Fixed assets (excluding land) per financial statemen

Description	Amount	
NBV per F/S	63,505,019	00
Less: Additions to transformers WIP in services		
Less: WIP per FS	-13,086	97
Less: land rights	-87,243	00
Less: other utility plant	-54,756	00
Deduction of capitalized period costs		
Less: land	-181,961	00
Total	63,167,972	03

Attached Schedule with Total

Financial statements – Fixed assets (excluding land) per financial statements – Opening net book value

Title Financial statements – Fixed assets (excluding land) per financial statemen

Description	Amount	
NBV per PY FS	63,352,483	00
Less: PY Land	-181,961	00
Less: PY Land rights	-5,968	00
Less: PY WIP	-24,008	00
Less: PY other utility plant	-54,756	00
Total	63,085,790	00

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	BRANTFORD ENERGY CORPORATIC		87504 1329 RC0001	1					
2.	BRANTFORD GENERATION INC.		83941 2814 RC0001	3					
3.	BRANTFORD HYDRO INC.		87504 1121 RC0001	3					
4.	The Corporation of the City of Brant		12268 6793 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")			200	624,612	A
Add: Cost of eligible capital property acquired during the taxation year	222	89,022			
Other adjustments	226				
Subtotal (line 222 plus line 226)		89,022 x 3 / 4 =	66,767		B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =			C
amount B minus amount C (if negative, enter "0")			66,767 ▶	66,767	D
Amount transferred on amalgamation or wind-up of subsidiary			224		E
Subtotal (add amounts A, D, and E)			230	691,379	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H		
Other adjustments	246		I		
(add amounts G,H, and I)		x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)				691,379	K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249		
amount K	691,379				
less amount from line 249					
Current year deduction	691,379	x 7.00 % =	250	48,397 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				48,397 ▶	48,397 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	642,982	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		**400**		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		**401**		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402**	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408**	4			
Line 3 minus line 4 (if negative, enter "0")		►		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	**409**	►		9	
Line 6 minus line 9 (if negative, enter "0")				►	O
Line N minus line O (if negative, enter "0")					P
		Line 5	x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
		Amount R	x 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				**410**	

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description		Balance at the beginning of the year $	Transfer on an amalgamation or the wind-up of a subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts	☐	110	115			120
Reserve for undelivered goods and services not rendered	X	130 2,073,612	135	1,860,225	2,073,612	140 1,860,225
Reserve for prepaid rent	☐	150	155			160
Reserve for refundable containers	☐	190	195			200
Reserve for unpaid amounts	☐	210	215			220
Other tax reserves	☐	230	235			240
Totals		270 2,073,612	275	1,860,225	2,073,612	280 1,860,225

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Employee Future Benefits	898,067		2,119,216	898,067	2,119,216
2	Allowance for Doubtful Account	680,000		682,000	680,000	682,000
3	Vested Sick Leave			233,978		233,978
	Reserves from Part 2 of Schedule 13	2,073,612		1,860,225	2,073,612	1,860,225
	Totals	3,651,679		4,895,419	3,651,679	4,895,419

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Brantford Energy Corp	84 Market Square PO Box 308 Brantford ON CA N3T 5N8			174,754		

T2 SCH 14 (99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	255,438	066591			

Note 1: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	255,438	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	255,438	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")		C

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

T2 SCH 15 (06)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2012

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	BRANTFORD POWER INC.	86585 8773 RC0001	1	500,000		
2	BRANTFORD ENERGY CORPORATION	87504 1329 RC0001	1	500,000		
3	BRANTFORD GENERATION INC.	83941 2814 RC0001	1	500,000		
4	BRANTFORD HYDRO INC.	87504 1121 RC0001	1	500,000	100.0000	500,000
5	The Corporation of the City of Brantford	12268 6793 RC0001	4			
				Total	100.0000	500,000 **A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (09)

Canadä

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
		Provide only one number per shareholder				
	100	200	300	350	400	500
1	BRANTFORD ENERGY CORPORATION	87504 1329 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

On: 2012-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☐ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	23,235,420	A
Taxable income for the year (DICs enter "0") *	110	584,343 B			
Income for the credit union deduction * (amount E in Part 3 of Schedule 17) 120					
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * 130					
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * 140					
Subtotal (**add** lines 120, 130, and 140)		C			
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	584,343			
After-tax income (line 150 x general rate factor for the tax year ** 0.72)			190	420,727	D
Eligible dividends received in the tax year	200				
Dividends deductible under section 113 received in the tax year	210				
Subtotal (**add** lines 200 and 210)					E
GRIP addition:					
Becoming a CCPC (line PP from Part 4)	220				
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230				
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240				
Subtotal (**add** lines 220, 230, and 240)			290		F
Subtotal (**add** lines A, D, E, and F)				23,656,147	G
Eligible dividends paid in the previous tax year	300				
Excessive eligible dividend designations made in the previous tax year	310				
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.					
Subtotal (line 300 **minus** line 310)					H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			490	23,656,147	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560		
GRIP at the end of the tax year (line 490 **minus** line 560)			590	23,656,147	

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2011-12-31

Taxable income before specified future tax consequences from the current tax year			J1
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)			N1
Subtotal (line J1 **minus** line N1) (if negative, enter "0")			O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.72) . . . . **500** ______

Second previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year 3,153,970 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) 3,694 M2

Subtotal (**add** lines K2, L2, and M2) 3,694 ▶ 3,694 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 3,150,276 ▶ 3,150,276 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.72) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year . . . 4,562,815 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) 2,463 M3

Subtotal (**add** lines K3, L3, and M3) 2,463 ► 2,463 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 4,560,352 ► 4,560,352 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.72) . . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ► ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ________ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ________ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ________

Net capital losses . . . . ________

Farm losses . . . . ________

Restricted farm losses . . . . ________

Limited partnership losses . . . . ________

Subtotal ________ ► ________ HH

Subtotal (**add** lines FF, GG, and HH) ________ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ________ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ________ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ________ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ________ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ________ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ________ ► ________ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ________ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 366	. . . . =		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 366	. . . . =		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 366	. . . . =		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	366 / 366	. . . . =	0.72000	TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.72000 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

	Line	Amount	Line	Amount	
Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		750,000			
Total taxable dividends paid in the tax year	100	750,000			
Total eligible dividends paid in the tax year			150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	23,656,147	B
Excessive eligible dividend designation (line 150 **minus** line 160)					C
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			180		D
Subtotal (amount C **minus** amount D)					E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)			190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

	Line	Amount	Line	Amount	
Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)					G
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			280		H
Subtotal (amount G **minus** amount H)					I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)			290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

$\frac{\text{Number of days in the tax year before July 1, 2011}}{\text{Number of days in the tax year}}$ ___ / 366 x 12.00 % = ___ % A1

$\frac{\text{Number of days in the tax year after June 30, 2011}}{\text{Number of days in the tax year}}$ 366 / 366 x 11.50 % = 11.50000 % A2

Ontario basic rate of tax for the year (rate A1 **plus** A2) 11.50000 ► 11.50000 % A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 584,343 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1) . . . . 67,199 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	587,043	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)		3
Enter the least of amounts 1, 2, and 3		D

Ontario domestic factor: $\frac{\text{Ontario taxable income *}}{\text{Taxable income earned in all provinces and territories **}}$ = $\frac{584,343.00}{584,343}$ = 1.00000 E

Amount D x factor E		a
Ontario taxable income (amount B from Part 2)	584,343	b

Ontario small business income (lesser of amount a and amount b) ____ F

$\frac{\text{Number of days in the tax year before July 1, 2011}}{\text{Number of days in the tax year}}$ $\frac{}{366}$ x 7.50 % = % G1

$\frac{\text{Number of days in the tax year after June 30, 2011}}{\text{Number of days in the tax year}}$ $\frac{366}{366}$ x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3) ____ H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3) ____ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		J		
Deduct:				
Ontario adjusted small business income (amount I from Part 4)		K		
Subtotal (amount J **minus** amount K) (if negative, enter "0")		L		
OSBD rate for the year (rate G3 from Part 3)	7.00000 %			
Amount L **multiplied** by the OSBD rate for the year				M
Ontario domestic factor (factor E from Part 3)			1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by factor N)				O

Enter amount O on line 410 of Schedule 5.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
BRANTFORD POWER INC.	86585 8773 RC0001	2012-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
BRIAN D'AMBOISE	(519) 751-3522

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 650,000

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$ \; 400{,}000}{\$ \; 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; \$ \; 400{,}000}{\$ \; 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	**B** Name of qualifying co-operative education program **405**
1.	Connestoga College	Powerline Technician
2.	Georgian College	Electrical Engineering Technology
3.		

	C Name of student **410**	**D** Start date of WP (see note 1 below) **430**	**E** End date of WP (see note 2 below) **435**
1.	Robilliard Devan	2012-04-03	2012-08-24
2.	Brandon Thomson	2012-04-03	2012-08-31
3.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	13,455	25.000 %		20
2.		10.000 %	10,395	25.000 %		21
3.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,364	3,000	3,000		3,000
2.	2,599	3,000	2,599		2,599
3.					

Ontario co-operative education tax credit (total of amounts in column K) **500** 5,599 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... ______ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Corporate Taxpayer Summary

Corporate information

Corporation's name: BRANTFORD POWER INC.

Taxation Year: 2012-01-01 to 2012-12-31

Jurisdiction: Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated: Y

Corporation is related: Y

Number of associated corporations: 4

Type of corporation: Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial*: -363,689

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		587,043
Taxable income		584,343
Donations		1,250
Calculation of income from an active business carried on in Canada		587,043
Dividends paid		750,000
Dividends paid – Regular	750,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		23,235,420
Balance of the general rate income pool at the end of the year		23,656,147
Part I tax (base amount)		222,050

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	87,651	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	512,940
Investment tax credits		Other*		Surtax credit	
Abatement/Other*	134,399	Provincial or territorial tax	61,600	Other*	

Balance due/refund (–) -363,689

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Unused surtax credit (Schedule 37)	60,412
Capital dividend amount	10,676
Cumulative eligible capital	642,982
Financial statement reserve	4,895,419
Other reserves	1,860,225

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	587,043		
Taxable income	584,343		
% Allocation	100.00		
Attributed taxable income	584,343		
Tax payable before deduction*	67,199		
Deductions and credits			
Net tax payable	67,199		
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	67,199		
Instalments and refundable credits	5,599		
Balance due/Refund (-)	61,600		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
BRANTFORD POWER INC.	78,145,607	78,145,607	83,638,344	83,638,344
BRANTFORD ENERGY CORPORATION				
BRANTFORD GENERATION INC.				
BRANTFORD HYDRO INC.				
The Corporation of the City of Brantford				
Total	78,145,607	78,145,607	83,638,344	83,638,344

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)
Total		

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	2012-12-31	2011-12-31	2010-12-31	2009-12-31	2008-12-31
Net income	587,043	-346,823	3,162,683	4,562,815	8,140,016
Taxable income	584,343		3,155,608	4,562,815	8,140,016
Active business income	587,043		3,158,989	4,560,352	8,137,553
Dividends paid	750,000	1,450,000	750,000	750,000	500,000
Dividends paid – Regular	750,000	1,450,000	750,000		
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	23,235,420	23,482,781	21,307,960	18,206,921	12,673,385
GRIP – end of the year	23,656,147	23,237,144	23,482,781	21,307,960	18,206,921
Donations	1,250	1,450	7,075		
Balance due/refund (-)	-363,689	-1,025,877	-608,058	-1,228,548	

Federal taxes

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Part I before surtax	87,651		568,625	867,320	1,587,676
Surtax					
Part I.3					
Part IV					
Part I & Surtax	87,651		568,625	867,320	1,587,676
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit					
Abatement/other*	134,399		630,752	866,714	1,505,694

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
ITC refund					
Dividend refund			985	657	657
Instalments	512,940	1,025,877	1,632,950	2,860,841	1,587,019
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2012-12-31	2011-12-31	2010-12-31	2009-12-31	2008-12-31
Net income	587,043	-346,823	3,162,683		8,140,016
Taxable income	584,343		3,155,608		8,140,016
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income	584,343		3,155,608		8,140,016
Surtax			39,979	42,500	42,500
Income tax payable before deduction	67,199		409,970	638,794	1,139,602
Income tax deductions /credits			39,979	42,500	42,500
Net income tax payable	67,199		409,970	638,794	1,139,602
Taxable capital			76,030,482	69,056,614	73,107,253
Capital tax payable			47,282	126,836	133,563
Total tax payable*	67,199		457,252	765,630	1,273,165
Instalments and refundable credits	5,599				2,059,472
Balance due/refund**	61,600		457,252	765,630	-786,307

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

ATTACHMENT L

REFERENCE: 4.0 SEC-11

December 15, 2011

Dear [name of employee],

We would like to take this opportunity to inform you that due to a corporate reorganization, effective March 1, 2012, your employment with the City of Brantford will end and will be transferred to Brantford Power Inc. The decision has been triggered to ensure compliance with Ontario Energy Board regulations and to more effectively align our operations.

Please be assured that this decision will have minimal impact on your employment. BPI will recognize your seniority date with the City, and BPI will continue to apply the terms of the collective agreement. As such, the terms and conditions of your employment will not change when BPI becomes your employer.

We are very excited by this development and feel that it is very positive for everyone. However, we recognize that you may have questions. Please join us at a meeting for a more detailed discussion of the reorganization where we will be happy to address any questions you may have.

Time:	January 10, 2012
	3:00 p.m.
Location	Human Resources Training Room
	Market Square

We look forward to seeing you there.

Yours truly,

Ted Salisbury	George Mychailenko
CAO, City of Brantford	CEO, Brantford Power Inc.
CEO, Brantford Energy Corp.	Brantford Power Inc.

December 15, 2011

Dear [name of employee],

We would like to take this opportunity to inform you that due to a corporate reorganization, effective March 1, 2012, your employment with the City of Brantford will end and will be transferred to Brantford Power Inc. The decision has been triggered to ensure compliance with Ontario Energy Board regulations and to more effectively align our operations.

Please be assured that this decision will have minimal impact on your employment. Brantford Power will recognize your date of hire with the City, and the terms and conditions of your employment will not change.

Note that the Association of Professional and Administrative Employees (APAE) will not automatically continue to represent you when Brantford Power becomes your employer. You may wish to discuss this with the Association to decide whether to continue your membership.

We are very excited by this development and feel that it is very positive for everyone. However, we recognize that you may have questions. Please join us at a meeting for a more detailed discussion of the reorganization where we will be happy to address any questions you may have.

Time:	January 10, 2012
	3:00 p.m.
Location	Human Resources Training Room
	Market Square

We look forward to seeing you there.

Yours truly,

Ted Salisbury
CAO, City of Brantford
CEO, Brantford Energy Corp.

George Mychailenko
CEO, Brantford Power Inc.
Brantford Power Inc.

Date

Name
c/o Department, Brantford Power Inc.

<u>RE: Transfer to Brantford Power Inc.</u>

This will confirm that you will continue in your current full-time position of Title effective on April 1, 2012 with Brantford Power Inc. (BPI). You will continue to report to Spvr Name, Spvr Title.

BPI will recognize your date of hire with the City of Brantford which was Date.

Your salary will continue to be Level Number , Step Number of the City Exempt Staff wage grid which is $Amount per annum pending job evaluation/salary compensation review and adjusted thereafter as approved by the Board. You will work a thirty-five (35) hour work week, Monday to Friday, 8:00 a.m. to 4:00 p.m., with a one hour unpaid lunch break.

Your employee group benefits will be in accordance with the current schedule of benefits applicable to “non-union exempt full-time staff” employed by the City of Brantford. You will continue to participate in the OMERS pension plan. Your vacation entitlement will be Amount (Number) days per annum. Should you have any questions regarding your benefits, please contact the City of Brantford Human Resources Department.

All other conditions of employment are subject to the Employment Standards Act, Corporate and Departmental Policies & Procedures (which may be altered by management from time to time), and any other relevant piece of Legislation and/or Act.

Thank you for your cooperation during this transition and best wishes for continued success in your employment with Brantford Power Inc.

George Mychailenko
CEO, Brantford Power Inc.

cc:
Tabitha Fischer, Human Resources Department, ext. 2362

MEMORANDUM OF AGREEMENT

BETWEEN:

THE CANADIAN UNION OF PUBLIC EMPLOYEES, LOCAL 181 ("CUPE")

- and -

BRANTFORD POWER INC. ("BPI"),

WHEREAS the Corporation of the City of Brantford (the "City") and CUPE are parties to a collective agreement expiring on March 31, 2012 (the "Collective Agreement"),

AND WHEREAS the City and BPI have given notice to CUPE that in order for BPI to comply with various Ontario Energy Board regulatory requirements, certain assets and business functions will be transferred from the City to BPI effective April 1, 2012 (the "Transfer");

AND WHEREAS the employees within CUPE's bargaining unit whose functions are to be transferred to BPI have been provided with written notice of the Transfer (the "Transferring Employees");

AND WHEREAS CUPE and BPI are desirous of resolving the issues arising out of the Transfer on a full and final basis,

NOW THEREFORE IT IS AGREED:

1. BPI and CUPE agree that the Transfer, as contemplated, constitutes a "sale" of part of the City's business to BPI pursuant to s. 69 of the *Labour Relations Act, 1995* (the "*Act*").

2. BPI and CUPE agree that conditional on the Transfer occurring as contemplated, effective as of the date of the Transfer:

a. BPI shall be bound by the Collective Agreement as a successor employer pursuant to s. 69 of the *Act*;

b. the Transferring Employees shall be automatically transferred to and become employees of BPI as of the date of the Transfer;

c. the Transferring Employees shall continue to be represented by CUPE when they become employees of BPI, and their seniority date shall be the seniority date that they had with the City; and

d. the Transferring Employees shall be employed with BPI subject to the Collective Agreement between CUPE and BPI referred to in para. (a).

3. As the Collective Agreement will expire as of the date of the Transfer, BPI confirms that conditional on the Transfer occurring as contemplated, CUPE may serve on BPI notice to bargain pursuant to s. 59 of the *Act* at any time after the Transfer.

4. The parties agree that conditional on the Transfer occurring as contemplated, effective as of the date of the Transfer this Memorandum of Agreement shall become a Letter of Understanding pursuant to the Collective Agreement between CUPE and BPI.

5. This Memorandum of Agreement is, and continues to be, conditional on the Transfer occurring on April 1, 2012 substantially on the terms disclosed to CUPE by the City and BPI. Should the Transfer not occur as contemplated, this Memorandum of Agreement shall be void, and shall not be relied on or referred to by either party in any future proceedings.

DATED THIS 8th DAY OF MARCH, 2012.

THE CANADIAN UNION OF PUBLIC EMPLOYEES, LOCAL 181

____

BRANTFORD POWER INCORPORATED

____

ATTACHMENT M

REFERENCE: 4.0 SEC-15

Collective Agreement

Between
Brantford Power Inc.
and
The Canadian Union of Public Employees, Local 181, Brantford Power Unit

April 1, 2012 – March 31, 2014

Contents

THIS AGREEMENT entered into at Brantford, Ontario as of the first day of April 1, **2012**
BY AND BETWEEN:

BRANTFORD POWER INC.
(Hereinafter referred to as the "Employer")

OF THE FIRST PART and

CANADIAN UNION OF PUBLIC EMPLOYEES LOCAL 181
BRANTFORD POWER UNIT
(Hereinafter referred to as the "Union")

OF THE SECOND PART

ARTICLE 1 - GENERAL PURPOSE

1.01 Whereas, in the interests of the efficient conduct and administration of the Employer's affairs, it is desirable that there shall obtain harmonious relations, fair and reasonable remuneration for the services rendered, having regard to the responsibility attached to the position held, the nature of the duties thereof, the manner of their discharge, seniority in the service and security of tenure of office; now therefore witnesseth that the parties hereto covenant and agree as follows:

ARTICLE 2 - RECOGNITION AND COVERAGE

2.01

a) The Employer recognizes the Union as the exclusive bargaining agent for all employees of the Brantford Power Inc. set forth in Schedule "A" **& "B"** attached hereto, save and except **Directors and above, Managers, Senior Foreperson, Forepersons, Supervisors, Administrative Coordinator, Senior Financial Analyst, Senior Regulatory Analyst, Settlement Energy Metering Officer, Regulatory Analyst and those members of the BPPAE as well as those excluded under the Ontario Labour Relations Act and those represented by another trade union.**

b) It is understood that only full-time employees in the classifications in Schedule "A" **& "B"** are included in the bargaining unit. Full-time does not include employees who work twenty-four (24) hours or less per week.

c) The parties agree that:

1. Students will become members of the Union and will pay Union Dues and/or assessments as advised by the Union upon commencement of employment.

2. Students will be hired for their specific work term or vacation period and shall not acquire seniority during their employment.

3. Students, except as otherwise specified, shall be paid in accordance with the schedule of rates attached hereto as Schedule "**B**".

4. The Union recognizes the right of the Employer to assign students such work as may from time to time become available provided that such students shall not be hired to replace regular employees on the seniority list or to substitute for seniority positions when they become vacant except as otherwise provided herein.

5. It is agreed by the parties that students are hired to complement the staff and work generally under the guidance of regular union and/or non-union staff.

6. Employees hired for a specific Government Subsidized Program shall not serve a probationary period and shall not acquire seniority during their employment. The terms and conditions as set forth for each particular program will be detailed in a Letter of Understanding to the President and Unit Chairperson, which will be mutually agreed to by the parties. Employees shall have the right to grieve from the first day of hire under the provisions of the Grievance Procedure as in Article 5 of the Collective Agreement with respect to matters of monetary, disciplinary or dismissal. The participation in benefits will be subject to the terms of the particular Government Subsidized Program and participation will be subject to the conditions of this Collective Agreement. Employees hired under these programs shall not be hired to replace regular employees on the Seniority List.

   Clerical employees hired for a specific Government subsidized program shall be paid no less than the minimum rate of Level "1", Salary Schedule "A".

   The union is to be forwarded copies of the Corporation's application for program funding and terms of reference for the program.

The union will be provided with notification of the names of employees hired under Government Subsidized Programs.

2.02 The term "employee" or "employees", as used in this Agreement, unless it is clearly specified otherwise, shall mean only those employees who are included in the bargaining unit as described above.

2.03 No member of management shall perform the duties of positions performed by employees covered by this Agreement, save and except for a period of no longer than thirty (30) working days in cases of emergency, during periods of instruction, or when employees normally performing the duties are not available.

2.04 No **employee** who has completed five (5) years of service shall be laid off as a result of contracting out of work regularly performed by members of this bargaining unit on the seniority list.

ARTICLE 3 - RELATIONSHIP

3.01 The parties agree that no employee shall, in any manner, be discriminated against or coerced, restrained or influenced. The parties agree to share a commitment to reach beyond the standards set in compliance with those outlined by the Ontario Human Rights Code, **the Occupational Health and Safety Act and the Ontario Labour Relations Act.**

3.02 The Employer agrees that all present employees shall remain, and new employees shall become, members of the Union when they commence employment. **Within one (1) week of commencing employment, the employee's immediate supervisor or designate, shall introduce all new employees to his/her Unit Chairperson. The Unit Chairperson shall be given an opportunity to interview each new employee within regular working hours, without loss of pay, for a maximum of fifteen (15) minutes for the purpose of acquainting the new employee with the benefits and duties of Union membership and his/her responsibilities and obligations to the Union.**

3.03 The Employer agrees to acquaint new employees with the fact that this Agreement is in effect and with the conditions of employment set out in this Article and Article 15. The Employer will supply each employee with a copy of this Agreement. **The Employer and the Union shall each have a signed original copy of this Agreement and an**

additional signed original copy shall be provided to the Ministry of Labour. The Employer shall provide the Recording Officer of the Union with three (3) printed copies of the Agreement.

3.04 Upon request, subject to the approval of the **Director, or designate**, as to time, arrangements will be made with the **Employer's designated Human Resources Representative** for an employee to have access to and review his/her file and shall be permitted to respond in writing to any document contained therein. Such response shall become part of the personnel file. An employee may photocopy any material contained in his/her personnel file. Such review will be held in the presence of the **Employer's designated Human Resources Representative** and such request shall not be unreasonably withheld. The presence of such a response in the employee's file shall not be construed as being an acceptance by the employer of the statements contained therein either as to fact or opinion.

ARTICLE 4 - RESERVATION OF MANAGEMENT FUNCTIONS

4.01 The Union acknowledges that it is exclusively the function of the Employer to:

a) Maintain order, discipline and efficiency;

b) Hire, discharge, direct, transfer, promote, demote, lay-off and suspend, or otherwise discipline employees, providing that a claim of discriminatory promotion or demotion or a claim that an employee has been discharged or disciplined without just cause, may be subject to a grievance and dealt with in accordance with the grievance procedure;

c) Make and alter, from time to time, rules and regulations to be observed by the employees, provided they are not inconsistent with the provisions of this Agreement.

d) Generally to manage the office and to direct the work of the employees and, without restricting the generality of the foregoing, to determine the number of personnel required and the methods, procedures and equipment to be used and all other matters concerning the Employer's operations not otherwise specifically dealt with elsewhere in this Agreement; and

e) Where a decision is made by the Employer affecting a group of employees, the Unit Chairperson, or designate, and the CUPE National Servicing Representative shall be notified by the **Employer's designated Human Resources Representative** as soon as it is practicable but in any event not later than thirty (30) days prior to the decision being implemented or such time limits as specifically contained in this Agreement.

f) Where changes in the working personnel are implemented, i.e., hiring, lay-offs, re-calls, terminations, transfers, and redundant positions and such other notification as contained in this Agreement, the **Employer's designated Human Resources Representative** shall notify the Unit Chairperson, or designate, as soon as it is practicable but in any event not later than three (3) working days. Such notification may be made by way of personal service or registered mail post-marked within the three (3) day period as aforesaid.

g) When requests are made to the Employer by an employee in accordance with the Agreement or where transfers are made of a temporary nature within the terms of this Agreement (no longer than six (6) months' duration), such notification or request shall pass between the Employer and employee.

4.02 The Employer agrees that these functions shall be exercised in a manner consistent with the provisions of this Agreement.

4.03

a) When it is necessary to reprimand an employee, the employee shall be advised of the option for union representation and the reprimand shall be made in private. Where such reprimand may result in demotion, suspension, or dismissal of an employee, a Union Representative shall accompany the employee being reprimanded. **There may be in attendance another management representative.**

b) In the event that an employee has been reprimanded as outlined in 4.03 (a), such employee shall be provided, in writing, the particulars which caused the reprimand and the Unit Chairperson shall receive a copy.

c) Such reprimand shall remain on an employee's record for a period of eighteen (18) months.

ARTICLE 5 - GRIEVANCE PROCEDURE

5.01 In order to provide an orderly procedure for the servicing of differences between the parties and the employees' grievances which may arise hereunder, the Union may establish a Unit Grievance Committee, not more than three (3) of whom may attend meetings with the Representatives of the Employer, and the Unit Chairperson shall notify the **Employer's designated Human Resources Representative** in writing, of the names of the members of the Unit Grievance Committee and any change thereto before the Employer shall be required to recognize them. Only two (2) duly authorized members of the Unit Grievance Committee, together with the Department Steward concerned constituting the three (3) members shall assist employees or attend meetings as provided in the Grievance Procedure.

5.02

a) It is understood that members of the Grievance Committee and other recognized Committees have their regular work to perform on behalf of the Employer and that if it is necessary to service a grievance or perform other Union functions connected with the Agreement during working hours, they will not leave their work without first obtaining the permission of the **Director, or designate**, which permission will not be unreasonably withheld. When resuming their regular work they will report to the **Director, or designate** and, if required, will give a reasonable explanation as to their absence.

b) It is understood that permission requested of a Director as it appears in any articles of the Agreement, should the Director not be available, the request shall be made to the next member of Management available in the Department.

5.03 The Union may have the services of a representative of the Canadian Union of Public Employees to assist in the hearing of grievances, as provided under the terms of this Agreement, **and at mediation** and arbitration and at negotiations.

5.04 When an employee has a complaint arising out of the interpretation, application, administration or alleged violation of the terms of this Agreement, he/she shall present his/her complaint to his/her **Manager or designate** no later than fifteen (15) working days following the date upon which he/she should have become aware of the circumstances which led up to the complaint. In the case of a complaint, requesting a monetary settlement, the limitation shall be extended to one (1) calendar year. The **Manager or designate** shall have three (3) working days to verbally reply to the complaint. Failing satisfaction, the grievance may be dealt with in the following manner and sequence:

STEP 1

The employee in the presence of his/her Union Steward, shall present his/her alleged grievance in writing signed by the employee involved, to his/her **Director** or Designate within seven (7) working days after receiving the verbal reply to the complaint. The **Director** or Designate shall render his/her decision to the grievor with a copy to the Union Steward in writing within three (3) working days.

STEP 2

Failing settlement under Step 1 of the Grievance Procedure, the Unit Grievance Committee may submit the grievance in writing to the **CEO** within five (5) working days of receiving the decision in Step 1. The **CEO** shall grant the Union Grievance Committee a hearing within ten (10) working days. The **CEO** shall render the Employer's decision in writing within five (5) working days to the Unit Grievance Committee with a copy to the Grievor. It is understood that the **CEO** may have the assistance of any other management representatives.

5.05 Failing settlement under Step 2 of any differences between the parties arising from the interpretation, application, administration or alleged violation of this Agreement, including any questions as to whether a matter is arbitrable, such difference may be taken to arbitration as provided in Article 6 herein, and if no written notification is received within forty (40) calendar days after the decision in Step 2 is given, it shall be deemed to have been abandoned.

5.06 Any complaint or grievance concerning or affecting a group of employees shall be originated under Step 2.

5.07 The time limits provided under the Grievance Procedure may be extended, **in writing,** by mutual agreement of the parties.

5.08 A Policy Grievance Procedure is hereby recognized whereby either party to this Agreement may submit any matter in dispute to grievance beginning at Step 2 of the Grievance Procedure. However, such grievance shall not include matters upon which employee(s) are personally entitled to grieve.

5.09 **Discipline:** A claim by any employee who has completed his/her probationary period that he/she has been unjustly discharged or suspended for three (3) working days or more shall be treated as a grievance if a written statement of such grievance is received and date stamped within (5) working days after the discharge or suspension is effected. Such special grievance may be settled under the Grievance**, Mediation** or Arbitration Procedures by:

a) Confirming the Employer's action in dismissing or suspending the employee;

b) Re-instating the employee with full compensation for the time lost; or

c) By any other arrangement which may be deemed just and equitable.

5.10 All decisions arrived at between the representatives of the Employer and the Union shall be final and binding upon the Employer, the Union and the employee or employees concerned.

5.11 It is agreed that an appeal by an employee to an elected or appointed non-staff official of the City Council **or Shareholder or Board of Directors** over a matter that is being or could be grieved under the terms of this Agreement, or could be the subject of an appeal under Article 10 of the Job Evaluation Plan shall constitute a breach of this Agreement. Violation of this clause shall render an employee liable to disciplinary action up to and including dismissal.

5.12 It is understood that the Union may have the services of the local Union Chief Steward without loss of pay to assist in the hearing of grievances at Step 2 and thereafter of the Grievance Procedure.

5.13 **MEDIATION**

Unresolved grievances may be referred to mediation upon mutual agreement of the parties. Such request for referral shall be made by the requesting party within five (5) working days after the disposition of Step 2 and a response from the responding party shall be issued to the requesting party within five (5) working days. The mediator shall be selected by mutual agreement of the parties and costs shall be shared equally. The mediator shall endeavour to assist the parties to settle the grievance by mediation.

In cases where the responding party declines mediation, the timelines to file the matter for arbitration shall commence upon the date the requesting party receives the written response of denial from the responding party. In cases where the matter is placed before a mediator but is not resolved to the satisfaction of the parties, the timelines to file for arbitration shall commence upon completion of the mediation stage.

ARTICLE 6 – ARBITRATION

6.01 When a dispute arises in respect of any of the matters covered by this Agreement, including;

(a) the interpretation, application or administration of this Agreement, or

(b) when an allegation is made that this Agreement has been violated,

and if a satisfactory settlement cannot be reached through the process provided for under Article 5, the matter in dispute may be submitted by the Corporation or the Union to Arbitration.

6.02 **SINGLE ARBITRATOR**: Either of the parties to this Agreement may notify the other party in writing of its desire to submit the matter in dispute to a single arbitrator. If the recipient of the notice and the party desiring the arbitration do not, within a period of ten (10) working days after the receipt of the said notice agree upon a single arbitrator the appointment of a single arbitrator shall be made by the Minister of Labour for the Province of Ontario upon the request of either party.

6.03 **BOARD OF ARBITRATION:** Either of the parties to this Agreement desirous of exercising this provision shall notify the other party in writing, and at the same time nominate a representative. Within five (5) working days thereafter the other party shall nominate a representative. The two representatives so nominated shall attempt to select by agreement a Chairperson of the Arbitration Board. If they are unable to agree upon such a Chairperson within a period of five (5) days following the date of their appointment either representative will then request the Minister of Labour for the Province of Ontario to appoint a Chairperson.

6.04 Any Single Arbitrator/Arbitration Board appointed pursuant to this Article has no jurisdiction to alter, modify or amend the collective agreement or make any decision that is inconsistent with the provisions of this Agreement.

6.05 The decision of the Single Arbitrator/Arbitration Board appointed pursuant to this Article is final and binding upon the Corporation, the Union and any Employee affected thereby.

6.06 Where there is a single Arbitrator, the Corporation and the Union shall share equally the cost of the arbitration proceedings and the Arbitrator. Where there is a Board of Arbitration, each party shall bear the cost of its own nominee and shall share the cost of the Chairperson and the arbitration proceedings.

6.07 Notwithstanding the provisions of Article 5 or this Article;

(a) no matter in dispute may be submitted to arbitration which has not been properly processed through the grievance procedure as set forth in Article 5,

(b) the provisions of this section shall not be considered to have been waived unless agreed upon, in writing, by both parties.

6.08 No person may be appointed to the Board of Arbitration who has been involved in an attempt to negotiate or settle the grievance.

6.09 Upon mutual consent of the parties any difference may be submitted to a three person Board of Arbitration.

ARTICLE 7 - NO STRIKE AND NO LOCKOUT

7.01 In view of the orderly procedure for settling grievances, following the signing of this Agreement, the Employer agrees that it will not cause or direct any lockout of its employees and the Union agrees that there will be no strike or other collective action which will stop, curtail or interfere with work or the Employer's operations during the life of this Agreement.

The Union agrees that if any such collective action takes place, it will repudiate it forthwith and require its members to return to work. Any employee participating in any such strike will be subject to discipline, including discharge.

7.02 In the event that any employee, other than those covered by this Agreement, engages in a strike or where employees in a labour dispute engage in a strike and maintain picket lines, the employees covered by this Agreement shall have the right to cross or to refuse to cross such picket lines.

ARTICLE 8 - SENIORITY, PROMOTIONS, STAFF CHANGES

8.01

a) Seniority List: Seniority is preference or priority measured by length of service. The Employer shall maintain a seniority list showing the date upon which each employee's service commenced. An up to date seniority list shall be placed on the bulletin board of each Department by the 15th of January and July of each year. Copies shall be sent to the Unit Chairperson and the Secretary of the Union.

b) Seniority for New Employees: Newly hired employees shall be considered on a trial basis for a period of **ninety (90)** worked days within a **six (6)** month period, or such other extended period of time as may be mutually agreed upon, and after satisfactory completion of such trial period, seniority shall be effective from the original date of employment.

c) Seniority During Absence: If an employee is absent from work because of sickness, accident, lay off or leave of absence approved by the Employer, he/she shall not lose seniority rights. An employee shall lose his/her seniority in the event:

    (1) He/she is discharged for just cause and is not re-instated.

    (2) He/she resigns.

    (3) He/she is absent from work in excess of three (3) working days without notifying the **Director**, or designate, unless such notice was not reasonably possible.

(4) He/she fails to report for work within ten (10) days after being notified by registered mail to return to work following a lay off or fails to notify the **Director**, or designate by registered mail postmarked within five (5) days after receipt of such notice of his/her intention to report for work.

(5) He/she is laid off for a period of longer than twelve (12) consecutive months.

(6) He/she fails to return to work upon termination of an authorized leave of absence without reasonable proof for the cause of delay.

d) The Employer agrees to supply the Union with the list of the names, phone numbers and addresses **and positions** of the present and new Employees of the bargaining unit on the 15th of **June** each year. The union will save the Employer harmless from any and all claims that may be made against the Employer for disclosing such information.

8.02

a) When **an employee accepts a position, a transfer, a promotion** (excluding promotions to positions outside of the Bargaining Unit which shall not be subject to the terms of this Agreement), **is laid-off or recalled**, seniority shall apply when the employee has the **basic** qualifications, as outlined in the approved Job Description, to perform the work available.

b) An employee who **accepts a position** shall be allowed a period of thirty (30) working days to prove his/her ability for the position. If the Employer or the employee finds he/she is unable to perform the duties of the position during such period, the employee shall revert to his/her former classification and position.

c) An employee who **accepts** a position with the Employer, not subject to the provisions of this Agreement, shall be allowed a period of thirty (30) working days to prove his/her ability for the position. Failing to qualify for such position, the said employee shall revert to his/her former classification and position within the Bargaining Unit.

d) It is understood that other employees who have **accepted a position** as a result of the changes as outlined in 8.02 (b) or 8.02 (c) will be required to revert to their former positions and classifications, due to the reverse situation.

e) When **accepting** a position not subject to the provisions of this Agreement, an employee, provided he/she does not break his/her service with the Employer, shall retain his/her seniority for one year only from the date of **acceptance**. It is understood that such employee shall not continue to accumulate seniority during the said one-year period.

f) **Redundancy**: Employees occupying positions which have become redundant may exercise their seniority rights by displacing other employees with less seniority in classifications at the same or at a lower level, provided the employee has the **basic** qualifications, (as outlined in the Job Description) to perform the duties in the classification.

i.) If the employee occupying the redundant position displaces another employee at the same level then the bumping employee shall continue to receive their current rate of pay at the time.

ii.) If the employee occupying the redundant position displaces another employee at one level lower than themselves, then the bumping employee shall maintain their current rate of pay at the time of bumping for a period of one (1) year after which time they would become "red circled" and subject to Article 10.06 (c).

iii.) If the employee occupying the redundant position displaces an employee at two (2) levels below themselves, then the employee shall maintain their current rate of pay at the time of bumping for a period of six (6) months after which time they would become "red circled" and subject to Article 10.06 (c).

iv.) If the employee occupying the redundant position displaces an employee more than two (2) levels below themselves, then the employee would become "red circled" and subject to Article 10.06 (c).

Lay Offs:

g) A lay-off shall be defined as a reduction in the work force or a reduction in the standard hours of work as defined in this agreement of more than forty-eight (48) hours duration, due to lack of work.

h) In the event of a lay-off, employees may exercise their seniority rights by displacing other employees with less seniority in classifications at the same or at a lower level, provided the employee has the **basic** qualifications, (as outlined in the Job Description) to perform the duties of the classification.

i.) If the employee occupying the laid-off position displaces another employee at the same level then the bumping employee shall continue to receive their current rate of pay at the time.

ii.) If the employee occupying the laid-off position displaces another employee at one level lower than themselves, then the bumping employee shall maintain their current rate of pay at the time of bumping for a period of one (1) year after which time they would become "red circled" and subject to Article 10.06 (c).

iii.) If the employee occupying the laid-off position displaces an employee at two (2) levels below themselves, then the employee shall maintain their current rate of pay at the time of bumping for a period of six (6) months after which time they would become "red circled" and subject to Article 10.06 (c).

iv.) If the employee occupying the laid-off position displaces an employee more than two (2) levels below themselves, then the employee would become "red circled" and subject to Article 10.06 (c).

i) Employees shall be recalled in the order of their seniority.

j) New employees shall not be hired until those laid off have been given an opportunity of recall in accordance with article 8.0l (c) (4).

k) Unless legislation is more favourable, the Employer shall notify the employee(s) who are to be laid off five (5) working days prior to the effective date of the **lay-off, except in the event of any extraordinary or unforeseen circumstance.**

l) If the employee has not had the opportunity to work the days provided in this article, he/she shall be paid for the days for which work was not made available.

m) Grievances concerning lay-offs and recalls shall be initiated at Step 2 of the Grievance Procedure **within fifteen (15) days of the notice of layoff or recall.**

n) **Employees have a right to return to their home position for a period of (12) twelve months, if bumped or laid off from their home position.**

8.03 **VACANCIES**:

a) Notices of all vacancies or new positions and non-union positions (which shall include the nature of the position, the required knowledge and education, ability and skills and salary level) shall be posted on the bulletin boards of each Department **and the Employer's Employee Forum** for a period of five (5) working days and a copy thereof shall be sent to the Unit Chairperson of the Union before being filled. Eligible employees shall have an opportunity to apply and **will not be unreasonably denied an** interview. Following the selection of and notification to the successful applicant, all other applicants shall be advised of the Employer's decision within three (3) working days of the appointment being made.

b) It is understood that any employee who is accepted for a posted position may be precluded from applying for another job opening at the same salary level for a period of twelve (12) months. This Article does not apply to an employee who is accepted for a posted temporary position.

c) **It is agreed that those employees transferred to another classification, excluding those employees demoted under the terms of this Agreement, shall be paid no less than the rate they are presently receiving. An employee shall receive the higher of his/her own rate or the rate for the job to which he/she is assigned in excess of one (1) shift.**

These provisions shall not include relief during annual paid vacations.

8.04 **TEMPORARY VACANCIES**

Vacancies created as a result of an employee being absent from work may be posted and filled when it is reasonable to expect that the vacancy may extend beyond twelve (12) weeks.

The Employer may post and fill a temporary position for a period of up to thirty (30) months. The initial and secondary vacancy shall be posted internally, in accordance with article 8.03 (a), and any subsequent ensuing vacancy may be posted and/or filled at the discretion of the Employer.

Upon return of the absent employee, the employee(s) filling the temporary vacancy(s) shall be returned to their former position(s).

ARTICLE 9 - HOURS OF WORK

9.01

i.) The standard work week shall be composed of thirty-three (33) hours and forty-five (45) minutes, consisting of five (5) days of six (6) hours and forty-five (45) minutes each, Monday to Friday, provided however, it is agreed that the standard work week for the Electrical Construction Inspectors shall be thirty-five(35) hours per week.

ii.) The standard hours of work for students shall be the same hours of work as the department in which they work, effective April 1, 2012.

9.02 It is expressly understood that the provisions of this Article are intended only to provide a basis for calculating time worked and shall not be, or be construed to be, a guarantee as to the hours of work per day or as to the hours of work per week.

9.03 The standard hours of work for thirty-three and three-quarter (33-3/4) hour workers shall be from 8:30 a.m. to 4:30 p.m., with one and one-quarter (1-1/4) hours allowed for lunch period. These hours may be amended for certain positions or circumstances with the mutual agreement of the parties.
The standard hours of work for Electrical Construction Inspectors shall be from 8:30 a.m. to 4:30 p.m., with sixty (60) minutes allowed for an unpaid lunch period.

The lunch period and the rest period shall be taken at a time suitable to the operation of each Department as arranged by the immediate supervisor.

For the efficiency of the operation, the standard starting and quitting times may be changed by mutual agreement of the parties.

Those employees who are members of this Unit who are working at locations other than 84 Market Street will adopt hours as in their work location.

9.04 **Employees** shall be allowed a fifteen (15) minute rest period in the first half and the second half of each shift. The fifteen (15) minute rest period should be taken at the job location except when conditions warrant. The period off the job shall not exceed fifteen (15) minutes.

ARTICLE 10 - SCHEDULE OF WAGES, OVERTIME RATES AND JOB EVALUATION

10.01

Schedule of Wages:

a) The Employer agrees to pay and the Union agrees to accept, for the term of this Agreement, the **wage** schedule attached hereto as Schedule "A".

b) Employees will be paid by direct deposit on a weekly basis with pays calculated based on an hourly rate unless mutually agreed otherwise by the parties. **At such time the Corporation implements a bi-weekly pay period, the Union will be provided no less than three (3) months' notice of such change.**

c) The Employer agrees to grant equal pay to all members of the Union for equal work, regardless of the gender of the employee concerned.

Overtime Rates:

d) Authorized work performed in excess of the employee's standard work week or standard work day will be paid at the rate of time and one-half his/her regular hourly rate, provided that overtime premium payment shall not pyramid. The employee shall be permitted to indicate his/her preference for payment, either at the rate of time and one-half (I ½) his/her regular rate of pay, or for time and one-half lieu time off. However, should such employee request that he/she be reimbursed for overtime with time and one-half lieu time off, this would only be permitted provided that such lieu time off is taken at a mutually agreed upon time. The lieu-time bank can accumulate to an annual maximum of **twenty (20)** days and can be carried over from year to year however at no time can the bank exceed ten (10) days.

e) Authorized overtime work performed on a Sunday shall be paid at the rate of double the employee's regular hourly rate.

f) Authorized work performed on a paid holiday, defined in Article 11 except Christmas or New Year's Day, shall be paid at the rate of time and one-half the employee's regular hourly rate in addition to any holiday pay to which he/she may be entitled.

g) Authorized work performed on Christmas or New Year's Day shall be paid at the rate of double the employee's regular hourly rate. Should the employee work four (4) hours or more, he/she shall also be entitled to a lieu day off or pay therefor at his/her regular hourly rate. Should the employee work less than four (4) hours, he/she shall be entitled to lieu time off or pay therefor on a time for time basis at his/her regular hourly rate. It is understood that lieu time off, as contained in this article, will be taken at a mutually agreed upon time.

h) An employee called in to work outside of his/her normal shift shall be paid two (2) hours pay at straight time for reporting plus time and one-half the rate for hours worked.

i) **Meal Allowance:**

Any employee who is required and authorized to work a minimum of two (2) hours overtime shall be entitled to a seven dollar ($7.00) meal allowance provided that not more than one (1) hour has elapsed between his/her regular stopping time and his/her return to work. Effective April 1, 2013 meal allowance increased to eight ($8.00).

Job Evaluation

10.02 The evaluation of jobs shall continue to be made in accordance with the Job Evaluation Manual, as revised by the parties, herein referred to as the "Manual", which includes the Point Evaluation method and such other techniques as included therein. A copy of the Job Evaluation Manual shall be supplied to the members of the Job Evaluation Committee and the Unit Chairperson.

10.03 The duties of the Committee, the procedure for job evaluation and the procedure for an appeal from a decision of the Committee, shall be as established in the Manual.

10.04 The method of job evaluation adopted in Article 10.02 may be amended from time to time, in whole or in part, upon the unanimous recommendations of the committee and the agreement of the parties to this Agreement.

10.05 The job classification of employees, as evaluated pursuant to the Manual mentioned in Article 10.02 or other agreed upon methods as of the signing of this Agreement or in the future, shall be included within the appropriate salary level set out in Schedule "A" in accordance with their evaluated positions.

10.06 Individual existing wage rates in excess of the rate established by the Job Evaluation shall be known as "red circle" rates.

a) Employees, who are receiving wages based on rates in excess of the rate assigned to their job classification at the time of the signing of this Agreement, shall continue to receive a wage which is no less than the wage they received prior to the signing of this Agreement, which rate shall be considered to be "red circled".

b) It is understood that rates considered to be "red circle" rates within the meaning of Article 10.06 and 10.06(a) herein, shall not be deemed to be within the wage schedule established by this Agreement, except where specific provision is made on their behalf elsewhere in this Agreement in respect of a negotiated increase. An employee whose rate has been "red circled" shall continue to receive no less than the "red circle" rates so long as he/she continues within the classification for which the rate was established.

c) It is understood that a "red circle" rated employee, as mentioned in Article 10.06, 10.06(a) and 10.06(b), shall receive fifty percent (50%) of all negotiated increases for his/her classification during the duration of his/her "red circled" rate.

ARTICLE 11 - PAID HOLIDAYS

11.01 All employees shall receive the following holidays and any holiday proclaimed by the Federal, Provincial or Municipal Government, at their regular rate of pay:

New Year's Day	Civic Holiday
Family Day	Labour Day
Good Friday	Thanksgiving Day
Easter Monday	Remembrance Day
Victoria Day	Christmas Day
Canada Day	Boxing Day

Should New Year's Day, Christmas Day, Boxing Day, Remembrance Day or Canada Day fall on other than an employee's regular working day and if it is not proclaimed or observed on a regular working day, an employee shall be entitled to one (1) day of holiday with pay for that day at a time mutually agreed to by the employee and his/her immediate Supervisor.

In the event that a paid holiday falls within an employee's vacation period, he/she will have the option of being granted an extra day of vacation at a time mutually agreed upon or pay therefore at the employee's regular rate of pay.

ARTICLE 12 - VACATIONS

12.01 Employees hired between January 1st and June 30 shall be entitled to one (1) day of vacation with pay at the employee's regular hourly rate for each complete month of service between the employee's start date and December 31 of the first vacation year to a maximum of ten (10) days.

12.02 Employees hired after June 30th shall be entitled to no vacation in that first year but to be paid at four (4) percent of their annual gross earnings effective December 31.

12.03 Employees on the active payroll with one (1) full year's continuous service shall be entitled to two (2) weeks vacation with pay in the year in which the one (1) year of service is completed and thereafter.

12.04 Employees on the active payroll with four (4) years continuous service shall be entitled to three (3) weeks vacation with pay in the year in which the four (4) years service is completed and thereafter.

12.05 Employees on the active payroll with ten (10) years continuous service shall be entitled to four (4) weeks vacation with pay in the year in which the ten (10) years service is completed and thereafter.

12.06 Employees on the active payroll with sixteen (16) years continuous service shall be entitled to five (5) weeks vacation with pay in the year in which the sixteen (16) years service is completed and thereafter.

12.07 Employees on the active payroll with twenty-six (26) years continuous service shall be entitled to six (6) weeks vacation with pay in the year in which the twenty-six (26) years service is completed and thereafter.

12.08 In the selection of dates, every effort will be made to allow the employees to exercise their choice in accordance with their seniority status. It is understood between the parties that a maximum of five (5) days vacation can be carried over into the subsequent year.

12.09

a) All time lost from work due to absences from work for any reason will reduce vacation pay entitlement in the same proportion as the factor by which periods of absence relate to the full vacation year with the following exceptions:

i.) Time off for paid sick leave under the sick leave credit system under the Collective Agreement;

ii.) Union leave under the Collective Agreement, excluding leaves to take a position within the Union.

iii.) **Maternity and Parental Leave, Jury Duty and Bereavement Leave.**

b) Notwithstanding the foregoing, time lost while in receipt of Workers' Compensation benefits either:

i.) exceeding sixty (60) working days, whether continuous or not in a vacation year; or

ii.) exceeding sixty (60) continuous working days spanning two (2) vacation years,

will reduce vacation pay entitlement in the same proportion as the factor by which the periods of absence relate to the full vacation year. Accumulated days can only be counted once in order to determine whether pro-rating is applicable.

c) Pro-rating of employees on Workers' Compensation under this clause will cease once the employee has returned to work and the Corporation has started to pay wages directly. Top-up payments will not be included as "wages paid directly".

d) In any of the foregoing circumstances, vacation pay entitlement shall be pro-rated taking into account the total length of the period of absence.

ARTICLE 13 - EMPLOYEE BENEFIT PLANS

13.01 The Employer shall provide, at no cost to the employees, except students, on the active payroll, who have completed three (3) months' of service, the benefits of the Ontario Health Insurance Plan.

13.02 **Life Insurance/LTD:** The Employer shall provide, at no cost to the employees, except students, on the active payroll, who have completed three (3) months of service, life insurance, including A.D. & D. in the amount of twice their basic salary, the amount to be the closest even one thousand dollars ($1,000). The Employer shall provide at no cost to the employees, except students and employees hired under a government subsidized program, on the active payroll who have completed three (3) months of service, a Long Term Disability Salary Replacement Program which will provide employees a payment of 75% of their monthly pay up to a maximum of four thousand dollars ($4,000) per month, subject to the one hundred and twenty (120) days waiting period and the conditions as set forth by the carrier. L.T.D. "Own occupation for two (2) years" shall be added to the terms of the L.T.D. Plan. Details of the Plan will be provided in the Employee Booklet. **Effective July 1, 2013 LTD change up to a maximum of five thousand dollars ($5000) per month with no Indexing of COLA.**

13.03 **Extended Health**: The Employer shall provide, at no cost to the employees, except students, on the active payroll, who have completed three (3) months' service, an Extended Health Plan on a pay direct non-deductible basis. Such coverage shall include the present benefits including:

Private and Semi-Private Hospital Coverage:

Vision Care: Effective April 1, 2012 - $260.00

One eye exam every 24 months – Effective April 1, 2012

Effective July 1, 2013 $375.00 every 24 months and one Eye Exam every 24 months

Hearing Aid:

Expenses to a maximum of five hundred dollars ($500.00), during a lifetime, subject to the carrier's limitations. **Effective July 1, 2013 Expenses to a maximum of Five hundred dollars ($500.00) every three years.**

Out of Country Emergency Coverage:

Out of Country Emergency Coverage with $1,000,000 lifetime maxium – trip duration of 60 days.

Chiropractic & Massage:

$200.00 Max per year – combined maximum with no requirement for physician authorization.

Effective July 1, 2013 $300.00 Max per year – combined maximum with no requirement for physician authorization.

a) If any employee retires and is in receipt of an early retirement pension from OMERS, the Corporation will provide them with the Extended Health Plan and the Dental Care Plan as provided in Articles 13.03 and 13.04 at their time of retirement until they reach the age of sixty-five (65) years.

b) The Employer agrees to make available optional group life insurance at group life rates for all retirees at no cost to the Employer.

13.04 **Dental:**
The Corporation shall pay 100% cost of the Insurance Plan Premiums to a Carrier on a cost sharing basis, 80% by the Employer, 20% by the employee, for employees, except students, on the active payroll, who have completed three (3) months' service, a basic Dental Care Plan to include denture repair and re-lining and complete dentures at 50% deductible. The current O.D.A. schedule rates will apply and a $2,000.00 max per year. **Effective July 1, 2013 add Orthodontic coverage at 50% co-insurance for dependent children to a lifetime maximum of $1,500.00**

13.05 The Carrier of such insurance benefits and other benefits as outlined in 13.02, 13.03, and 13.04, will be the Employer's choice. Should the Carrier be changed during the term of this Agreement, the insurance coverage shall be no less than those presently being provided to the employees.

a) The Corporation may substitute a plan underwritten by a carrier other than Manulife provided such plan provides same or better coverage at no extra cost to the employee. The agreement of the Union is required.

13.06 The Employer agrees to apply by September of each year for a reduction in the premium payment under the provisions of the E.I. if the present sick leave plan meets the criteria for such reduction. Any reduction in the employees' contributions will be refunded to the employee in a lump sum as prescribed in the regulations

13.07 Subject to the provision of the collective agreement and legislation, benefit coverage will continue only for absences due to **layoff,** illness, disability and workers' compensation. Such benefit coverage will cease when an absence from work exceeds one hundred and twenty (120) consecutive days. "Benefit Coverage" includes life insurance, AD.&D., L.T.D., Extended Health Plan and Dental Plan.

13.08 **O.M.E.R.S.**: In addition to the Canada Pension Plan, eligible employees shall join the Ontario Municipal Employee's Retirement System Plan (O.M.E.R.S.). The Corporation and the employee shall make contributions in accordance with the provisions of the O.M.E.R.S. Plan

13.10 **Sick Leave**:

a) Each employee who has completed his/her probationary period shall be credited with one and one-half (1-1/2) days' sick leave for each calendar month of service with the Employer. Each employee shall continue to accumulate sick leave during the first five (5) absences in any calendar year. However, for any and all subsequent periods of absence, there shall only be a one (1) day accumulation during the month or months in which such absences occur. There shall be no cash-out provision on the accumulation of sick leave credits after September 1, 1998.

b) All accumulated sick leave credits shall be addressed in accordance with Appendix C of this Collective Agreement.

c) (i) All employees will receive a sick leave credit at the rate of one and one-half (1 ½) days per month until such sick leave credit reaches (one hundred and seventy (170) days.

(ii) Notwithstanding the provisions of Article 13.14, students shall be entitled to accumulate sick leave at the rate of one and one-half (1 ½) days per month from the date of commencement of employment. Such entitlement shall not be cumulative from one work term to another and there shall be no cash-out provision.

d) The sick leave bank will be deducted for each absence and upon return to work the sick leave bank will be credited at one and one-half (1 ½) days per month until the bank is reimbursed up to a maximum of one hundred and seventy (170) days. Should an employee not have sufficient credits to qualify for the one hundred and twenty (120) day waiting period in his/her active bank, he/she **will be issued an ROE and/** or may use the sick leave bank credit **in accordance with Appendix 'C".**

13.11 When an employee is given a leave of absence without pay for any reason for more than one (1) week, or is laid off on account of lack of work and returns to the service of the employer upon expiration of such leave of absence, he/she shall not receive credit for the period of such absence, except as may be otherwise approved and authorized by the Employer, but shall retain his/her cumulative sick leave credit, if any, existing at the time of such leave.

13.12 The number of days or parts of days for which an employee received "sick pay" shall be deducted in hours from his/her cumulative sick pay credit.

13.13

a) (i) In order to qualify for sick leave pay, employees are required to arrange to have their immediate Supervisor notified of their inability to be at work. It is understood that employees may use sick leave for attendance at Doctor's or Dentist's appointments. However, such appointments shall not be counted as absence under Article 13.10 (a).

~~(ii) Notwithstanding the provisions of (a) (i) above, students, for each absence of two~~ (2) working days duration, shall present a Doctor's certificate as defined in Article 13.13(a) (i) to the Employer prior to the student returning to his/her duties.

(iii) Upon return to work after a period of three (3) days absence due to illness or disablement, it is the responsibility of the employee to produce a certificate from a duly qualified medical practitioner certifying they are now fit to resume their regular duties. Forms for this purpose are available from his/her immediate supervisor. The Employer, however, after the fifth period of absence in any calendar year may require a medical certificate for any period of illness or disablement.

In the case of sickness or disablement lasting three (3) days or more, employees are required to produce a certificate from a duly qualified medical practitioner verifying their inability to attend work and certifying that they are not fit to resume their regular duties or modified duties.

b) **Family Illness**: An employee shall be allowed to use five (5) days of sick leave accumulation per annum for absences due to the illness of a spouse, child or parent. For one (1) day's absence no medical certificate shall be required; for longer periods, an employee shall be required to produce a certificate from a qualified medical doctor certifying the illness. Such periods of absence shall be deducted from the sick leave bank but shall not be counted as absence under Article 13.10 (a). It is expressly understood that the provisions of this Article are intended for emergency illnesses. An employee shall not be guaranteed payment for such leave of absence should he/she be aware of scheduled treatment which requires hospital confinement more than five (5) calendar days prior to such confinement.

It is expressly understood that the provisions of this Article are intended for emergency illnesses. It is further understood that "emergency illnesses" means an unforeseen combination of circumstances that requires immediate action.

c) An employee transporting his spouse to or from the hospital due to pregnancy or when he/she is required to attend his/her family member in the hospital, shall be granted such leave.

13.14 Any or all of the unused portion of the sick pay credit shall be accumulated to the benefit of the employee from year to year. The unused portion of the yearly accumulation shall be computed at the end of each year and brought forward in days.

An employee's sick leave credit shall be available for scrutiny by the employee concerned in the presence of the Employer's Human Resource representative. A Union representative may, with permission of the employee concerned, scrutinize that employee's sick credit record.

13.15 **W.S.I.B.** When an employee is absent due to a workplace accident and is in receipt of Workplace Safety and Insurance Benefits, the Corporation will when requested by the employee, make up the difference between the benefit allowance and the employee's net pay. At no time is the benefit top up to exceed 100% of the employee's net pay.

The top up amount will be debited by the appropriate number of hours from the employee's sick leave credits. Employees returning to work from a workplace accident shall be required to submit a medical certificate from a duly recognized practitioner verifying that the employee is able to return to work.

13.16 **Frozen Sick Leave: In accordance with article 13.10 (b)** Upon termination of employment an employee shall be entitled to one-half (½) of the number of sick days standing to his/her credit in the frozen sick leave bank on the basis of the employee's regular weekly basic rate of pay divided by five. The amount shall be the maximum of six (6) months' salary. In the event of death, this cumulative sick leave credit shall be paid to the employee's beneficiary.

13.17 The parties agreed that the employee's sick leave credits will not be posted on the Seniority List, however, it is understood that employees will have access to their sick leave credit and balance.

ARTICLE 14 – CLOTHING

14.01 All personnel will be supplied with uniforms, protective clothing and/or safety apparel. Such clothing and/or safety apparel shall be kept available by such personnel at all times for their use as conditions dictate and/or as required by the Employer.

14.02 **Employees on the active payroll and on the seniority list who require C.S.A. approved Safety footwear shall be entitled, on a calendar year basis, to be reimbursed upon presentation of a receipt, for the purchase of C.S.A. approved Safety footwear. Single or multiple purchases of C.S.A. approved safety footwear within the calendar year by an employee shall be limited to a maximum of one hundred and forty dollars ($140.00).**

ARTICLE 15 - UNION DUES

15.01 The Employer agrees to deduct from each pay of each calendar month from employees, including students, a sum equivalent to the amount of Union dues and/or assessments as advised by the Union.

15.02 The Employer shall remit, prior to the 15th of the month, such amount to the Secretary-Treasurer of the Union together with a monthly statement listing members of the Union on whose behalf such deductions have been made.

ARTICLE 16 - LEAVE OF ABSENCE

16.01

a) Leave of absence without pay and without loss of seniority may be granted for legitimate personal reasons. It is understood that any application for leave of absence is subject to reasonable notice in writing to the respective Director or designate and in the event any such leave of absence is not used for the purpose granted, the employee is subject to discipline which may include dismissal.

b) Any employee who is selected for a full time position with the Union shall be allowed or given a leave of absence by the Employer without loss of seniority and without pay, but there shall be no accumulation of seniority during such absence. Such leave of absence shall be subject to annual renewal upon application to the respective Director and such renewal shall not be unreasonably withheld.

16.02

Employees requesting time off for the purposes of Union conventions or other union business not connected with this agreement shall be granted such time off without pay subject to the following conditions:

a) When the Union requests time off without pay for an employee or employees to perform Union business, and if such time off is granted, the Union shall reimburse the Corporation for the continuance of such employees on the payroll.

b) Upon application in writing to the Employer's designated Human Resource representative by the Recording Officer of the Union, a maximum of two (2) employees from the Unit shall be allowed or given a leave of absence with pay and without loss of seniority to attend such Union convention and/or seminar as a delegate of the Union. Such leave of absence shall not exceed five (5) working days' duration at any one time.

c) Application for such leave of absence shall be made at least ten (10) working days prior to the commencement of such leave. The granting of such leave shall be subject to the efficiency of the operation but shall not be unreasonably withheld.

c) The payment in any one calendar year shall be deducted from the twenty-eight (28) day maximum allotment..

16.03 Union members on authorized Committees, including Grievors, meeting with the Employer on grievance up to and including Arbitration, or negotiations up to and including conciliation, or at any other mutually agreed meeting, will be given a leave of absence without loss of pay.

16.04 Pregnancy/Parental and Adoption leaves of absences shall be in accordance with the Employment Standards Act and amendments made thereto.

The employee who is granted such leave shall be responsible for maintaining the full amount of the self-pay premiums of Ontario Health Insurance Plan and the Group Benefit Plan.

16.05 **Bereavement**: The Employer shall grant an employee a leave of absence of a **maximum** of **five (5)** days without loss of pay upon the death of a member of his/her immediate family for the purpose of mourning. **"Immediate family" shall mean an employee's spouse, children, step-children, parent or step-parent.**

The Employer shall grant an employee a leave of absence of a **maximum** of three (3) days without loss of pay upon the death of a member of his/her **family** for the purpose of mourning. **"Family" shall mean an employee's grandchildren, grandparents, brothers, sisters, step-brothers, step-sisters, parents of current spouse, spouse of brother or sister and sister or brother of spouse.**

In cases where interment is delayed, an employee shall be provided with the opportunity of utilizing the total days allowed under this Article for bereavement purposes and/or interment.

16.06 Up to two (2) employees, designated by the Union, shall be allowed time off (not to exceed one-half (l/2) day for each employee), with pay to attend the funeral of a fellow employee or retired employee as Representatives of the Union.

16.07 Jury/Witness Duty

Employees who are required to serve as jurors, or subpoenaed as a witness in any court in Ontario shall be granted a leave of absence for this purpose upon application to the respective Director or designate. Such leave shall not constitute a break in service for the calculation of seniority. Upon completion of jury or witness service, such employee shall present to his/her immediate Supervisor a satisfactory certificate showing such period of service. Such employee will be paid his/her full salary for the period of such jury service or witness service provided he/she shall deposit with the Employer, through their respective Department the full amount of the compensation received, excluding mileage and travel expense, and an official receipt therefore. However, should the employee present himself/herself for the selection as a juror and not be selected, then he/she shall be required to return to his/her regular employment to complete his/her remaining normally scheduled work day.

ARTICLE 17 - TECHNOLOGICAL CHANGE

17.01 Technological Change - Advance Notice

The Employer shall notify the Union three months before the introduction of any **substantial** technological change. The Labour-Management Committee will discuss Technological Change as it affects employees in advance of any implementation.

17.02 Technological Change - Income Protection

An employee who is displaced from his/her job by virtue of technological change will suffer no reduction in normal earnings for a period of six (6) months from date of implementation.

17.03 Technological Change - Training Benefits

Where new or greater skills are required than are already possessed by affected employee(s) under the present methods of operation, such employee(s) shall, at the expense of the Employer, be given a period of time not to exceed the six months during which they may perfect or acquire the skills necessitated by the new method of operation.

17.04 Additional Training:

Should a need for the perfection or acquisition of skills require a training period longer than six months, the additional training time shall be a subject for discussion between the Employer and the Union.

ARTICLE 18 - GENERAL

18.01 The Employer recognizes and accepts the provisions of this Agreement as binding upon itself and upon each of its duly authorized representatives and pledges that it and each of its duly authorized representatives shall observe the provisions of this Agreement.

18.02 The Union recognizes and accepts the provisions of this Agreement as binding upon itself, each of its duly authorized officers, representatives and employees represented by the Union and pledges that it, each of its duly authorized officers and representatives and the employees covered by this Agreement, shall observe the provisions of this Agreement.

18.03 Employees authorized to use their private vehicles will be compensated for such use per the Corporation Policy (as amended); rate for casual drivers for all distances necessarily traveled in carrying out the requirements of their job.

18.04 The Recording Secretary of the Union shall, after any change of officers of the Union, send a list of the changes to the Human Resources Department within ten (10) days of such changes.

18.05 The Unit Chairperson of the Union shall notify the Human Resources Department of the Employer in writing, designating the personnel constituting the Bargaining Committee for the said Union at least three (3) months prior to the termination of this Agreement.

18.06 All words in this Agreement in singular and masculine shall, when the context so requires, include the plural or the feminine. All words in this Agreement that pertain to gender shall, wherever possible, be gender neutral.

18.07 Notices required to be given under any of the provisions of this Agreement shall, in the case of the Union be directed to the Unit Chairperson; in the case of the Employer, be directed to the Director of Human Resources, except as otherwise designated.

18.08 Appendixes **"A", "B", "C", "D", "E", "F", and "G"** attached hereto form part of this Agreement.

18.09 In the event of development of **a Consolidation** involving the **Brantford Power Inc.** and affecting the employees of this Agreement, the **Employer** shall notify the Secretary of the Union **as soon as practicable** give the Union reasonable notice of any organizational change necessitating terminations of employment or other significant change in the employment status of the employees in order that the Union may be given an opportunity to discuss such matters **in keeping with Appendix "A".**

18.10 The parties agree that it is in the interest of everyone concerned to have a Health and Safety Committee. A minimum of two (2) representatives each from the Union and the Employer shall sit on the Committee. The function of the Health and Safety Committee will be determined by the Health and Safety Committee from time to time to deal with any matter concerning health and safety referred to it by either party to this Agreement.

Note: Subject to approval from the Ministry of Labour the Parties agree to form a Multi-workplace Joint Health and Safety Committee.

18.11 Employees employed in positions, which require a Professional Designation as a condition of employment shall be entitled to receive reimbursement for the payment of such professional membership dues.

ARTICLE 19 - DURATION

19.01 Unless changed by mutual consent, the terms of this Agreement shall continue in effect until **March 31, 2014** and shall continue automatically thereafter for annual periods of one (1) year each unless either party notifies the other in writing within the period of three (3) months immediately prior to the expiration date that it desires to amend the Agreement.

19.02 Negotiations shall begin within fifteen (15) days following notification for amendment, as provided in the preceding paragraph.

19.03 If pursuant to such negotiations, an agreement is not reached on the renewal or amendment of this Agreement, or the making of a new Agreement prior to the current expiry date, this Agreement shall continue in full force and effect until a new Agreement is signed between the parties or until conciliation proceedings prescribed under the Ontario Labour Relations Act, R.S.O., 1995, have been completed, whichever date should first occur.

IN WITNESS WHEREOF each of the parties has caused this Agreement to be signed by their duly authorized officials or representatives as of this 10 , day of OCT **2013.**

Brantford Power Inc.	**C.U.P.E. Local 181, Brantford Power Unit**
Paul Kwasnik, Chief Executive Officer	Andrew Hunter, National C.U.P.E. Representative
Brian D'Amboise, Chief Financial Officer	Bill Burden, Unit Chair Local 181 –Brantford Power
Heather Wyatt, Director of Regulatory Affairs	Domenic D'Amato, Negotiation Committee
Altaf Hussain, Director Engineering & Construction	Mike Armstrong, Negotiation Committee
Roland Boutette, HR Representative (Labour Relations)	Jim, Ray, Negotiation Committee

Schedule "A"

Positions listed as of April 1, 2012

Through the Job Evaluation process, the Parties agree to maintain and update Schedule "A" as required. Revised Schedule "A's" shall be provided to the Union Executive and the Human Resources Department as they occur and shall be provided to the membership of the bargaining unit January 1st annually.

		Effective	Minimum Rate 90%	3 Month Rate 94%	After 1 Year 97%	After 2 Years 100%
Level 1	0 - 200	01-Apr-12	$16.616	$17.354	$17.908	$18.462
		31-Mar-13	$16.865	$17.615	$18.177	$18.739

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 2	201 - 230	01-Apr-12	$18.400	$19.217	$19.831	$20.444
		31-Mar-13	$18.675	$19.506	$20.128	$20.751

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 3	231 - 260	01-Apr-12	$20.206	$21.104	$21.777	$22.451
		31-Mar-13	$20.509	$21.421	$22.104	$22.788

Level 3 Positions

Administrative Assistant – Brantford Power

Billing Services Representative

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 4	261 - 290	01-Apr-12	$21.992	$22.969	$23.702	$24.435
		31-Mar-13	$22.322	$23.314	$24.058	$24.802

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 5	291 - 320	01-Apr-12	$23.787	$24.844	$25.637	$26.430
		31-Mar-13	$24.143	$25.216	$26.021	$26.826

Level 5 Positions

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 6	321 - 350	01-Apr-12	$25.571	$26.707	$27.560	$28.412
		31-Mar-13	$25.954	$27.108	$27.973	$28.838

Level 6 Positions

AM / FM Specialist & CADD Operator

Conservation Program Advisor

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 7	351 - 380	01-Apr-12	$27.379	$28.596	$29.508	$30.421
		31-Mar-13	$27.789	$29.024	$29.951	$30.877

Level 7 Positions

Customer Service / Billing Representative

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 8	381 - 410	01-Apr-12	$29.163	$30.459	$31.431	$32.403
		31-Mar-13	$29.600	$30.916	$31.902	$32.889

Level 8 Positions

Credit/Collection Representative

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 9	411 - 440	01-Apr-12	$30.958	$32.334	$33.366	$34.398
		31-Mar-13	$31.423	$32.819	$33.867	$34.914

Level 9 Positions

Electrical Construction Inspector

Electrical System Planner

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 10	441 – 470	01-Apr-12	$32.742	$34.198	$35.290	$36.381
		31-Mar-13	$33.234	$34.711	$35.819	$36.927

Level 10 Positions

Electrical Engineering Technologist (*)

Financial Analyst

		Effective	Minimum Rate	3 Month Rate	After 1 Year	After 2 Years
Level 11	471 - 500	01-Apr-12	$34.540	$36.075	$37.227	$38.378
		31-Mar-13	$35.059	$36.617	$37.785	$38.954

SCHEDULE "B"

Students Schedule of Rates - Clerical - Weekly - Based on 33-3/4 Hours per week

Vacation Period / Work Term		01-Apr-12	31-Mar-13	
1		$12.099	$12.099	
2		$12.686	$12.686	
3		$13.220	$13.220	
4		$13.757	$13.757	
5		$14.304	$14.304	
6		$15.009	$15.009	
7		$15.544	$15.544	

- University Students are to start at Work Term 2

- **Students Schedule of Rates - Non-Clerical - Weekly - Based on 40-Hours per week**

Vacation Period / Work Term		01-Apr-12	31-Mar-13	
1		$13.366	$13.366	
2		$13.848	$13.848	
3		$14.266	$14.266	
4		$14.722	$14.722	
5		$15.219	$15.219	
6		$15.701	$15.701	
7		$16.223	$16.223	

- University Students are to start at Work Term 2

The above rates applicable to Students shall be considered as minimum rates.

APPENDIX "A"

Letter of Understanding
Between
Brantford Power Inc.
And
The Canadian Union of Public Employees, Local 181
Brantford Power Unit

Terms of Reference for Labour Management Committee

The parties agree to maintain a Labour / Management Committee for the purpose of discussing issues relating to the workplace that affect the parties and/or employees bound by this Agreement.

(1) Function of the Committee:

The function of the committee is to facilitate discussion and resolution on matters of interest to the Corporation and employees, to promote and maintain a work environment which fosters employee engagement.

Every reasonable effort will be made by both parties to facilitate representation of both the employees and employers interests at the Labour Management Committee.

(2) Purpose of the Committee:

To investigate, study and discuss possible solutions to mutual problems affecting labour-management relations.

The Labour/Management Committee shall have no authority to change, delete or modify any terms of the Collective Agreement, or to settle grievances arising under this Agreement.

(3) Issues to be discussed:

Not limited to the following:

- New full-time positions established by the Corporation to determine the non-union or union status of the position. Should the parties not agree on the status of the position, the union may proceed to binding arbitration within 30 days, otherwise, the Corporation will proceed to fill the new position.
- Changes in the organizational structure
- Paid holiday schedule

- Technological change
- Short and long term planning of the Corporation
- Review contract positions

(4) Representation:

Management: Up to three (3) management representatives may attend the meeting and a human resources representative to assist the management representatives.

Union: Up to three (3) bargaining unit employees may attend, one (1) of which must be the unit chair or their designate, and the CUPE national representative.

Each party will designate a co-chair and will alternate chairing the meetings.

(5) Meetings:

The parties agree to meet upon request of either party.

The parties will meet no more than four (4) times per year, unless both parties mutually agree to meet more often.

The party requesting to meet shall prepare and distribute an agenda one (1) week in advance of the meeting.

A record of mutually agreed upon decisions will be kept and posted.

The terms of reference may be changed upon mutual agreement of the parties.

Dated this day of December, 2012.

Brantford Power Inc.	**C.U.P.E. Local 181, Brantford Power Unit**

APPENDIX "B"

Letter of Understanding
Between
Brantford Power Inc.
And
The Canadian Union of Public Employees, Local 181
Brantford Power Unit

Market Value Positions
The Parties recognize the dynamics of the job market and situations where there could be an increased temporary demand for certain types of skills and positions. With mutual agreement of the parties, the Employer may pay market sensitive positions in a higher band in order to respond to these circumstances.

Where objective market data has been provided to the Union such agreement will not be unreasonably withheld by the Union.

Dated this day of December, 2012

Brantford Power Inc.	**C.U.P.E. Local 181, Brantford Power Unit**
______________________	______________________
______________________	______________________
______________________	______________________
______________________	______________________
______________________	______________________

APPENDIX "C"

Letter of Understanding
Between
Brantford Power Inc.
And
The Canadian Union of Public Employees, Local 181
Brantford Power Unit

Former PUC/HEC Employees

The Parties agree to the following in regard to the following bargaining unit employees:

Employee	Position Title	Seniority Date
Bennett, Mary	Switchboard / Receptionist	04/29/85
Feige, Ursula	Credit Clerk	09/09/85

1. These employees will work thirty-five (35) hours per week.

2. If an aforementioned employee's sick leave accumulation became vested under the Policy of the former PUC/HEC for the purpose of payout on September 1, 1998, the employee will receive a letter showing the amount of leave that was vested, if any. Any time in an employee's bank as of that date that was not required to maximize the payout will be placed in the active sick leave bank under this Collective Agreement.

3. An employee not eligible for vesting have had their sick bank continued since that time and would bring that with them into the unit.

Dated this day of December, 2012

Brantford Power Inc.

C.U.P.E. Local 181, Brantford Power Unit

APPENDIX "D"

Letter of Understanding
Between
Brantford Power Inc.
And
The Canadian Union of Public Employees, Local 181
Brantford Power Unit

Incumbency Rates

The Parties agree that the position of Administrative Assistant, currently occupied by M. Bennett, as a result of the C.U.P.E. Job Evaluation Plan has been "red circled" and is considered to have "incumbency rates". M. Bennett will receive the full economic increase negotiated while M. Bennett remains the incumbent in that position.

Dated this day of December, 2012.

Brantford Power Inc.	C.U.P.E. Local 181, Brantford Power Unit

APPENDIX "E"

Letter of Understanding

Between Brantford Power Inc.

And

The Canadian Union of Public Employees and its Local 181

- Brantford Power Unit

Re: Intermingling of Bargaining Unit Work and Article 2.03
(Without prejudice or precedent to any matter arising between the Parties)

Notwithstanding Article 2.03 of the Collective Agreement this will confirm that there has been intermingling of bargaining unit work since April 1, 2012 and both parties agree to continue this for the term of this agreement.

Dated at the City of Brantford this 30th day of April, 2013

Brantford Power Inc.	**C.U.P.E. Local 181, Brantford Power Unit**

APPENDIX "F"

Letter of Understanding
Between Brantford Power Inc.

And

The Canadian Union of Public Employees and its Local 181

- Brantford Power Unit

Re: Acting Pay for coverage of Supervisor of Customer Service Position

1. When a Customer Service Staff is designated to fill in for a supervisor, the incumbent will be paid a premium of $0.95 per hour above their rate of pay for hours worked.

2. The rate of pay for the incumbent performing Acting duties for the "Supervisor of Customer Service" (as in paragraph 1 above) shall be issued to the incumbent where the incumbent is assigned to perform the duties of "Supervisor of Customer Service" and it is approved by management.

3. This Letter of Understanding shall be applied retro to April 29th, 2013, and shall continue for the term of this collective Agreement.

Dated at the City of Brantford this 30th day of April, 2013

Brantford Power Inc.

C.U.P.E. Local 181, Brantford Power Unit

"G" AA

APPENDIX "~~E~~" RB

Letter of Understanding
Between
Brantford Power Inc.
And
The Canadian Union of Public Employees, Local 181
Brantford Power Unit

Re: Car Allowance

Any employee currently receiving this benefit as of April 1, 2012 and who is required to have a vehicle available as a condition of employment *, shall continue to be paid the $5 /day car allowance till such time as the incumbent leaves the position or the Employer provides a vehicle to the incumbent.

*(This condition shall be included on each employee's Job Description and applicable Job Postings and are marked with an * in Schedule "A").

Employees authorized to use their private vehicles for Employer's business shall be entitled to receive the difference in insurance premium (up to $80.00) applicable to business use as against pleasure and work use for public liability, property damage, collision and comprehensive. Such compensation shall be paid within two (2) weeks of the employee producing a receipt for same to his/her immediate Supervisor. All employees required to use such private vehicles on Employer business shall be required to have such public liability and property damage coverage.

In the case of an employee who is entitled to the car allowance and who is absent from work on sick leave or Workers' Compensation, the car allowance shall be paid for the month in which the employee ceased working and the following month only. The employee shall receive car allowance again on his/her return to work commencing with the month in which they returned.

Dated at the City of Brantford this 10 day of Oct, 2013

Brantford Power Inc.

C.U.P.E. Local 181, Brantford Power Unit

Collective Agreement

Between

The Corporation of the City of Brantford

And

The International Brotherhood Of Electrical Workers Local 636, Unit 45

June 1st, 2010 to May 31st, 2013

(POWER)

Index

THIS AGREEMENT entered into at Brantford, Ontario, this 30th day of September 2010

between

THE CORPORATION OF THE CITY OF BRANTFORD

(Hereinafter referred to as the "Corporation")

OF THE FIRST PART

and

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL 636, UNIT 45

(Hereinafter referred to as the "Union")

OF THE SECOND PART

ARTICLE 1 - RECOGNITION AND COVERAGE

1.01 The Corporation recognizes the Union as the exclusive collective bargaining agent for all its employees within the Power and Stores Departments, save and except non-working forepersons, persons above the rank of non-working foreperson and all administrative staff, office staff, **student hired throughout the summer months and co-op students hired during their work terms.**

ARTICLE 2 - MANAGEMENT FUNCTIONS

2.01 The Union acknowledges that it is exclusively the function of the Corporation to:

(a) Maintain order, discipline and efficiency;

(b) Hire, discharge, direct, promote, demote, lay off and suspend or otherwise discipline employees subject to the provisions of this agreement provided that a claim of discriminatory promotion, demotion or layoff, or that an employee has been unjustly discharged or disciplined, may be treated as a grievance procedure;

(c) Maintain and enforce rules and regulations to be observed by the employees;

(d) Generally to manage the operations and undertakings of the Corporation and, without restricting the generality of the foregoing, to determine the methods, procedures, machinery and equipment to be used, the schedules and programming of projects and to exercise all other customary functions of management.

2.02 The Corporation agrees that these functions will be exercised in a manner consistent with the provisions of this agreement.

ARTICLE 3 - RELATIONSHIP

3.01 The Corporation and the Union agree that there will be no discrimination exercised or practiced by either of them or their representatives or members because of an employee's membership or non-membership in the Union.

3.02 The Corporation agrees to give three (3) months' written notice to the Union of any planned technological change that may result in the reduction of the Union's work forces.

3.03 In the event of technological change that may result in employees being placed in a different job classification, or displaced due to lack of work, such employees will be given preferential consideration to be trained in new skills or new jobs, provided such employees have the qualifications for such training and provided such job opportunities exist.

3.04 All communications relating to matters arising out of this Agreement shall be addressed and delivered to the Business Representative of the Union, and his/her designate. All communications required by this Article shall be copied to the unit Chairperson.

3.05 The two parties to this Agreement shall establish a Labour Management Committee of four (4) members, with two (2) members from each side, which shall meet quarterly or at other times that may be mutually agreed upon.

ARTICLE 4 - GRIEVANCE PROCEDURE

4.01 Any difference concerning the interpretation, application, administration or alleged violation of the provisions of this Agreement, except with respect to the discharge of a Probationary Employee, shall be dealt with in the following manner:

STEP 1

1. A Regular Employee wishing to present a grievance shall submit the grievance in writing to the Immediate Supervisor, indicating the nature of the grievance and the remedy sought within ten (10) working days after the occurrence of the circumstances giving rise to it. The Immediate Supervisor shall reply within three (3) working days after having received the grievance.

STEP 2

2. If the reply of the Supervisor is not satisfactory to the Employee concerned, the written grievance shall be referred to the Director/Department Head within five (5) working days after the reply of the Immediate Supervisor. The Director/Department Head shall meet with the Employee and members or designates of the Grievance Committee of the Union within five (5) working days to discuss the grievance. A reply to the grievance shall be given in writing within five (5) working days after the meeting has been held at this stage of the grievance procedure.

3. Any of the time allowances provided in (1) and (2) of this Article may be extended by mutual agreement between the parties concerned.

4. If a grievance is to be referred to arbitration, it shall be so referred within twenty (20) working days after the date of the reply referred to in Item 2 above.

5. In the event of a group grievance, a policy grievance or a grievance respecting the discharge or suspension of a Regular Employee, the grievance shall be in writing, indicating the nature of the grievance and the remedy sought. The grievance will be processed commencing at Step 2 Director/Department Head of the grievance procedure. This clause shall not be used for the purpose of abridging the right of the Employee to process grievances, nor shall it be used for the purpose of submitting matters to be handled through the grievance procedure by Employees.

6. The Grievance Committee shall consist of the Steward, the Grievor, and the Unit Chairperson or his/her designate, and the Area Representative, who will meet at Step 2 of the Grievance Procedure.

7. If either the Union or the Corporation claims there has been a violation or misinterpretation of the terms of this Agreement by the other party, it may state such claim in writing, which will be processed as a grievance commencing at Stage Two of the grievance procedure.

8. All steps of the grievance procedure, including any meetings with a Grievance Mediation Officer, shall be held during regular hours of work, with no loss of regular wages.

4.02 The Corporation will recognize a Negotiating Committee of not more than four (4) employees to represent the Union in meetings with the Corporation in negotiation of this Agreement. The Corporation will pay the employees for any normal working time lost at such meetings, up to but not including conciliation. The Union Negotiating Committee shall be accompanied by the Local Union Business Representative and/or a Representative of the International Brotherhood of Electrical Workers at any meeting. There will be a maximum of two (2) employees from the line department unless it is operationally feasible whereby the maximum will not apply.

It is understood that Union Committee members and stewards have their regular duties to perform on behalf of the Corporation and that these will normally take pre-eminence. However, if it is necessary for a committee member or steward to attend Union business or investigate a grievance during working hours they shall not leave their workplace without first obtaining permission from their supervisor. Such permission shall not be unreasonably denied.

4.03 All decisions arrived at between the representative of the Corporation and of the Union shall be final and binding upon the Corporation, the Union, and the employee or employees concerned.

4.04 Saturdays, Sundays and paid holidays as defined in Article 17, will not be counted in determining the time within which any action is to be taken or completed in each of the steps of the grievance procedure or under Article 5.

4.05 Failure of the grievor or the Union to process a grievance procedure within the time limit specified shall not be deemed to have prejudiced the Union on any similar grievance.

4.06 An employee shall have the right to request Union representation at any formal interview with management.

4.07 A letter of reprimand or suspension will be removed from the record of an employee twenty-four (24) months following the receipt of such letter or suspension provided that the employee's record has been discipline free for a twenty-four (24) month period.

ARTICLE 5 – ARBITRATION

5.01 Where a difference arises as to interpretation, application, or administration of this Agreement, including any question as to whether a matter is arbitrable, or where an allegation is made that this agreement has been violated, either of the parties, may after exhausting any grievance procedure established by this agreement, notify the other Party in writing not later than (20) working days after the expiration of the time limits defined under Step No. 2, of its desire to submit the difference or allegation to arbitration. When either party to this agreement requests that a grievance be submitted to arbitration, it shall make such request in writing - Correspondence on this matter will be addressed to the Unit Chair of the IBEW Local 636 Unit 45 with a copy to the Business Manager, and the Human Resources Director for the Corporation. Within five (5) working days thereafter, the party receiving the request will appoint a nominee. The two (2) nominees will attempt to select, by agreement, a third person, who will act as Chairman of the Arbitration Board.

5.02 If the party receiving the request for arbitration fails to appoint a nominee within five (5) working days, or the two nominees fail to agree on a third person to act as Chairman, the matter will be referred to the Ontario Labour Relations Board, which shall be requested to make the necessary appointments.

5.03 The grievance may be submitted to a single Arbitrator, if the parties mutually agree, as provided through the Ontario Labour Relations Board.

5.04 ~~Notwithstanding the provisions for an Arbitration Board, either party may request the~~ Minister to refer any grievance to a single arbitrator to be appointed by the Minister in accordance with the Ontario Labour Relations Act (Section 49), as amended.

5.05 No person may be appointed who has been involved in any attempt to settle the grievance being arbitrated.

5.06 Except by mutual agreement between the parties to this Agreement, no matter may be submitted to arbitration which has not been properly carried through the grievance procedure.

5.07 The Arbitrator or Arbitration Board shall not be authorized to render any decision inconsistent with the terms of this Agreement, nor shall they alter, modify, add to or amend any of its provisions.

5.08 The proceedings will be expedited by the parties to this Agreement. A unanimous or majority decision will be final and binding upon both the Corporation and the Union but, in the case of a Board, should a majority decision not be given, then the decision of the chairman will be final and binding.

5.09 Each of the parties hereto shall bear the expenses of the nominee it appoints, and the parties shall jointly bear the expenses, if any, of the Chairman or the Board or the single Arbitrator.

5.10 Wherever arbitration Board is referred to in the Agreement, the parties may mutually agree to appoint a single arbitrator.

ARTICLE 6 - NO-STRIKE AND NO-LOCKOUT

6.01 The Union agrees that there shall be no strike (as defined in the Ontario Labour Relations Act) and the Corporation agrees that there shall be no lockout (as defined in the Ontario Labour Relations Act).

ARTICLE 7 – SENIORITY

7.01 During the first 6 months of employment, all employees shall be considered on probation. Any absences from work totaling more than 10 working days in the 6 month period will extend the probationary period by an equivalent number of working days. After completion of the probationary period, the employee's name shall then be credited with 6 months seniority. For the purpose of this Article, there shall be a separate Brantford Power Department (including Metering, and Customer Service Division), and Purchasing and Stores Division seniority list.

7.02 When making lay-offs and recalls of employees, departmental seniority shall apply, providing the employee has the necessary qualifications and ability to perform the work available.

7.03 Any permanent employee covered by the bargaining unit who is promoted to a position outside of the bargaining unit shall retain their seniority for a period of twelve (12) months. Employees returning to their former classifications from outside of the bargaining unit shall be granted their seniority for up to six (6) months when being reclassified back into the bargaining unit.

7.04 Employees shall lose all seniority and will no longer be employees of the Corporation if they:

(a) Voluntarily quit the employ of the Corporation;

(b) Are discharged for cause, unless reversed through the grievance procedure;

(c) Are laid off for a period of more than twelve (12) months, or are laid off for a period of one (1) month with seniority of less than one (1) year (accumulative), temporary student labour to be excluded.

(d)(i) Fail to report for work within ten (10) days after being notified by registered mail sent to the last address registered with the Corporation to return to work following a lay-off;

(ii) Fail to notify the Human Resources Department within three (3) days after receipt of such notice of their intention to report for work;

(iii) Fail to report for work for three (3) days without leave of absence or without notifying their immediate supervisor. If the immediate supervisor is unavailable, another supervisor in the work unit may be notified. If the employee is too ill to telephone, the employee's spouse or other close relative may notify the appropriate supervisor;

(e) Are still absent from duty due to illness or non compensable injury after twenty-four (24) months of being on Long Term Disability, or when declared totally disabled by the Insurance Company, whichever is the earlier of the two.

7.05 It shall be the duty of employees to notify the Human Resources Department promptly in writing of any change of their address. If an employee shall fail to do this, the Corporation will not be responsible for failure of a notice to reach employee's address.

ARTICLE 8 - VACANCIES AND CLASSIFICATION

8.01 Vacancies existing, or new bargaining unit jobs created in the Brantford Power Department (including Metering and Customer Service Division) and Purchasing & Stores Division, shall be posted on the bulletin boards for seven (7) working days.

Written applications from employees shall be filed with the Corporation within nine (9) calendar days of posting. Where applicants are equally qualified for the opening, the applicant with the greatest seniority shall be given preference.

8.02 The Corporation agrees that the Human Resources Department will consult with the Unit Chairperson prior to making the appointment to a new position, or a new classification, or where a reclassification is involved, and will notify the Business Representative of the Union of the classification of new employees.

ARTICLE 9 - UNION SECURITY

9.01 All employees who come under this Agreement shall maintain membership in Local 636.

9.02 A new employee shall become a member of Local 636 as follows:

Probationary and temporary employees, after the satisfactory completion of their probationary period under Article 7.01 shall become regular employees and shall come under all Articles of this Agreement.

It is mutually understood and agreed upon that probationary employees may be dismissed for reasons less serious than those affecting full-time employees. Such causes shall include, but may not be limited to, matters pertaining to performance and the ability to get along with others. The Steward will be notified on dismissal.

9.03 The City agrees to deduct, each *pay*, from the wages of all employees in the Bargaining Unit, including Probationary and Temporary Employees, Union dues as directed by the Union from time to time. The City also agrees to deduct and remit an amount equivalent to the Union initiation fee from each new employee upon the successful completion of their probationary period.

The Union shall notify the City, in writing, of the amount of such dues to be deducted under this section and, provide at least thirty (30) days written notice of any changes in the amounts thereof that may be directed from time to time.

The City shall forward these deductions to the Union once each month, together with an alphabetical listing of names showing:

a) the amount deducted from each employee;

b) the total amount of dues deducted to date from each individual employee;

c) all information used to determine this deduction
- including but not limited to: the employee's regular hourly rate;
gross weekly earnings and; overtime.

Such remittances will be forwarded to the Union so that they are received not later than the fifteenth (15^{th}) day of the month following the month in which the dues have been deducted.

Payroll deductions will not include any fines. Union dues will be included on the employee's T4 slip (for income tax purposes).

In consideration of the deduction and forwarding of Union dues by the City, the Union agrees to indemnify and save harmless the City against any claim or liability arising out of, or resulting from, the collection and forwarding of regular Union dues or Union initiation fees.

9.04 (A) When a Union Officer is away on Union business, the Corporation will pay the wages and related benefits. The Corporation will bill the Union for the cost at no administrative charge to the Union.

(B) Additional time off requested (to an aggregate total maximum of 3 days annually) for other Union members away on Union business will be at the discretion of the operating department and if approved, the Corporation will pay the wages and related benefits. The Corporation will bill the Union for the cost and a 10% administrative charge to the union.

ARTICLE 10 - SCHEDULE OF WAGE RATES

10.01 The Corporation agrees to pay and the Union agrees to accept for the term of this Agreement the Schedule of Hourly Wage Rates attached hereto as Schedule 1.

10.02 Probationary and temporary employees will be paid in accordance with Schedule 1 of this Agreement and in accordance with the terms of the Employment Standards Act.

ARTICLE 11 - HOURS OF WORK AND OVERTIME

11.01 **(a)** The hours of work for all employees except Purchasing & Stores Division will be 8:00 a.m. to 4:00 p.m., five (5) days a week, Monday to Friday during which a twenty (20) minute paid lunch will be allowed. Normally this will be at a natural job break and on the job site. Employees in transit from job site to job site will be allowed to stop at designated areas. Designated areas may include employee's home, restaurants, service centre or other areas mutually agreeable to the employee affected and their supervisor.

(b) The standard work week for Purchasing & Stores Employees in the Purchasing & Stores Division shall consist of five (5), eight (8) hour shifts per week Monday through Friday. Shifts generally shall be 7:00 a.m. to 3:00 p.m., 8:00 a.m. to 4:00 p.m., and 9:00 a.m. to 5:00 p.m. daily or as revised from time to time by mutual consent.

(c) Authorized work performed in excess of employee's standard work day shall be paid at the rate of time and one half of the employee's regular rate for the first hour and double the employee's rate for all additional hours until relieved. The relief period shall consist of an absence of eight (8) hours from the job, except under extenuating circumstances where the relief period may be less than eight

(8) hours when mutually agreed upon by the employee concerned and the Corporation.

(d) Employees will have the option of banking up to a maximum 40 hours in lieu of overtime (at the applicable OT rates) per year to be taken in each calendar year, which if not taken will be paid out at the end of each year. (i.e 2 hours OT worked equals 4 hours lieu time at double time)

11.02 Authorized overtime performed by any employee on a Saturday will be paid at the rate of time and one half the employee's regular rate for the first hour and double the employee's regular rate for hours worked after the first hour.

11.03 Authorized overtime work performed by any employee on Sunday shall be paid at the rate of double the regular hourly rate.

11.04 Authorized overtime work performed on a Paid Holiday by an employee shall be paid at the rate of double the regular hourly rate in addition to any Paid Holiday pay to which the employee may be entitled.

11.05 The Corporation will offer overtime, planned or unplanned, to all competent employees normally doing the work, beginning with the employee who has the least overtime for the year to date, through to the employee who has the most, until the required staffing is met. If an employee is missed they will be granted the next overtime opportunity. The list of employees will be updated weekly.

11.06 Employees required to work four (4) hours or more overtime before the start of their shift may take equivalent time off without pay sometime during that regular shift.

ARTICLE 12 - STANDBY DUTY

12.01 Due to the extraordinary responsibilities of the Corporation to maintain service affecting the public welfare, all employees shall be prepared to render service in other than normal working hours at applicable prevailing rates of pay for emergencies and qualified and eligible employees must take their turn as standby for trouble duty as indicated by the standby roster.

12.02 The current requirements for standby duty are as follows:

(a) BRANTFORD POWER DEPARTMENT

(i) OPERATIONS DIVISION – Lineperson

~~Class A & B Linepersons, Leadhand or Sub-Foreperson shall be assigned in turn~~ from a roster for standby duty as required. For each weekend, at least one (1) Class A Lineperson or Class B Lineperson, Leadhand or Sub-foreperson shall be assigned as first call and at least one (1) Class A Lineperson, Leadhand or Sub-Foreperson or Class B Lineperson shall be assigned as second call for standby duty for each weekend and on each Paid Holiday. Class B Linepersons cannot be assigned first and second call on the same weekend.

Employees assigned for standby duty for the week shall also be assigned standby duty on a Paid Holiday if it occurs during the period from 4:00 p.m. the Friday immediately preceding the assigned week until 8:00 a.m. the Friday immediately following the assigned week. Should a Statutory Holiday occur on a Friday, the standby assignment shall commence on the Thursday at 4:00 p.m. prior to.

(a) eligible employees must take a minimum of **4 standby** week coverages.

(b) All eligible employees shall be allowed to trade their on-call on a one for one basis. The employee will notify the supervisor of any changes.

(c) Employees "on call" are expected to respond and to be present at the job site within (30) thirty minutes of receiving notification advising them of a problem, following posted speed limits and traffic signals and signs.

(d) Any employee who wishes to take the minimum on-call turns of **(4) four** can give any extras to other eligible on-call employee. If no one wishes to take this on-call coverage then the individual who originally had it will be obligated to take it. The employee will notify the supervisor of any change by two days prior to the scheduled on-call.

(e) Any on-call turn that an employee cannot take due to sickness or bereavement the pin system will be used.

(f) While an employee is on-call there will be no trading during that time unless the supervisor on call has approved the change.

(g) No employee shall take more than three (3) consecutive standby weeks.

(II) Customer Premise Servicepersons and Meter Technicians

(a) Customer Premise Servicepersons may be called out to work other than pre-arranged hours for service work on ground level reconnects and domestic electric water heaters. At least one (1) Customer Premises Serviceperson shall be assigned for weekend standby duty. Any evening work undertaken after 9:00 p.m. must be approved by the Supervisor. Employees assigned for standby duty for the weekend shall also be assigned standby duty on a Paid Holiday if it occurs during the period from 4:00 p.m. the Friday immediately preceding the assigned week until 8:00 a.m. the Friday immediately following the assigned week. Should a Statutory Holiday occur on a Friday, the standby assignment shall commence on the Thursday at 4:00 p.m. prior to.

(b) ~~Customer Premise Servicepersons and Meter Technicians "on call" are~~ expected to respond and to be present at the job site within (30) thirty minutes of receiving notification advising them of a problem, following posted speed limits and traffic signals and signs.

12.03 The hours of work and rates of pay for standby duty shall be as follows:

Regular working day - from 4:00 p.m. until the following morning at 8:00 a.m. – effective **May 30th, 2010 – one dollar and thirty-five cents ($1.35)** per hour.

Weekend - from 4:00 p.m. Friday to 8:00 a.m. Monday – effective **May 30th, 2010 – one dollar and thirty-five cents ($1.35)** per hour.

Paid Holiday - from 8:00 a.m. in the morning to 8:00 a.m. the following morning – effective **May 30th, 2010 – one dollar and thirty-five cents ($1.35)** per hour, plus time and one half for the hours worked between 8:00 a.m. to 4:00 p.m.. Double time shall apply at all other hours. Minimum call-out shall pay two (2) hours at the applicable overtime rate. Minimum call-out shall apply only to the first call out occurring within the two (2) hour period.

An employee shall be allowed one day off when assigned to standby on a Paid Holiday.

12.04 Employees other than those assigned to standby duty in Clause 12.02 when required for standby duty shall be paid at the rate and conditions of Clause 12.03.

12.05 The Corporation will provide and pay for a pocket paging device for an employee when the employee is performing on standby duty.

12.06 The hours specified in this article for standby duty may be changed by mutual consent of the Corporation and the employees concerned.

ARTICLE 13 - OVERTIME

13.01 All overtime exceeding four (4) hours, planned twenty-four (24) hours in advance, shall be treated as a normal workday with the exception that the time will be paid at appropriate overtime rates.

ARTICLE 14 - TEMPORARY TRANSFERS AND REASSIGNMENTS

14.01 Whenever a group of three (3) employees are required to perform construction or maintenance work on plant without continuous supervision for two (2) hours or more, one (1) employee shall be assigned as a Leadhand and shall be paid the Leadhand rate in Schedule 1 of their department. Pre-approved by Foreman

Whenever a group of four (4) or more employees are required to perform construction or maintenance work on plant without continuous supervision for two (2) hours or more, one (1) employee shall be assigned as a Sub-Foreperson and shall be paid the Sub-Foreperson rate in Schedule 1 of their department. Pre-approved by Foreman

ARTICLE 15 - CALL TIME

15.01 Employees who are called out for work shall be paid the minimum of two (2) hours at applicable overtime rates for such call outs, for which payment two (2) hours work may be required. Elapsed time between calls eligible for minimum call out shall be more than two (2) hours.

15.02 No overtime payment shall be made during scheduled working hours.

15.03 When employees are called out for work less than two (2) hours before regular working hours, regular overtime rates will apply, with no minimum.

ARTICLE 16 - MEAL ALLOWANCE

16.01 Employees required to work one (1) hour or more before their normal starting time shall be allowed **an eight ($8.00)** dollar meal on Corporation time and such time is not to exceed thirty (30) minutes.

All other employees required to work four (4) hours or more continuous overtime shall be entitled to a meal of value twelve ($12.00) dollars on Corporation time for each four (4) hours worked and such time is not to exceed thirty (30) minutes

ARTICLE 17 - PAID HOLIDAYS

17.01 All employees who have completed ninety (90) days' of their probationary period shall be paid eight (8) hours for the following Paid Holidays: New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Thanksgiving Day, half day before Christmas Day, Christmas Day, Boxing Day, and half day before New Year's Day, plus a floating day which may be taken at a time mutually agreed by the employee and supervisor.

17.02 Whenever any of the above Paid Holidays falls on Saturday or Sunday, it shall be observed on the following Monday, unless a day is set aside by Government or Local Order, or as mutually agreed.

17.03 Employees required to work on Paid Holidays, with the exception of those indicated in 12.02 and 17.04 will be paid for all such hours worked at the rate of double time, which payment shall be in addition to any holiday pay to which the employee may be entitled.

17.04 In order to receive payment for a Paid Holiday, it will be necessary for an employee to be present on the working day preceding said holiday and the working day immediately following, except where permission is obtained to the contrary or where sickness occurs.

17.05 If one of the above Paid Holidays falls on a week day included in an employee's annual vacation period, then another vacation day with pay shall be allowed. This other vacation day with pay shall be determined by the Corporation at the employee's request.

ARTICLE 18 – VACATIONS

18.01 **Employees hired between January 1st and June 30 shall be entitled to one (1) day of vacation with pay at the employee's regular hourly rate for each complete month of service between the employee's start date and December 31 of the first vacation year to a maximum of ten (10) days.**

Employees hired after June 30th shall be entitled to no vacation in that first year but to be paid at four (4) percent of their annual gross earnings effective December 31.

Employees on the active payroll with one (1) full year's continuous service shall be entitled to two (2) weeks vacation with pay in the year in which the one (1) year of service is completed and thereafter.

Employees on the active payroll with four (4) years continuous service shall be entitled to three (3) weeks vacation with pay in the year in which the four (4) years service is completed and thereafter.

Employees on the active payroll with ten (10) years continuous service shall be entitled to four (4) weeks vacation with pay in the year in which the ten (10) years service is completed and thereafter.

Employees on the active payroll with sixteen (16) years continuous service shall be entitled to five (5) weeks vacation with pay in the year in which the sixteen (16) years service is completed and thereafter.

Employees on the active payroll with twenty-five (25) years continuous service shall be entitled to six (6) weeks vacation with pay in the year in which the twenty-five (25) years service is completed and thereafter.

18.02 The vacation period for each employee shall be determined by sign-up, seniority to prevail. The holiday sign-up shall be posted and completed by March 31 in each year in each department and shall be approved by the Supervisor by April 7. Vacations prior to March 31 shall receive approval from the Supervisor.

18.03 No vacations will be allowed which interfere with the Corporation's satisfactory maintenance of its services to the public in all departments and the Corporation shall be the sole judge of the number of employees and the classifications that shall be allowed holidays at any one period. Every effort will be made by the Management and Corporation to provide vacations to the convenience of the employees.

18.04 When an employee takes vacation between November 15 and December 31, or between January 1 and April 1, the employee shall be entitled to one (1) additional day's pay, or one (1) additional Paid Holiday, per week of vacation taken during the above-mentioned periods. The additional Paid Holiday shall be taken consecutively with the vacation in question.

18.06 An employee whose employment is terminated prior to completing one (1) year or more of continuous employment shall receive four (4%) per cent of the employee's earnings for the period worked, in lieu of vacation. An employee whose employment is terminated after the employee has completed one (1) year or more of continuous employment and who has not had their vacation, shall receive a percentage of their earnings for the period worked, in lieu of such vacation, as follows: four (4%) per cent if eligible for two (2) weeks' vacation; six (6%) per cent if eligible for three (3) weeks' vacation; eight (8%) per cent if eligible for four (4) weeks' vacation; ten (10%) per cent if eligible for five (5) weeks' vacation; twelve (12%) per cent if eligible for six (6) weeks' vacation.

18.07 Accumulated Paid Holidays will be used before vacations except between November 15 and December 31 and between January 1 and April 1.

18.08 All vacations earned for any given calendar year shall be used by the employees no later than January 31 of the following year.

Any such vacations taken during the month of January of the following year shall be paid at the appropriate rate of pay in effect in December of the vacation calendar year.

In cases of extended leave requirements for foreign travel, etc., an employee may request in writing to the Director of Human Resources a carry over vacations from one vacation year to the next. Such holdback will be subject to the same rate of pay requirements specified in the previous paragraph.

ARTICLE 19 - HEALTH INSURANCE

~~**19.01** The Corporation agrees to provide the Manulife Benefit Plan as follows:~~

a) **Manulife Life** Semi-Private Hospital Plan,

b) **Manulife Life** Drug Prescription Plan (.35¢ deductible);

c) **Manulife** Dental Plan No. 7 and Rider 1 covering root canal, with the 2010 O.D.A. Schedule of Rates effective January 1, 2010; **Effective January 1, 2011 – a (1) one year lag in the ODA Schedule of rates**; Orthodontic coverage at 50% co-insurance for dependant children to a lifetime maximum of $1500)

d) **Manulife** Vision Care plan to a maximum of **$250.00 per two year period and effective June 1, 2010 an employee may use the vision coverage towards laser eye surgery and employees will be covered for eye exams to a maximum of $85 every two years; Effective June 1, 2011 Vision Care plan increases to a maximum of $275 per two year period and Effective June 1, 2012 Vision Care plan increases to a maximum of $300 per two year period.**

e) **Manulife** Massage Therapy 100% coverage to$500.00/year,

f) **Manulife** coverage for Chiropractor: 100% coverage for 1st $500.00 50% coverage in excess of $500.00 to maximum of $1000.00;

g) **Manulife coverage for Physiotherapy 100% coverage to $500.00/year effective June 1, 2010;**

h) **Manulife** Extended Health Care Plan (deductible $10 single/$20 family);

i) **Manulife** Deluxe Travel Plan for all employees who have completed ninety (90) days of their probationary period.

It is understood that the employees' portion of the E.I. rebate will be used to provide for the ODA Schedule and additional benefits (dental only) as agreed to in this contract.

The Corporation may substitute a plan underwritten by a carrier other than **Manulife** provided such a plan provides similar or better coverage. The permission of the Union is required **but will not be unreasonably withheld.**

19.02 In the case of retirement due to total and permanent disability not covered by the Workplace Safety & Insurance Board, after a minimum of twenty (20) years' service with the Corporation and after the age of 55 years, the Corporation agrees to pay 100 per cent of the cost of the Liberty Mutual Extended Health Care Plan, the Liberty Mutual Dental Plan No. 7 and Rider 1 covering root canal at the ODA fee schedule in effect at the time of retirement.

19.03 In the case of retirement prior to age 65 if the employee is eligible for early retirement under the OMERS pension plan, the Corporation agrees to provide a Special Retirees Benefit Plan (with any co-payment of premiums in effect prior to retirement, paid by the retiree), until the employee reaches age 65. Should the employee die prior to age 65 and while in receipt of these health benefits the employee's spouse shall continue to receive the benefits (with any co-payment of premiums in effect paid by the retired employee's spouse), until the date at which the employee would have been 65 years of age or until remarriage of the spouse, whichever is sooner.

19.04 The employees' portion of the EI rebate shall be used to provide the ODA schedule as set out in 19.01. In the event that the EI rebate is no longer available, it is agreed that the ODA schedule shall be reduced by the employees' portion. The Corporation agrees that the reduction will not be more than one year from the year currently in force.

19.05 The employer shall pay 100% of premium cost to provide to all full time employees who have completed three (3) months of service and are on the active payroll, basic life insurance coverage in the amount of two (2) times their regular earnings, the amount to be rounded to the closest one thousand dollars ($1,000) until the employee reaches the age of 65 or retires, whichever comes first. Optional Group Life Insurance for employees will be made available with the employee paying the premiums and subject to the carrier's limitations.

Note: New Life Insurance coverage to be effective the 1st of the month following a signed agreement.

ARTICLE 20 - SICK AND ACCIDENT BENEFIT

20.01 Any employee who has completed ninety (90) days of the employee's probationary period and is in the active employ of the Corporation shall be credited with one and one half (1 ½) days of sick pay for each month of service with the Corporation for the duration of this agreement. The number of days or parts of days for which the employee received "sick pay" allowance shall be deducted from the employee's cumulative sick pay credits.

20.02 Upon retirement, death, or termination of those employees hired prior to December 31, 1981, and after ten (10) years' continuous employment with the Power and Stores Departments, an employee shall be entitled to receive an amount equal to one half (½) the number of days accumulated under the provisions of Article 20.01, to be up to a maximum number of days which will not exceed the least of one hundred and thirty-one (131) days or the number of days standing to the employee's credit at December 31, 1981, to be paid at the employee's regular hourly rate in effect on December 31, 1981, for an eight (8) hour day.

Upon retirement, death, or termination of those employees hired prior to December 31, 1981, and after five (5) years' continuous employment with the Power and Stores Departments, an employee shall be entitled to receive an amount equal to one-quarter of the number of days accumulated under the provisions of Article 20.01, to be up to a maximum number of days standing to the employee's credit at December 31, 1981, to be paid at the employee's regular hourly rate in effect on December 31, 1981, for an eight (8) hour day.

20.03 For each day that an employee is absent due to sickness, one day's pay shall be paid when available and deducted from the employee's accumulated sick pay credits in the following order: (a) from credits accumulated after January 1, 1982, and when those are exhausted, (b) from vested credits accumulated before December 31, 1981. Any credits so deducted may be replaced at a later date by the accumulation of further invested credits to a maximum of the credits previously accumulated to December 31, 1981.

The first day of the third occasion, and the first day of each occasion of sickness thereafter within a calendar year, for which occasion no doctor's certificate is presented, will not be paid nor deducted from the employee's accumulated sick pay credits. Doctor, dentist or Compensation appointments do not count as occasions unless they require an employee absence of two (2) hours or more. For a series of such appointments for previously arranged therapy, the employee must provide their supervisor with a certified list of appointments. Wherever possible, the employee shall try to arrange appointments at the beginning or end of their work day.

20.04 During the period that an employee of the Corporation is receiving payment from the employee's sick pay credits, the Corporation may at its own discretion have an employee examined by the Corporation's physician. Employees who have been absent from work due to accident or sickness for a period longer than five (5) working days shall be required to produce a medical certificate proving physical fitness to return to work.

20.05 This sick leave plan is not applicable when the disability of the employee comes under the provision of the Workplace Safety and Insurance Board.

20.06 When the Corporation receives sufficient, appropriate medical documentation regarding an employee's inability to work due to a work related injury, they will continue the employee's regular pay and subsequent WSIB payments will be directed to the City. The "top up" portion of the regular pay will be deducted on a pro-rata basis from the employee's sick leave accumulation and if the sick leave accumulation declines to zero then the top up ceases.

If the employee fails to co-operate with the Corporation then the Corporation has the right to suspend the regular pay provided as above and provide only the "top up" (as outlined above) and only after the employee is in receipt of Workplace Safety and Insurance Benefits" as per the Collective Agreement.

20.07 An employee due for retirement shall be allowed to take a leave of absence with pay equal to one-half of the employee's accumulated sick leave not to exceed 131 days prior to the employee's retirement date. Effective January 1, 1982, an employee due for retirement shall be allowed to take a leave of absence with pay equal to the value of the employee's accumulated vesting of Article 20.02 prior to the employee's retirement date.

20.08 The Corporation agrees to a Long Term Disability Plan for all full-time IBEW employees, to be 90% paid by the Corporation. The LTD will be based on 70% of the employee's base rate, up to a maximum of $3,000.00 per month.

20.09 In accordance with the requirements of Human Resources Development Canada for EI Premium Reduction, and for the purpose of clarification of the current sick leave plan afforded all full-time employees of the Corporation, the following is mutually understood: Payment of benefits can only cease on the date of layoff or separation where the disability started within the two months preceding this date, and that notice of layoff or separation was given prior to the beginning of the disability. In all other situations relating to layoff or separation, benefits must be paid for the lesser of the duration of the disability, the utilization of all accumulated sick days, or 15 weeks.

ARTICLE 21 - PENSIONS

21.01 All employees at the start of their probationary period shall make application for inclusion in the Ontario Municipal Employee Retirement System pension plans, and at the completion of ninety (90) days' of their probationary period, the life insurance plan.

21.02 Employees who qualify will be eligible for early retirement under the Ontario Municipal Employee Retirement System's "90 Plan".

Any employee wishing to retire under either plan must indicate their irrevocable intention in writing to the Human Resources Department no later than two months (2) before the retirement date. The General Manager has the right to accept or reject postponement of the retirement date if later requested by the employee.

ARTICLE 22 - BEREAVEMENT LEAVE

22.01 The Corporation shall grant upon request of an employee a leave of absence of three (3) consecutive working days without loss of pay, upon the death of a member of his/her immediate family for the purpose of mourning. When there has been a delay in the burial, if required and requested by an employee, an additional day shall be granted for the purpose of attending the burial. Immediate family shall mean the following: husband/wife, son, son-in-law, daughter, daughter-in-law, mother, step-mother, mother-in-law, father, step-father, father-in-law, sister, brother, grandchild.

22.02 In the case of death of other members of the employee's family (grandmother, grandfather, aunt, uncle, sister-in-law, brother-in-law, or spouse's grandparents), employees shall be granted leave of absence with pay to compensate for time lost, not to exceed one (1) day, to attend the funeral.

22.03 On request and at the Department Head/Director's discretion, employees shall be allowed time off with pay while serving as pallbearer at a funeral.

22.04 All payments for bereavement leave shall be subject to the approval of the Manager and will be conditional upon the employee attending the funeral.

22.05 Bereavement under Clause 22.01, which occurs during an employee's paid vacation, may replace the paid vacation for the duration of the bereavement leave subject to the approval of the Manager.

ARTICLE 23 - LEAVE OF ABSENCE

23.01 Leave of absence may be granted for legitimate personal reasons (which shall include leave of absence for two delegates on Union business not to exceed twenty-one (21) days in any year for each) on written request to the Corporation. It is understood that any leave of absence is subject to reasonable notice being given to the Corporation. In the event any such leave of absence is not used for the purpose granted, the employee is subject to dismissal. Leave of absence will not be granted nor extended beyond a period of three (3) months and it is understood that no leave of absence will be considered by the Corporation which interferes with regular operation or which requires the performance of additional overtime work.

23.02 The Corporation's share of all payments of any nature ordinarily made on the employee's behalf will cease during the period of any leave of absence, except as specifically provided in this agreement. This clause shall not apply to Union delegates on leave of absence as provided in 23.01.

23.03 The Corporation agrees to reimburse employees for loss of pay less court stipend for appearance for jury duty or subpoenaed as a witness. If any employee is dismissed by the bench in the course of normal working hours, the employee shall report for duty within one hour to their supervisor. Failure to do so will result in the assessment of the absence as "leave of absence without pay".

ARTICLE 24 - EXTREME WEATHER CONDITIONS

24.01 Employees will not be required to perform their regular duties during extreme weather conditions unless an emergency exists. When employees are pulled off the job by the supervisor due to extreme weather conditions they shall be assigned other duties as required. No time shall be lost through adverse weather conditions.

ARTICLE 25 - UNIFORMS AND PROTECTIVE CLOTHING

25.01 (A) METERING AND CUSTOMER SERVICE DIVISION

The Meter Installer and the Customer Premise Servicepersons shall be supplied with wash and wear uniforms as required. The Meter Technicians will also be given uniforms similar to the Customer Service employees.

Uniformed employees will be responsible for keeping their uniforms in a clean and tidy manner.

Rainwear, including rubber boots, pants, hats, coveralls and gloves shall be supplied where required, by the Corporation.

Such equipment and uniforms to be supplied on an as required basis or to a schedule as set out by the Corporation.

(B) OPERATIONS DIVISION AND STORES

An allowance of $300.00 will be provided to each full-time Operations Division employee and $150.00 to each full-time Stores Division employee in the first week of each calendar year.

Effective January 1, 2005 - the allowance for full-time Operations Division employees changes to a credit of $500.00 each in the first week of each calendar year and the Corporation will supply up to 5 Long sleeves (Fire Retardant) orange blaze shirts, or equivalent annually to each full-time Operations Division employee .

This allowance/credit is for the purchase of safety/rubber boots, rainwear, orange blaze coveralls, coats, jackets, shirts and any other orange blaze clothing, and hard hat liners. The purchase of such merchandise is the responsibility of the employee.

Note: Leather gloves and hard hats shall be supplied where required by the employer.

25.02 The Corporation agrees to pay a safety boot reimbursement as follows:

The Corporation will provide on an annual basis between January 1st and **September 1st** a reimbursement, upon presentation of a receipt, towards the purchase of Canadian Standards Association (C.S.A.) approved footwear up to the following limits denoted below:

Effective January 1, 2011, One Hundred and Fifty ($150.00) Dollars, (including all taxes);

Effective January 1, 2012, One Hundred and Fifty-five ($155.00) Dollars, (including all taxes);

Effective January 1, 2013, One Hundred and Sixty ($160.00) Dollars, (including all taxes).

25.03 The Corporation will assume the cost of safety lenses for employees who are required to wear prescription glasses.

ARTICLE 26 - DRIVING TESTS

26.01 The Corporation will assume the cost of medical and driver test for employees that require an appropriate valid Ontario Driver's License as part of their employment. If necessary to be taken during regular working hours, scheduling of time off with pay for driver's test will be granted at the discretion of the department supervisor.

ARTICLE 27 - TOOLS AND EQUIPMENT

27.01 All authorized tools required to do the work shall be supplied by the Corporation.

ARTICLE 28 - SAFETY

28.01 The parties to this Agreement shall establish a Health and Safety Committee comprising of two (2) members appointed by the Corporation and two (2) members appointed by the Union. The Committee shall meet once every three (3) months, unless the Committee agrees otherwise.

28.02 No employee is required to use defective equipment, or commit any act that the employee considers unsafe, but is required to immediately report to the Foreperson/Manager any such defective equipment. All Corporation equipment that becomes defective will be replaced by the Corporation and remain the property of the Corporation. Safety meetings shall be held at least once each month in the Brantford Power Department on Corporation time. The time of the meeting shall be at the discretion of the Director of Operations.

28.03 When employees are working on live equipment, all Linepersons shall use rubber gloves in accordance with EUSA ground to ground rules. Gloves shall be sent for test at least every two months. Rubber gloves shall be air tested by each Lineperson before using. The Foreperson or Sub-Foreperson shall supervise. Not less than two Linepersons and/or Underground Station Technicians, one of whom shall be a Class A Tradesperson and the other may be either a Class A or Class B Tradesperson, shall be assigned to work on high voltage, with the exception of fused switches, air or oil switches or breakers that can be operated from the ground by switch stick, or permanently installed operating mechanism. In the case of these executions, one

Lineperson or Underground Station Technician shall be considered competent and safe to operate alone. Two employees shall be assigned to work in underground vaults when opening and closing cutouts and disconnects.

28.04 The safety practices as issued by the Electrical and Utilities Safety Association of Ontario and approved by the Corporation and approved by Local 636, International Brotherhood of Electrical Workers and the Labour Legislation of the Province of Ontario shall be the minimum safety standards.

ARTICLE 29 - PROGRESSION SCHEDULES

29.01 Progression in all classifications shall be on an annual basis providing successful completion of all training required at each level is obtained.

29.02 If an employee fails to make satisfactory progress, the employee's advancement will be withheld. When progression is withheld, management shall give notice to the employee and include the reasons for withholding progression.

The employee's general performance including educational attainment will be reviewed from time to time, and at such time as the employee has corrected the deficiency and is found satisfactory, normal progression will be resumed.

If progression would have been withheld due to circumstances outside the Management and employee's control, then advancement will normally be allowed subject to the employee subsequently achieving the necessary requirements. Failure to do so will result in a return to the previous classification.

ARTICLE 30 - DURATION

30.01 This Agreement shall be effective from **June 1, 2010 to May 31, 2013** and, unless changed by mutual consent, the terms of this agreement shall continue automatically thereafter for an annual period of one year each, unless either party notifies the other in writing within the period of ninety (90) days immediately prior to the expiration date, that it desires to amend the agreement.

30.02 Negotiations shall begin within thirty (30) days following notification for amendment as provided in the preceding paragraph.

30.03 If, pursuant to such negotiations, an agreement is not reached on the renewal or amendment of this agreement, or the making of a new agreement prior to the current expiry date, this agreement shall continue in full force and effect until a new agreement is signed between the Parties or until conciliation proceedings prescribed under the Ontario Labour Relations Act, 1970, or current version, have been completed, whichever date should first occur.

IN WITNESS WHEREOF each of the parties has caused this Agreement to be signed by their duly authorized officials or representatives of this 30, day of September, 2010.

The Corporation of the City of Brantford	**I.B.E.W. Local 636 Unit 45**
Mike Hancock, Mayor	D. Murdaca, Business Representative
Darryl Lee, City Clerk	M. Sitarski, Unit Chair
	Ryan Hantz, Negotiation Team
	Chris Tanz, Negotiation Team
	Patricia Johnson, Negotiation Team

SCHEDULE 1

Classification Rates of Pay – Brantford Power Department

Classification		30-May-2010	29-May-2011	03-June-2012
Lineperson				
Journeyman (complete 4th yr) **		$33.009	$33.779	$34.565
Apprentice Class A (48 mo. +) 90%		$29.708	$30.401	$31.109
Apprentice Class B (36-48 mo.) 80%		$26.407	$27.023	$27.652
Apprentice Class C (24-36 mo.) 70%		$23.106	$23.645	$24.196
Apprentice Class D (12-24 mo.) 60%		$19.805	$20.267	$20.739
Apprentice (1st year) 50%		$16.505	$16.890	$17.283
Leadhand, Lineperson				
(6.5% of Lineperson rate)		$35.155	$35.975	$36.812
Sub-Foreperson (Line)				
(9% of Lineperson rate)		$35.980	$36.819	$37.676
Meter Technician				
Level 4 – Journeyperson (100%)		$33.009	$33.779	$34.565
Trainee – Level 3 (90%)		$29.708	$30.401	$31.109
Trainee – Level 2 (80%)		$26.407	$27.023	$27.739
Trainee – Level 1 (70%)		$23.106	$23.645	$24.196

SCHEDULE 1

Classification Rates of Pay – Brantford Power Department Continued

Classification		30-May-2010	29-May-2011	3-June-2012
Line Truck Driver & Grounds person				
3rd Year & Above		$28.029	$28.590	$29.162
2nd Year		$25.788	$26.304	$26.830
Trainee - 2nd 6 Months		$22.512	$22.962	$23.421
Trainee - 1st 6 Months		$21.403	$21.831	$22.268
Customer Service Premise Person/Collections				
3rd Year & Above		$28.614	$29.186	$29.770
2nd Year		$25.899	$26.417	$26.945
Trainee - 2nd 6 Months		$24.120	$24.602	$25.094
Trainee - 1st 6 Months		$21.403	$21.831	$22.268
Labourer				
3rd Year & Above		$15.423	$15.731	$16.046
2nd Year		$14.791	$15.087	$15.389
After 1 Year		$14.231	$14.516	$14.806
2nd 6 Months		$13.660	$13.933	$14.212
1st 6 Months		$13.098	$13.360	$13.627

SCHEDULE 1

Classification Rates of Pay – Brantford Power Department Continued

Classification Rates of Pay – Purchasing & Stores Division

Classification		30-May-2010	29-May-2011	03-June-2012
Material Handler				
3rd Year & Above		$28.614	$29.186	$29.770
2nd Year		$25.899	$26.417	$26.945
Trainee - 2nd 6 Months		$24.120	$24.602	$25.094
Trainee - 1st 6 Months		$21.403	$21.831	$22.268
Dispatcher and Locates				
3rd Year & Above		$28.029	$28.590	$29.162
2nd Year		$25.788	$26.304	$26.830
Trainee - 2nd 6 Months		$22.512	$22.962	$23.421
Trainee - 1st 6 Months		$21.403	$21.831	$22.268
Assistant Material Handler				
3rd Year & Above		$25.899	$26.417	$26.945
2nd Year		$24.120	$24.602	$25.094
Trainee - 2nd 6 Months		$22.512	$22.962	$23.421
Trainee - 1st 6 Months		$21.403	$21.831	$22.268

BRANTFORD

Letter of Understanding

Between

The Corporation of the City of Brantford

And

The International Brotherhood of Electrical Workers

Local 636, Power Unit 45

Re: Rest Periods

The Corporation of the City of Brantford and The International Brotherhood of Electrical Workers, Local 636, Power Unit 45, agree that:

1) A major consideration in extensive overtime work is the well being and safety of employees.

2) Employees called in to respond to emergency work and working six (6) hours or more between 9 p.m. and 8 a.m. preceding a regular scheduled shift, will be entitled to an eight (8) hour rest period prior to the start of their next shift, up to four (4) hours of which will be paid time off.

3) At the discretion of management, employees may have the option to utilize available time off or time worked between 9 p.m. and 8 a.m. in accordance with prevailing overtime rates to make up the balance of the remaining eight (8) hour rest period.

4) Minimum call-outs do not apply. The above is for worked time only.

5) Planned overtime is not included for paid rest periods.

6) The on-call supervisor must be notified after working four (4) continuous hours responding to emergency work between 9 p.m. and 8 a.m. preceding a regular scheduled shift.

Dated this 30 day of September, in Brantford, Ontario

For City of Brantford

A. Szaloky,
(Acting) Dir. Human Resources

J. Loucks,
Chief Operating Officer - BPI

I. Murchie,
Director of Operations

T. Fischer,
Human Resources

R. Boutette,
Human Resources

For Union

D. Murdaca (Business Manager)

M. Sitarski, Unit Chair

Ryan Hantz, Negotiation Team

Chris Tanz, Negotiation Team

Patricia Johnson, Negotiation Team

Letter of Understanding

Between

The Corporation of the City of Brantford

And

The International Brotherhood of Electrical Workers

Local 636, Power Unit 45

Re: Assistant Material Handler coverage for Dispatcher and Locates

The Corporation of the City of Brantford and The International Brotherhood of Electrical Workers, Local 636, Power Unit 45, agree that:

1. The Assistant Material Handler when assigned to the Dispatcher and Locates classification, shall be paid no less than the rate he/she is presently receiving and

2. The Assistant Material Handler shall receive the higher of his/her own level or the equivalent level for the Dispatcher and Locates job to which he/she is assigned a full (8) eight hour shift. This provision shall not include relief during breaks and lunch periods.

Dated this 30 day of September, 2010 in Brantford, Ontario

For City of Brantford	For Union
A. Szaloky, (Acting) Dir. Human Resources	D. Murdaca (Business Manager)
J. Loucks, Chief Operating Officer - BPI	M. Sitarski, Unit Chair
L Murchie, Director of Operations	Ryan Hantz, Negotiation Team
T. Fischer, Human Resources	Chris Tanz, Negotiation Team
R. Boutette, Human Resources	Patricia Johnson, Negotiation Team

Collective Agreement

Between

Brantford Power Inc.

And

The International Brotherhood Of Electrical Workers Local 636, Unit 45

June 1st, 2013 to May 31st, 2016

Index

Index

THIS AGREEMENT entered into at Brantford, Ontario, this 9th day of October 2013

between

BRANTFORD POWER INC.

(Hereinafter referred to as the "Corporation")

OF THE FIRST PART

and

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL 636, UNIT 45

(Hereinafter referred to as the "Union")

OF THE SECOND PART

ARTICLE 1 - RECOGNITION AND COVERAGE

1.01 The Corporation recognizes the Union as the exclusive collective bargaining agent for all its employees within the **Lines Department (including Metering and Customer Services) and Dispatch & Stores**, save and except non-working forepersons, persons above the rank of non-working foreperson and all administrative staff, office staff, **student hired throughout the summer months and co-op students hired during their work terms and those excluded under the Ontario Labour Relations Act and those represented by another trade union.**

ARTICLE 2 - MANAGEMENT FUNCTIONS

2.01 The Union acknowledges that it is exclusively the function of the Corporation to:

(a) Maintain order, discipline and efficiency;

(b) Hire, discharge, direct, promote, demote, lay off and suspend or otherwise discipline employees subject to the provisions of this agreement provided that a claim of discriminatory promotion, demotion or layoff, or that an employee has been unjustly discharged or disciplined, may be treated as a grievance procedure;

(c) Maintain and enforce rules and regulations to be observed by the employees;

(d) Generally to manage the operations and undertakings of the Corporation and, without restricting the generality of the foregoing, to determine the methods, procedures, machinery and equipment to be used, the schedules and programming of projects and to exercise all other customary functions of management.

2.02 The Corporation agrees that these functions will be exercised in a manner consistent with the provisions of this agreement.

ARTICLE 3 - RELATIONSHIP

3.01 The Corporation and the Union agree that there will be no discrimination exercised or practiced by either of them or their representatives or members because of an employee's membership or non-membership in the Union.

3.02 The Corporation agrees to give three (3) months' written notice to the Union of any planned technological change that may result in the reduction of the Union's work forces.

3.03 In the event of technological change that may result in employees being placed in a different job classification, or displaced due to lack of work, such employees will be given preferential consideration to be trained in new skills or new jobs, provided such employees have the qualifications for such training and provided such job opportunities exist.

3.04 All communications relating to matters arising out of this Agreement shall be addressed and delivered to the Business Representative of the Union, and his/her designate. All communications required by this Article shall be copied to the unit Chairperson.

3.05 The two parties to this Agreement shall establish a Labour Management Committee of four (4) members, with two (2) members from each side, which shall meet quarterly or at other times that may be mutually agreed upon.

ARTICLE 4 - GRIEVANCE PROCEDURE

4.01 Any difference concerning the interpretation, application, administration or alleged violation of the provisions of this Agreement, except with respect to the discharge of a Probationary Employee, shall be dealt with in the following manner:

STEP 1

1. A Regular Employee wishing to present a grievance shall submit the grievance in writing to the Immediate Supervisor, indicating the nature of the grievance and the remedy sought within ten (10) working days after the occurrence of the circumstances giving rise to it. The Immediate Supervisor shall reply within three (3) working days after having received the grievance.

STEP 2

2. If the reply of the Supervisor is not satisfactory to the Employee concerned, the written grievance shall be referred to the Director/Department Head within five (5) working days after the reply of the Immediate Supervisor. The

Director/Department Head shall meet with the Employee and members or designates of the Grievance Committee of the Union within five (5) working days to discuss the grievance. A reply to the grievance shall be given in writing within five (5) working days after the meeting has been held at this stage of the grievance procedure.

3. Any of the time allowances provided in (1) and (2) of this Article may be extended by mutual agreement between the parties concerned.

4. If a grievance is to be referred to arbitration, it shall be so referred within twenty (20) working days after the date of the reply referred to in Item 2 above.

5. In the event of a group grievance, a policy grievance or a grievance respecting the discharge or suspension of a Regular Employee, the grievance shall be in writing, indicating the nature of the grievance and the remedy sought. The grievance will be processed commencing at Step 2 Director/Department Head of the grievance procedure. This clause shall not be used for the purpose of abridging the right of the Employee to process grievances, nor shall it be used for the purpose of submitting matters to be handled through the grievance procedure by Employees.

6. The Grievance Committee shall consist of the Steward, the Grievor, and the Unit Chairperson or his/her designate, and the Area Representative, who will meet at Step 2 of the Grievance Procedure.

7. If either the Union or the Corporation claims there has been a violation or misinterpretation of the terms of this Agreement by the other party, it may state such claim in writing, which will be processed as a grievance commencing at Stage Two of the grievance procedure.

8. All steps of the grievance procedure, including any meetings with a Grievance Mediation Officer, shall be held during regular hours of work, with no loss of regular wages.

4.02 The Corporation will recognize a Negotiating Committee of not more than four (4) employees to represent the Union in meetings with the Corporation in negotiation of this Agreement. The Corporation will pay the employees for any normal working time lost at such meetings, up to but not including conciliation. The Union Negotiating Committee shall be accompanied by the Local Union Business Representative and/or a Representative of the International Brotherhood of Electrical Workers at any meeting. There will be a maximum of two (2) employees from the line department unless it is operationally feasible whereby the maximum will not apply.

It is understood that Union Committee members and stewards have their regular duties to perform on behalf of the Corporation and that these will normally take pre-eminence. However, if it is necessary for a committee member or steward to attend Union business or investigate a grievance during working hours they shall not leave their workplace without first obtaining permission from their supervisor. Such permission shall not be unreasonably denied.

4.03 All decisions arrived at between the representative of the Corporation and of the Union shall be final and binding upon the Corporation, the Union, and the employee or employees concerned.

4.04 Saturdays, Sundays and paid holidays as defined in Article 17, will not be counted in determining the time within which any action is to be taken or completed in each of the steps of the grievance procedure or under Article 5.

4.05 Failure of the grievor or the Union to process a grievance procedure within the time limit specified shall not be deemed to have prejudiced the Union on any similar grievance.

4.06 An employee shall have the right to request Union representation at any formal interview with management.

4.07 A letter of reprimand or suspension will be removed from the record of an employee twenty-four (24) months following the receipt of such letter or suspension provided that the employee's record has been discipline free for a twenty-four (24) month period.

ARTICLE 5 – ARBITRATION

5.01 Where a difference arises as to interpretation, application, or administration of this Agreement, including any question as to whether a matter is arbitrable, or where an allegation is made that this agreement has been violated, either of the parties, may after exhausting any grievance procedure established by this agreement, notify the other Party in writing not later than (20) working days after the expiration of the time limits defined under Step No. 2, of its desire to submit the difference or allegation to arbitration. When either party to this agreement requests that a grievance be submitted to arbitration, it shall make such request in writing - Correspondence on this matter will be addressed to the Unit Chair of the IBEW Local 636 Unit 45 with a copy to the Business Manager, and the Human Resources Director for the Corporation. Within five (5) working days thereafter, the party receiving the request will appoint a nominee. The two (2) nominees will attempt to select, by agreement, a third person, who will act as Chairman of the Arbitration Board.

5.02 If the party receiving the request for arbitration fails to appoint a nominee within five (5) working days, or the two nominees fail to agree on a third person to act as Chairman, the matter will be referred to the Ontario Labour Relations Board, which shall be requested to make the necessary appointments.

5.03 The grievance may be submitted to a single Arbitrator, if the parties mutually agree, as provided through the Ontario Labour Relations Board.

5.04 Notwithstanding the provisions for an Arbitration Board, either party may request the Minister to refer any grievance to a single arbitrator to be appointed by the Minister in accordance with the Ontario Labour Relations Act (Section 49), as amended.

5.05 No person may be appointed who has been involved in any attempt to settle the grievance being arbitrated.

5.06 Except by mutual agreement between the parties to this Agreement, no matter may be submitted to arbitration which has not been properly carried through the grievance procedure.

5.07 The Arbitrator or Arbitration Board shall not be authorized to render any decision inconsistent with the terms of this Agreement, nor shall they alter, modify, add to or amend any of its provisions.

5.08 The proceedings will be expedited by the parties to this Agreement. A unanimous or majority decision will be final and binding upon both the Corporation and the Union but, in the case of a Board, should a majority decision not be given, then the decision of the chairman will be final and binding.

5.09 Each of the parties hereto shall bear the expenses of the nominee it appoints, and the parties shall jointly bear the expenses, if any, of the Chairman or the Board or the single Arbitrator.

5.10 Wherever arbitration Board is referred to in the Agreement, the parties may mutually agree to appoint a single arbitrator.

ARTICLE 6 - NO-STRIKE AND NO-LOCKOUT

6.01 The Union agrees that there shall be no strike (as defined in the Ontario Labour Relations Act) and the Corporation agrees that there shall be no lockout (as defined in the Ontario Labour Relations Act).

ARTICLE 7 – SENIORITY

7.01 During the first 6 months of employment, all employees shall be considered on probation. Any absences from work totaling more than 10 working days in the 6 month period will extend the probationary period by an equivalent number of working days. After completion of the probationary period, the employee's name shall then be credited with 6 months seniority. For the purpose of this Article, there shall be a separate **Lines Department (including Metering, and Customer Service), and Dispatch and Stores** seniority list.

7.02 When making lay-offs and recalls of employees, departmental seniority shall apply, providing the employee has the necessary qualifications and ability to perform the work available.

7.03 Any permanent employee covered by the bargaining unit who is promoted to a position outside of the bargaining unit shall retain their seniority for a period of twelve (12) months. Employees returning to their former classifications from outside of the bargaining unit shall be granted their seniority for up to six (6) months when being reclassified back into the bargaining unit.

7.04 Employees shall lose all seniority and will no longer be employees of the Corporation if they:

(a) Voluntarily quit the employ of the Corporation;

(b) Are discharged for cause, unless reversed through the grievance procedure;

(c) Are laid off for a period of more than **eighteen (18)** months, or are laid off for a period of one (1) month with seniority of less than one (1) year (accumulative), temporary labour to be excluded.

(d)(i) Fail to report for work within ten (10) days after being notified by registered mail sent to the last address registered with the Corporation to return to work following a lay-off;

(ii) Fail to notify the Human Resources Department within three (3) days after receipt of such notice of their intention to report for work;

(iii) Fail to report for work for three (3) days without leave of absence or without notifying their immediate supervisor. If the immediate supervisor is unavailable, another supervisor in the work unit may be notified. If the employee is too ill to telephone, the employee's spouse or other close relative may notify the appropriate supervisor;

(e) Are still absent from duty due to illness or non compensable injury after twenty-four (24) months of being on Long Term Disability, or when declared totally disabled by the Insurance Company, whichever is the earlier of the two.

7.05 It shall be the duty of employees to notify the Human Resources Department promptly in writing of any change of their address. If an employee shall fail to do this, the Corporation will not be responsible for failure of a notice to reach employee's address.

ARTICLE 8 - VACANCIES AND CLASSIFICATION

8.01 Vacancies existing, or new bargaining unit jobs created in the **Lines Department (including Metering and Customer Service) and Dispatch & Stores**, shall be posted on the bulletin boards for seven (7) working days. Written applications from employees shall be filed with the Corporation within nine (9) calendar days of posting. Where applicants are equally qualified for the opening, the applicant with the greatest seniority shall be given preference.

8.02 The Corporation agrees that the Human Resources Department will consult with the Unit Chairperson prior to making the appointment to a new position, or a new classification, or where a reclassification is involved, and will notify the Business Representative of the Union of the classification of new employees.

ARTICLE 9 - UNION SECURITY

9.01 All employees who come under this Agreement shall maintain membership in Local 636.

9.02 A new employee shall become a member of Local 636 as follows:

Probationary and temporary employees, after the satisfactory completion of their probationary period under Article 7.01 shall become regular employees and shall come under all Articles of this Agreement.

It is mutually understood and agreed upon that probationary employees may be dismissed for reasons less serious than those affecting full-time employees. Such causes shall include, but may not be limited to, matters pertaining to performance and the ability to get along with others. The Steward will be notified on dismissal.

9.03 The **Corporation** agrees to deduct, each *pay*, from the wages of all employees in the Bargaining Unit, including Probationary and Temporary Employees, Union dues as directed by the Union from time to time. The Corporation also agrees to deduct and remit an amount equivalent to the Union initiation fee from each new employee upon the successful completion of their probationary period.

The Union shall notify the Corporation, in writing, of the amount of such dues to be deducted under this section and, provide at least thirty (30) days written notice of any changes in the amounts thereof that may be directed from time to time.

The **Corporation** shall forward these deductions to the Union once each month, together with an alphabetical listing of names showing:

a) the amount deducted from each employee;

b) the total amount of dues deducted to date from each individual employee;

c) all information used to determine this deduction
- including but not limited to: the employee's regular hourly rate;
gross weekly earnings and; overtime.

Such remittances will be forwarded to the Union so that they are received not later than the fifteenth (15^{th}) day of the month following the month in which the dues have been deducted.

Payroll deductions will not include any fines. Union dues will be included on the employee's T4 slip (for income tax purposes).

In consideration of the deduction and forwarding of Union dues by the Corporation, the Union agrees to indemnify and save harmless the Corporation against any claim or liability arising out of, or resulting from, the collection and forwarding of regular Union dues or Union initiation fees.

9.04 (A) When a Union Officer is away on Union business, the Corporation will pay the wages and related benefits. The Corporation will bill the Union for the cost at no administrative charge to the Union.

(B) Additional time off requested (to an aggregate total maximum of 3 days annually) for other Union members away on Union business will be at the discretion of the operating department and if approved, the Corporation will pay the wages and related benefits. The Corporation will bill the Union for the cost and a 10% administrative charge to the union.

ARTICLE 10 - SCHEDULE OF WAGE RATES

10.01 The Corporation agrees to pay and the Union agrees to accept for the term of this Agreement the Schedule of Hourly Wage Rates attached hereto as Schedule 1.

10.02 Probationary and temporary employees will be paid in accordance with Schedule 1 of this Agreement and in accordance with the terms of the Employment Standards Act.

ARTICLE 11 - HOURS OF WORK AND OVERTIME

11.01 **(a)** The hours of work for all employees except **Dispatch & Stores** will be 8:00 a.m. to 4:00 p.m., five (5) days a week, Monday to Friday during which a twenty (20) minute paid lunch will be allowed. Normally this will be at a natural job break and on the job site. Employees in transit from job site to job site will be allowed to stop at designated areas. Designated areas may include employee's home, restaurants, service centre or other areas mutually agreeable to the employee affected and their supervisor.

(b) The standard work week for **Dispatch & Stores** Employees shall consist of five (5), eight (8) hour shifts per week Monday through Friday during which a twenty (20) minute paid lunch will be allowed. Shifts generally shall be 8:00 a.m. to 4:00 p.m. daily or as revised from time to time by mutual consent.

(c) Authorized work performed in excess of employee's standard work day shall be paid at the rate of time and one half of the employee's regular rate for the first hour and double the employee's rate for all additional hours until relieved. The relief period shall consist of an absence of eight (8) hours from the job, except under extenuating circumstances where the relief period may be less than eight (8) hours when mutually agreed upon by the employee concerned and the Corporation.

(d) Employees will have the option of banking up to a maximum 40 hours in lieu of overtime (at the applicable OT rates) per year to be taken in each calendar year, which if not taken will be paid out at the end of each year. (i.e 2 hours OT worked equals 4 hours lieu time at double time) **Effective January 1, 2014 – banking up to a maximum of 48 hours.**

11.02 Authorized overtime performed by any employee on a Saturday will be paid at the rate of time and one half the employee's regular rate for the first hour and double the employee's regular rate for hours worked after the first hour.

11.03 Authorized overtime work performed by any employee on Sunday shall be paid at the rate of double the regular hourly rate.

11.04 Authorized overtime work performed on a Paid Holiday by an employee shall be paid at the rate of double the regular hourly rate in addition to any Paid Holiday pay to which the employee may be entitled.

11.05 The Corporation will offer overtime, planned or unplanned, to all competent employees normally doing the work, beginning with the employee who has the least overtime for the year to date, through to the employee who has the most, until the required staffing is met. If an employee is missed they will be granted the next overtime opportunity. The list of employees will be updated weekly.

11.06 Employees required to work four (4) hours or more overtime before the start of their shift may take equivalent time off without pay sometime during that regular shift.

ARTICLE 12 - STANDBY DUTY

12.01 Due to the extraordinary responsibilities of the Corporation to maintain service affecting the public welfare, all employees shall be prepared to render service in other than normal working hours at applicable prevailing rates of pay for emergencies and qualified and eligible employees must take their turn as standby for trouble duty as indicated by the standby roster.

12.02 The current requirements for standby duty are as follows:

(a) **BRANTFORD POWER DEPARTMENT**

(i) <u>LINEPERSON</u>

Class A & B Linepersons, Leadhand or Sub-Foreperson shall be assigned in turn from a roster for standby duty as required. For each weekend, at least one (1) Class A Lineperson or Class B Lineperson, Leadhand or Sub-foreperson shall be assigned as first call and at least one (1) Class A Lineperson, Leadhand or Sub-Foreperson or Class B Lineperson shall be assigned as second call for standby duty for each weekend and on each Paid Holiday. Class B Linepersons cannot be assigned first and second call on the same weekend.

Employees assigned for standby duty for the week shall also be assigned standby duty on a Paid Holiday if it occurs during the period from 4:00 p.m. the Friday immediately preceding the assigned week until 8:00 a.m. the Friday immediately following the assigned week. Should a Statutory Holiday occur on a Friday, the standby assignment shall commence on the Thursday at 4:00 p.m. prior to.

(a) eligible employees must take a minimum of **(3) three standby** week coverages.

(b) All eligible employees shall be allowed to trade their on-call on a one for one basis. The employee will notify the supervisor of any changes.

(c) Employees "on call" are expected to respond and to be present at the job site within (30) thirty minutes of receiving notification advising them of a problem, following posted speed limits and traffic signals and signs.

(d) Any employee who wishes to take the minimum on-call turns of **three (3)** can give any extras to other eligible on-call employee. If no one wishes to take this on-call coverage then the individual who originally had it will be obligated to take it. The employee will notify the supervisor of any change by two days prior to the scheduled on-call.

(e) Any on-call turn that an employee cannot take due to sickness or bereavement the pin system will be used.

(f) While an employee is on-call there will be no trading during that time unless the supervisor on call has approved the change.

(g) No employee shall take more than three (3) consecutive standby weeks.

(II) Customer Premise Servicepersons and Meter Technicians

(a) Customer Premise Servicepersons may be called out to work other than pre-arranged hours for service work on ground level reconnects and domestic electric water heaters. At least one (1) Customer Premises Serviceperson shall be assigned for weekend standby duty. Any evening work undertaken after 9:00 p.m. must be approved by the Supervisor. Employees assigned for standby duty for the weekend shall also be assigned standby duty on a Paid Holiday if it occurs during the period from 4:00 p.m. the Friday immediately preceding the assigned week until 8:00 a.m. the Friday immediately following the assigned week. Should a Statutory Holiday occur on a Friday, the standby assignment shall commence on the Thursday at 4:00 p.m. prior to.

(b) Customer Premise Servicepersons and Meter Technicians "on call" are expected to respond and to be present at the job site within (30) thirty minutes of receiving notification advising them of a problem, following posted speed limits and traffic signals and signs.

12.03 The hours of work and rates of pay for standby duty shall be as follows:

Regular working day - from 4:00 p.m. until the following morning at 8:00 a.m. – effective May 30th, 2010 – one dollar and thirty-five cents ($1.35) per hour.

Weekend - from 4:00 p.m. Friday to 8:00 a.m. Monday – effective May 30th, 2010 – one dollar and thirty-five cents ($1.35) per hour.

Paid Holiday - from 8:00 a.m. in the morning to 8:00 a.m. the following morning – effective May 30th, 2010 – one dollar and thirty-five cents ($1.35) per hour, plus time and one half for the hours worked between 8:00 a.m. to 4:00 p.m.. Double time shall apply at all other hours. Minimum call-out shall pay two (2) hours at the applicable overtime rate. Minimum call-out shall apply only to the first call out occurring within the two (2) hour period.

An employee shall be allowed one day off when assigned to standby on a Paid Holiday.

12.04 Employees other than those assigned to standby duty in Clause 12.02 when required for standby duty shall be paid at the rate and conditions of Clause 12.03.

12.05 The Corporation will provide and pay for a pocket paging device **and/or a cellular phone** for an employee when the employee is performing on standby duty.

12.06 The hours specified in this article for standby duty may be changed by mutual consent of the Corporation and the employees concerned.

ARTICLE 13 - OVERTIME

13.01 All overtime exceeding four (4) hours, planned twenty-four (24) hours in advance, shall be treated as a normal workday with the exception that the time will be paid at appropriate overtime rates.

ARTICLE 14 - TEMPORARY TRANSFERS AND REASSIGNMENTS

14.01 Whenever a group of three (3) employees are required to perform construction or maintenance work on plant without continuous supervision for two (2) hours or more, one (1) employee shall be assigned as a Leadhand and shall be paid the Leadhand rate in Schedule 1 of their department. Pre-approved by Foreman

Whenever a group of four (4) or more employees are required to perform construction or maintenance work on plant without continuous supervision for two (2) hours or more, one (1) employee shall be assigned as a Sub-Foreperson and shall be paid the Sub-Foreperson rate in Schedule 1 of their department. Pre-approved by Foreman

ARTICLE 15 - CALL TIME

15.01 Employees who are called out for work shall be paid the minimum of two (2) hours at applicable overtime rates for such call outs, for which payment two (2) hours work may be required. Elapsed time between calls eligible for minimum call out shall be more than two (2) hours.

15.02 No overtime payment shall be made during scheduled working hours.

15.03 When employees are called out for work less than two (2) hours before regular working hours, regular overtime rates will apply, with no minimum.

ARTICLE 16 - MEAL ALLOWANCE

16.01 Employees required to work one (1) hour or more before their normal starting time shall be allowed an eight ($8.00) dollar meal on Corporation time and such time is not to exceed thirty (30) minutes.

All other employees required to work four (4) hours or more continuous overtime shall be entitled to a meal of value twelve ($12.00) dollars on Corporation time for each four (4) hours worked and such time is not to exceed thirty (30) minutes

ARTICLE 17 - PAID HOLIDAYS

17.01 All employees who have completed ninety (90) days' of their probationary period shall be paid eight (8) hours for the following Paid Holidays: New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Thanksgiving Day, half day before Christmas Day, Christmas Day, Boxing Day, and half day before New Year's Day, plus a floating day which may be taken at a time mutually agreed by the employee and supervisor.

17.02 Whenever any of the above Paid Holidays falls on Saturday or Sunday, it shall be observed on the following Monday, unless a day is set aside by Government or Local Order, or as mutually agreed.

17.03 Employees required to work on Paid Holidays, with the exception of those indicated in 12.02 and 17.04 will be paid for all such hours worked at the rate of double time, which payment shall be in addition to any holiday pay to which the employee may be entitled.

17.04 In order to receive payment for a Paid Holiday, it will be necessary for an employee to be present on the working day preceding said holiday and the working day immediately following, except where permission is obtained to the contrary or where sickness occurs.

17.05 If one of the above Paid Holidays falls on a week day included in an employee's annual vacation period, then another vacation day with pay shall be allowed. This other vacation day with pay shall be determined by the Corporation at the employee's request.

ARTICLE 18 – VACATIONS

18.01 Employees hired between January 1st and June 30 shall be entitled to one (1) day of vacation with pay at the employee's regular hourly rate for each complete month of service between the employee's start date and December 31 of the first vacation year to a maximum of ten (10) days.

Employees hired after June 30th shall be entitled to no vacation in that first year but to be paid at four (4) percent of their annual gross earnings effective December 31.

Employees on the active payroll with one (1) full year's continuous service shall be entitled to two (2) weeks vacation with pay in the year in which the one (1) year of service is completed and thereafter.

Employees on the active payroll with four (4) years continuous service shall be entitled to three (3) weeks vacation with pay in the year in which the four (4) years service is completed and thereafter.

Employees on the active payroll with ten (10) years continuous service shall be entitled to four (4) weeks vacation with pay in the year in which the ten (10) years service is completed and thereafter.

Employees on the active payroll with sixteen (16) years continuous service shall be entitled to five (5) weeks vacation with pay in the year in which the sixteen (16) years service is completed and thereafter.

Employees on the active payroll with twenty-five (25) years continuous service shall be entitled to six (6) weeks vacation with pay in the year in which the twenty-five (25) years service is completed and thereafter.

18.02 The vacation period for each employee shall be determined by sign-up, seniority to prevail. The holiday sign-up shall be posted and completed by March 31 in each year in each department and shall be approved by the Supervisor by April 7. Vacations prior to March 31 shall **be determined by a sign-up sheet by November 1st of the previous year with seniority prevailing upon** approval from the Supervisor.

18.03 No vacations will be allowed which interfere with the Corporation's satisfactory maintenance of its services to the public in all departments and the Corporation shall be the sole judge of the number of employees and the classifications that shall be allowed holidays at any one period. Every effort will be made by the Management and Corporation to provide vacations to the convenience of the employees.

18.04 When an employee takes vacation between November 15 and December 31, or between January 1 and April 1, the employee shall be entitled to one (1) additional day's pay, or one (1) additional Paid Holiday, per week of vacation taken during the above-mentioned periods. The additional Paid Holiday shall be taken consecutively with the vacation in question.

18.06 An employee whose employment is terminated prior to completing one (1) year or more of continuous employment shall receive four (4%) per cent of the employee's earnings for the period worked, in lieu of vacation. An employee whose employment is terminated after the employee has completed one (1) year or more of continuous employment and who has not had their vacation, shall receive a percentage of their earnings for the period worked, in lieu of such vacation, as follows: four (4%) per cent if eligible for two (2) weeks' vacation; six (6%) per cent if eligible for three (3) weeks' vacation; eight (8%) per cent if eligible for four (4) weeks' vacation; ten (10%) per cent if eligible for five (5) weeks' vacation; twelve (12%) per cent if eligible for six (6) weeks' vacation.

18.07 Accumulated Paid Holidays will be used before vacations except between November 15 and December 31 and between January 1 and April 1.

18.08 All vacations earned for any given calendar year shall be used by the employees no later than January 31 of the following year.

Any such vacations taken during the month of January of the following year shall be paid at the appropriate rate of pay in effect in December of the vacation calendar year.

In cases of extended leave requirements for foreign travel, etc., an employee may request in writing to the Director of Human Resources a carry over vacations from one vacation year to the next. Such holdback will be subject to the same rate of pay requirements specified in the previous paragraph.

ARTICLE 19 - HEALTH INSURANCE

19.01 The Corporation agrees to provide the Manulife Benefit Plan as follows:

- **a)** Manulife Life Semi-Private Hospital Plan,
- **b)** Manulife Life Drug Prescription Plan (.35¢ deductible);
- **c)** Manulife Dental Plan No. 7 and Rider 1 covering root canal, Orthodontic coverage at 50% co-insurance for dependant children to a lifetime maximum of $1500) **and with – a (1) one year lag in the ODA Schedule of rates in each year of the contract;**
- **d)** Manulife Vision Care plan to a maximum of $250.00 per two year period and effective June 1, 2010 an employee may use the vision coverage towards laser eye

surgery and employees will be covered for eye exams to a maximum of $85 every two years; Effective June 1, 2011 Vision Care plan increases to a maximum of $275 per two year period and Effective June 1, 2012 Vision Care plan increases to a maximum of $300 per two year period.

e) Manulife Massage Therapy 100% coverage to$500.00/year,

f) Manulife coverage for Chiropractor: 100% coverage for 1st $500.00 50% coverage in excess of $500.00 to maximum of $1000.00;

g) Manulife coverage for Physiotherapy 100% coverage to $500.00/year effective June 1, 2010;

h) Manulife Extended Health Care Plan (deductible $10 single/$20 family);

i) Manulife Deluxe Travel Plan for all employees who have completed ninety (90) days of their probationary period.

It is understood that the employees' portion of the E.I. rebate will be used to provide for the ODA Schedule and additional benefits (dental only) as agreed to in this contract.

The Corporation may substitute a plan underwritten by a carrier other than Manulife provided such a plan provides similar or better coverage. The permission of the Union is required but will not be unreasonably withheld.

19.02 In the case of retirement due to total and permanent disability not covered by the Workplace Safety & Insurance Board, after a minimum of twenty (20) years' service with the Corporation and after the age of 55 years, the Corporation agrees to pay 100 per cent of the cost of the Liberty Mutual Extended Health Care Plan, the Liberty Mutual Dental Plan No. 7 and Rider 1 covering root canal at the ODA fee schedule in effect at the time of retirement.

19.03 In the case of retirement prior to age 65 if the employee is eligible for early retirement under the OMERS pension plan, the Corporation agrees to provide a Special Retirees Benefit Plan (with any co-payment of premiums in effect prior to retirement, paid by the retiree), until the employee reaches age 65. Should the employee die prior to age 65 and while in receipt of these health benefits the employee's spouse shall continue to receive the benefits (with any co-payment of premiums in effect paid by the retired employee's spouse), until the date at which the employee would have been 65 years of age or until remarriage of the spouse, whichever is sooner.

19.04 The employees' portion of the EI rebate shall be used to provide the ODA schedule as set out in 19.01. In the event that the EI rebate is no longer available, it is agreed that the ODA schedule shall be reduced by the employees' portion. The Corporation agrees that the reduction will not be more than one year from the year currently in force.

19.05 The employer shall pay 100% of premium cost to provide to all full time employees who have completed three (3) months of service and are on the active payroll, basic life insurance coverage in the amount of two (2) times their regular earnings, the amount to be rounded to the closest one thousand dollars ($1,000) until the employee reaches the age of 65 or retires, whichever comes first. Optional Group Life Insurance for employees will be made available with the employee paying the premiums and subject to the carrier's limitations.

Note: New Life Insurance coverage to be effective the 1st of the month following a signed agreement.

ARTICLE 20 - SICK AND ACCIDENT BENEFIT

20.01 Any employee who has completed ninety (90) days of the employee's probationary period and is in the active employ of the Corporation shall be credited with one and one half (1 ½) days of sick pay for each month of service with the Corporation for the duration of this agreement. The number of days or parts of days for which the employee received "sick pay" allowance shall be deducted from the employee's cumulative sick pay credits.

20.02 Upon retirement, death, or termination of those employees hired prior to December 31, 1981, and after ten (10) years' continuous employment with the **Lines Department (including Metering and Customer Services) and Dispatch & Stores**, an employee shall be entitled to receive an amount equal to one half (½) the number of days accumulated under the provisions of Article 20.01, to be up to a maximum number of days which will not exceed the least of one hundred and thirty-one (131) days or the number of days standing to the employee's credit at December 31, 1981, to be paid at the employee's regular hourly rate in effect on December 31, 1981, for an eight (8) hour day.

Upon retirement, death, or termination of those employees hired prior to December 31, 1981, and after five (5) years' continuous employment with the **Lines Department (including Metering and Customer Services) and Dispatch & Stores**, an employee shall be entitled to receive an amount equal to one-quarter of the number of days accumulated under the provisions of Article 20.01, to be up to a maximum number of days standing to the employee's credit at December 31, 1981, to be paid at the employee's regular hourly rate in effect on December 31, 1981, for an eight (8) hour day.

20.03 For each day that an employee is absent due to sickness, one day's pay shall be paid when available and deducted from the employee's accumulated sick pay credits in the following order: (a) from credits accumulated after January 1, 1982, and when those are exhausted, (b) from vested credits accumulated before December 31, 1981. Any credits so deducted may be replaced at a later date by the accumulation of further invested credits to a maximum of the credits previously accumulated to December 31, 1981.

The first day of the third occasion, and the first day of each occasion of sickness thereafter within a calendar year, for which occasion no doctor's certificate is presented, will not be paid nor deducted from the employee's accumulated sick pay credits. Doctor, dentist or Compensation appointments do not count as occasions unless they require an employee absence of two (2) hours or more. For a series of such appointments for previously arranged therapy, the employee must provide their supervisor with a certified list of appointments. Wherever possible, the employee shall try to arrange appointments at the beginning or end of their work day.

20.04 During the period that an employee of the Corporation is receiving payment from the employee's sick pay credits, the Corporation may at its own discretion have an employee examined by the Corporation's physician. Employees who have been absent from work due to accident or sickness for a period longer than five (5) working days shall be required to produce a medical certificate proving physical fitness to return to work.

20.05 This sick leave plan is not applicable when the disability of the employee comes under the provision of the Workplace Safety and Insurance Board.

20.06 When the Corporation receives sufficient, appropriate medical documentation regarding an employee's inability to work due to a work related injury, they will continue the employee's regular pay and subsequent WSIB payments will be directed to the **Corporation**. The "top up" portion of the regular pay will be deducted on a pro-rata basis from the employee's sick leave accumulation and if the sick leave accumulation declines to zero then the top up ceases.

If the employee fails to co-operate with the Corporation then the Corporation has the right to suspend the regular pay provided as above and provide only the "top up" (as outlined above) and only after the employee is in receipt of Workplace Safety and Insurance Benefits" as per the Collective Agreement.

20.07 An employee due for retirement shall be allowed to take a leave of absence with pay equal to one-half of the employee's accumulated sick leave not to exceed 131 days prior to the employee's retirement date. Effective January 1, 1982, an employee due for retirement shall be allowed to take a leave of absence with pay equal to the value of the employee's accumulated vesting of Article 20.02 prior to the employee's retirement date.

20.08 The Corporation agrees to a Long Term Disability Plan for all full-time IBEW employees, to be 90% paid by the Corporation. The LTD will be based on 70% of the employee's base rate, up to a maximum of $3,000.00 per month.

20.09 In accordance with the requirements of Human Resources Development Canada for EI Premium Reduction, and for the purpose of clarification of the current sick leave plan afforded all full-time employees of the Corporation, the following is mutually understood: Payment of benefits can only cease on the date of layoff or separation where the disability started within the two months preceding this date, and that notice of layoff or separation was given prior to the beginning of the disability. In all other situations relating to layoff or separation, benefits must be paid for the lesser of the duration of the disability, the utilization of all accumulated sick days, or 15 weeks.

ARTICLE 21 - PENSIONS

21.01 All employees at the start of their probationary period shall make application for inclusion in the Ontario Municipal Employee Retirement System pension plans, and at the completion of ninety (90) days' of their probationary period, the life insurance plan.

21.02 Employees who qualify will be eligible for early retirement under the Ontario Municipal Employee Retirement System's "90 Plan".

Any employee wishing to retire under either plan must indicate their irrevocable intention in writing to the Human Resources Department no later than two months (2) before the retirement date. The **CEO of Brantford Power Inc**. has the right to accept or reject postponement of the retirement date if later requested by the employee.

ARTICLE 22 - BEREAVEMENT LEAVE

22.01 **The Corporation shall grant upon request of an employee a leave of absence of five (5) consecutive working days without loss of pay, upon the death of a member of his/her immediate family for the purpose of mourning.** The Corporation shall grant upon request of an employee a leave of absence of three (3) consecutive working days without loss of pay, upon the death of a member of his/her **extended** family for the purpose of mourning. When there has been a delay in the burial, if required and requested by an employee, an additional day shall be granted for the purpose of attending the burial. Immediate family shall mean the following: husband/wife, son, daughter, mother, step-mother, father, step-father. **Extended family shall mean the following: son in law, daughter in law, mother in law, father in law, sister, brother and grandchild.**

22.02 In the case of death of other members of the employee's family (grandmother, grandfather, aunt, uncle, sister-in-law, brother-in-law, or spouse's grandparents), employees shall be granted leave of absence with pay to compensate for time lost, not to exceed one (1) day, to attend the funeral.

22.03 On request and at the Department Head/Director's discretion, employees shall be allowed time off with pay while serving as pallbearer at a funeral.

22.04 All payments for bereavement leave shall be subject to the approval of the Manager and will be conditional upon the employee attending the funeral.

22.05 Bereavement under Clause 22.01, which occurs during an employee's paid vacation, may replace the paid vacation for the duration of the bereavement leave subject to the approval of the Manager.

ARTICLE 23 - LEAVE OF ABSENCE

23.01 Leave of absence may be granted for legitimate personal reasons (which shall include leave of absence for two delegates on Union business not to exceed twenty-one (21) days in any year for each) on written request to the Corporation. It is understood that any leave of absence is subject to reasonable notice being given to the Corporation. In the event any such leave of absence is not used for the purpose granted, the employee is subject to dismissal. Leave of absence will not be granted nor extended beyond a period of three (3) months and it is understood that no leave of absence will be considered by the Corporation which interferes with regular operation or which requires the performance of additional overtime work.

23.02 The Corporation's share of all payments of any nature ordinarily made on the employee's behalf will cease during the period of any leave of absence, except as specifically provided in this agreement. This clause shall not apply to Union delegates on leave of absence as provided in 23.01.

23.03 The Corporation agrees to reimburse employees for loss of pay less court stipend for appearance for jury duty or subpoenaed as a witness. If any employee is dismissed by the bench in the course of normal working hours, the employee shall report for duty within one hour to their supervisor. Failure to do so will result in the assessment of the absence as "leave of absence without pay".

ARTICLE 24 - EXTREME WEATHER CONDITIONS

24.01 Employees will not be required to perform their regular duties during extreme weather conditions unless an emergency exists. When employees are pulled off the job by the supervisor due to extreme weather conditions they shall be assigned other duties as required. No time shall be lost through adverse weather conditions.

ARTICLE 25 - UNIFORMS AND PROTECTIVE CLOTHING

25.01 **UNIFORM CREDIT**

A credit of $500.00 will be provided to each full-time Operations, **Metering and Customer Service premise** employee, and $150.00 to each full-time Stores employee in the first week of each calendar year.
The Corporation will supply up to 5 Long sleeves (Fire Retardant) orange blaze shirts, or equivalent annually to each full-time Operation's employee .

This credit is for the purchase of safety/rubber boots, rainwear, orange blaze coveralls, coats, jackets, shirts and any other orange blaze clothing, and hard hat liners. The purchase of such merchandise is the responsibility of the employee.

Note: Leather gloves, **Non prescription Safety Glasses(Clear and Tinted)** and hard hats shall be supplied where required by the employer.

25.02 The Corporation agrees to pay a safety boot reimbursement as follows:

The Corporation will provide on an annual basis between January 1st and September 1st a reimbursement, upon presentation of a receipt, towards the purchase of Canadian Standards Association (C.S.A.) approved footwear up to the following limits denoted below:

Effective January 1, 2013, One Hundred and Sixty ($160.00) Dollars, (including all taxes).

25.03 The Corporation will assume the cost of safety lenses for employees who are required to wear prescription glasses.

ARTICLE 26 - DRIVING TESTS

26.01 The Corporation will assume the cost of medical and driver test for employees that require an appropriate valid Ontario Driver's License as part of their employment. If necessary to be taken during regular working hours, scheduling of time off with pay for driver's test will be granted at the discretion of the department supervisor.

ARTICLE 27 - TOOLS AND EQUIPMENT

27.01 All authorized tools required to do the work shall be supplied by the Corporation.

ARTICLE 28 - SAFETY

28.01 The parties to this Agreement shall establish a Health and Safety Committee comprising of two (2) members appointed by the Corporation and two (2) members appointed by the Union. The Committee shall meet once every three (3) months, unless the Committee agrees otherwise.

28.02 No employee is required to use defective equipment, or commit any act that the employee considers unsafe, but is required to immediately report to the Foreperson/Manager any such defective equipment. All Corporation equipment that becomes defective will be replaced by the Corporation and remain the property of the

Corporation. Safety meetings shall be held at least once each month in the Energy and Operations Department on Corporation time. The time of the meeting shall be at the discretion of the Director of Operations.

28.03 When employees are working on live equipment, all Linepersons shall use rubber gloves in accordance with EUSA ground to ground rules. Gloves shall be sent for test at least every two months. Rubber gloves shall be air tested by each Lineperson before using. The Foreperson or Sub-Foreperson shall supervise. Not less than two Linepersons and/or Underground Station Technicians, one of whom shall be a Class A Tradesperson and the other may be either a Class A or Class B Tradesperson, shall be assigned to work on high voltage, with the exception of fused switches, air or oil switches or breakers that can be operated from the ground by switch stick, or permanently installed operating mechanism. In the case of these executions, one Lineperson or Underground Station Technician shall be considered competent and safe to operate alone. Two employees shall be assigned to work in underground vaults when opening and closing cutouts and disconnects.

28.04 The safety practices as issued by the Electrical and Utilities Safety Association of Ontario and approved by the Corporation and approved by Local 636, International Brotherhood of Electrical Workers and the Labour Legislation of the Province of Ontario shall be the minimum safety standards.

ARTICLE 29 - PROGRESSION SCHEDULES

29.01 Progression in all classifications shall be on an annual basis providing successful completion of all training required at each level is obtained.

29.02 If an employee fails to make satisfactory progress, the employee's advancement will be withheld. When progression is withheld, management shall give notice to the employee and include the reasons for withholding progression.

The employee's general performance including educational attainment will be reviewed from time to time, and at such time as the employee has corrected the deficiency and is found satisfactory, normal progression will be resumed.

If progression would have been withheld due to circumstances outside the Management and employee's control, then advancement will normally be allowed subject to the employee subsequently achieving the necessary requirements. Failure to do so will result in a return to the previous classification.

ARTICLE 30 - DURATION

30.01 This Agreement shall be effective from **June 1, 2013 to May 31, 2016** and, unless changed by mutual consent, the terms of this agreement shall continue automatically thereafter for an annual period of one year each, unless either party notifies the other in writing within the period of ninety (90) days immediately prior to the expiration date, that it desires to amend the agreement.

30.02 Negotiations shall begin within thirty (30) days following notification for amendment as provided in the preceding paragraph.

30.03 If, pursuant to such negotiations, an agreement is not reached on the renewal or amendment of this agreement, or the making of a new agreement prior to the current expiry date, this agreement shall continue in full force and effect until a new agreement is signed between the Parties or until conciliation proceedings prescribed under the Ontario Labour Relations Act, 1970, or current version, have been completed, whichever date should first occur.

IN WITNESS WHEREOF each of the parties has caused this Agreement to be signed by their duly authorized officials or representatives of this 9th, day of October, 2013.

Brantford Power Inc.

Paul Kwasnik Chief Executive Officer

Brian D'Amboise, Chief Financial Officer

I.B.E.W. Local 636 Unit 45

D. Murdaca, Business Representative

Mike Sitarski

M. Sitarski, Unit Chair

Ryan Hantz, Negotiation Team

Peter Horvath, Negotiation Team

Patricia Johnson, Negotiation Team

Barry Brown, Business Manager/Financial Secretary

SCHEDULE 1

Classification Rates of Pay – Brantford Power

Classification	03-June-2012	02-June-2013	01-Dec-2013	01-June-2014
Lineperson				
Journeyman (complete 4th yr) **	$34.565	$35.261	$35.614	$36.230
Apprentice Class A (48 mo. +) 90%	$31.109	$31.735	$32.053	$32.607
Apprentice Class B (36-48 mo.) 80%	$27.652	$28.209	$28.491	$28.984
Apprentice Class C (24-36 mo.) 70%	$24.196	$24.683	$24.930	$25.361
Apprentice Class D (12-24 mo.) 60%	$20.739	$21.157	$21.368	$21.738
Apprentice (1st year) 50%	$17.283	$17.631	$17.807	$18.115
Leadhand, Lineperson				
(6.5% of Lineperson rate)	$36.812	$37.553	$37.929	$38.585
Sub-Foreperson (Line)				
(9% of Lineperson rate)	$37.676	$338.434	$38.819	$39.491
Meter Technician				
Level 4 – Journeyperson (100%)	$34.565	$35.261	$35.614	$36.230
Trainee – Level 3 (90%)	$31.109	$31.735	$32.053	$32.607
Trainee – Level 2 (80%)	$27.652	$28.209	$28.491	$28.984
Trainee – Level 1 (70%)	$24.196	$24.683	$24.930	$25.361

SCHEDULE 1

Classification Rates of Pay – Brantford Power Continued

Classification		30-Nov-2014	31-May-2015	29-Nov-2015
Lineperson				
Journeyman (complete 4th yr) **		$36.592	$36.852	$37.221
Apprentice Class A (48 mo. +) 90%		$32.933	$33.167	$33.499
Apprentice Class B (36-48 mo.) 80%		$29.274	$29.482	$29.777
Apprentice Class C (24-36 mo.) 70%		$25.614	$25.796	$26.055
Apprentice Class D (12-24 mo.) 60%		$21.955	$22.111	$22.333
Apprentice (1st year) 50%		$18.296	$18.426	$18.611
Leadhand, Lineperson				
(6.5% of Lineperson rate)		$38.970	$39.247	$39.640
Sub-Foreperson (Line)				
(9% of Lineperson rate)		$39.885	$40.169	$40.571
Meter Technician				
Level 4 – Journeyperson (100%)		$36.592	$36.852	$37.221
Trainee – Level 3 (90%)		$32.933	$33.167	$33.499
Trainee – Level 2 (80%)		$29.274	$29.482	$29.777
Trainee – Level 1 (70%)		$25.614	$25.796	$26.055

SCHEDULE 1

Classification Rates of Pay – Brantford Power Continued

Classification	3-June-2012	02-June-2013	01-Dec-2013	01-June-2014
Line Truck Driver & Grounds person				
3rd Year & Above	$29.162	$29.454	$29.749	$30.046
2nd Year	$26.830	$27.098	$27.369	$27.643
Trainee - 2nd 6 Months	$23.421	$23.655	$23.892	$24.131
Trainee - 1st 6 Months	$22.268	$22.491	$22.716	$22.943
Customer Service Premise Person/Collections				
3rd Year & Above	$29.770	$30.068	$30.369	$30.673
2nd Year	$26.945	$27.214	$27.486	$27.761
Trainee - 2nd 6 Months	$25.094	$25.345	$25.598	$25.854
Trainee - 1st 6 Months	$22.268	$22.491	$22.716	$22.943
Labourer				
3rd Year & Above	$16.046	$16.206	$16.368	$16.532
2nd Year	$15.389	$15.543	$15.698	$15.855
After 1 Year	$14.806	$14.954	$15.104	$15.255
2nd 6 Months	$14.212	$14.354	$14.498	$14.643
1st 6 Months	$13.627	$13.763	$13.901	$14.040

SCHEDULE 1

Classification Rates of Pay – Brantford Power Continued

Classification		30-Nov-2014	31-May-2015	29-Nov-2015
Line Truck Driver & Grounds person				
3rd Year & Above		$30.346	$30.346	$30.649
2nd Year		$27.919	$27.919	$28.198
Trainee - 2nd 6 Months		$24.372	$24.372	$24.616
Trainee - 1st 6 Months		$23.172	$23.172	$23.404
Customer Service Premise Person/Collections				
3rd Year & Above		$30.980	$30.980	$31.290
2nd Year		$28.039	$28.039	$28.319
Trainee - 2nd 6 Months		$26.113	$26.113	$26.374
Trainee - 1st 6 Months		$23.172	$23.172	$23.404
Labourer				
3rd Year & Above		$16.697	$16.697	$16.864
2nd Year		$16.014	$16.014	$16.174
After 1 Year		$15.408	$15.408	$15.562
2nd 6 Months		$14.789	$14.789	$14.937
1st 6 Months		$14.180	$14.180	$14.322

SCHEDULE 1

Classification Rates of Pay – Brantford Power Continued

Classification Rates of Pay – Dispatch & Stores

Classification	03-June-2012	02-June-2013	30-Nov-2013	01-June-2014
Material Handler				
3rd Year & Above	$29.770	$30.068	$30.369	$30.673
2nd Year	$26.945	$27.214	$27.486	$27.761
Trainee - 2nd 6 Months	$25.094	$25.345	$25.598	$25.854
Trainee - 1st 6 Months	$22.268	$22.491	$22.716	$22.943
Dispatcher and Locates				
3rd Year & Above	$29.162	$29.454	$29.749	$30.046
2nd Year	$26.830	$27.367	$27.641	$27.917
Trainee - 2nd 6 Months	$23.421	$23.889	$24.128	$24.369
Trainee - 1st 6 Months	$22.268	$22.713	$22.940	$23.169
Assistant Material Handler				
3rd Year & Above	$26.945	$27.214	$27.486	$27.761
2nd Year	$25.094	$25.345	$25.598	$25.854
Trainee - 2nd 6 Months	$23.421	$23.655	$23.892	$24.131
Trainee - 1st 6 Months	$22.268	$22.491	$22.716	$22.943

Classification Rates of Pay – Dispatch & Stores

Classification		01-Dec-2014	31-May-2015	29-Nov-2015
Material Handler				
3rd Year & Above		$30.980	$30.980	$31.290
2nd Year		$28.039	$28.039	$28.319
Trainee - 2nd 6 Months		$26.113	$26.113	$26.374
Trainee - 1st 6 Months		$23.172	$23.172	$23.404
Dispatcher and Locates				
3rd Year & Above		$30.346	$30.346	$30.649
2nd Year		$28.196	$28.196	$28.478
Trainee - 2nd 6 Months		$24.613	$24.613	$24.859
Trainee - 1st 6 Months		$23.401	$23.401	$23.635
Assistant Material Handler				
3rd Year & Above		$28.039	$28.039	$28.319
2nd Year		$26.113	$26.113	$26.374
Trainee - 2nd 6 Months		$24.372	$24.372	$24.616
Trainee - 1st 6 Months		$23.172	$23.172	$23.404

Letter of Understanding

Between

Brantford Power Inc.

And

The International Brotherhood of Electrical Workers

Local 636, Unit 45

Re: Rest Periods

Brantford Power Inc. and The International Brotherhood of Electrical Workers, Local 636, Power Unit 45, agree that:

1) A major consideration in extensive overtime work is the well being and safety of employees.

2) Employees called in to respond to emergency work and working six (6) hours or more between 9 p.m. and 8 a.m. preceding a regular scheduled shift, will be entitled to an eight (8) hour rest period prior to the start of their next shift, up to four (4) hours of which will be paid time off.

3) At the discretion of management, employees may have the option to utilize available time off or time worked between 9 p.m. and 8 a.m. in accordance with prevailing overtime rates to make up the balance of the remaining eight (8) hour rest period.

4) Minimum call-outs do not apply. The above is for worked time only.

5) Planned overtime is not included for paid rest periods.

6) The on-call supervisor must be notified after working four (4) continuous hours responding to emergency work between 9 p.m. and 8 a.m. preceding a regular scheduled shift.

Dated this 9th day of ~~July~~ Oct. in Brantford, Ontario

For Brantford Power Inc.	For Union
Brian D'Amboise, Chief Financial Officer	D. Murdaca, Business Representative
Mark Simpson, Director, Energy and Operations	M. Sitarski, Unit Chair
Altaf Hussain, Director Engineering and Construction	Ryan Hantz, Negotiation Team
Roland Boutette, HR Representative (Labour Relations)	Peter Horvath, Negotiation Team
	Patricia Johnson, Negotiation Team

Letter of Understanding

Between

Brantford Power Inc.

And

The International Brotherhood of Electrical Workers

Local 636, Unit 45

Re: Assistant Material Handler coverage for Dispatcher and Locates

Brantford Power Inc. and The International Brotherhood of Electrical Workers, Local 636, Power Unit 45, agree that:

1. The Assistant Material Handler when assigned to the Dispatcher and Locates classification, shall be paid no less than the rate he/she is presently receiving and

2. The Assistant Material Handler shall receive the higher of his/her own level or the equivalent level for the Dispatcher and Locates job to which he/she is assigned **a continuous (4) four** hour shift. This provision shall not include relief during breaks and lunch periods.

Dated this 9th day of ~~July~~ Oct, 2013 in Brantford, Ontario

For Brantford Power Inc.

Brian D'Amboise,
Chief Financial Officer

Mark Simpson,
Director, Energy and Operations

Altaf Hussain,
Director Engineering and Construction

Roland Boutette,
HR Representative (Labour Relations)

For Union

D. Murdaca, Business Representative

M. Sitarski, Unit Chair

Ryan Hantz, Negotiation Team

Peter Horvath, Negotiation Team

Patricia Johnson, Negotiation Team

ATTACHMENT N

REFERENCE: 5.0 Energy Probe-26

PROMISSORY NOTE

Due: February 1, 2011

FOR VALUE RECEIVED, Brantford Power Inc. ("the Corporation") hereby promises to pay to or to the order of The Corporation of the City of Brantford (the "City") the principal sum of TWENTY-FOUR MILLION, ONE HUNDRED AND EIGHTY-NINE THOUSAND, ONE HUNDRED AND SIXTY-EIGHT DOLLARS ($24,189,168) (the "Principal Sum") with interest at the rate specified herein on February 1, 2011 (the "Maturity Date"). Interest on the Principal Sum shall accrue from the first day of January, 2004 and be payable at a rate per annum of nine percent (9%) up to and including February 1, 2006, and be payable at a rate per annum of six and one quarter percent (6.25%) thereafter. Interest at the aforesaid rates shall be payable annually to the City on the 30th day after the end of the Corporation's fiscal year.

At the option of the City and with six (6) months prior written notice by the City to the Corporation, this Promissory Note may be extended for successive periods (an "Extension Period") of five (5) years at a rate of interest equal to the prime rate of the Royal Bank of Canada (charged to its customers for commercial loans) plus one and one half percent (1.5%) or such other rate of interest as the City and the Corporation may agree upon (the "Extension Period Rate"). Interest at the Extension Period Rate shall be payable annually to the City on the 30th day after the end of the Corporation's fiscal year.

The obligation of the Corporation to pay the Principal Sum and all interest on this Promissory Note is subordinated and postponed to the obligations of the Corporation from time to time to any other financial institution or lender.

This Promissory Note may, at the option of the City, be converted, as to some or all of the principal sum outstanding, into common shares of the Corporation at a conversion ratio of $100 per share. The foregoing conversion right may be exercised by the City at any time on 90 days prior written notice to the Corporation.

The terms of the Promissory Note are subject to the adjustment provisions of the Transfer By-lay passed by the City on October 23, 2000 as By-law Number 156-2000.

This Promissory Note is not assignable by the City without the consent of the Corporation.

DATED this 19th day of January 2006.

BRANTFORD POWER INC.

Per: ORIGINAL SIGNED BY
Name: Heather Wyatt
Title: Secretary

Per: ORIGINAL SIGNED BY
Name: Dave Matthews
Title: Chair

ATTACHMENT O

REFERENCE: 5.0 SEC-18

AMENDING AGREEMENT

THIS AMENDING AGREEMENT (the "**Agreement**"), made in duplicate, dated and effective as of November 16, 2010.

BETWEEN:

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION
(hereinafter referred to as "**OIPC**");

AND:

BRANTFORD POWER INC.
(an Ontario hereinafter referred to as the "**Borrower**")

WHEREAS the parties entered into Financing Agreement No. 09Bra904109027FA dated November 18, 2009 (the "**Financing Agreement**") a true copy of which is attached as Schedule "A" in which OIPC agreed to provide financing for the Borrower's General Capital Program and Smart Meter Project (the "**Project**") in the amount of $7,938,000.00;

AND WHEREAS pursuant to Section 18(b) of the Financing Agreement, the parties wish to amend the Financing Agreement on the terms and conditions set out in this Amending Agreement;

NOW THEREFORE in consideration of the covenants of each of the parties contained herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged by each of the parties) the parties agree as follows:

1. Capitalized terms used but not defined in this Amending Agreement shall have the meanings given in the Financing Agreement.
2. The first paragraph of Section 3 is deleted in its entirety and replaced by the following:

   "The Borrower covenants and agrees with OIPC that:".
3. The second recital of the Financing Agreement is hereby amended so OIPC agrees to make financing available to the Borrower up to a maximum aggregate principal amount of $10,338,000.00 (TEN MILLION THREE HUNDRED THIRTY EIGHT THOUSAND DOLLARS).
4. Schedule "A" of the Financing Agreement is deleted in its entirety and replaced with the new Financing Schedule attached hereto as Schedule "B".

5. The General Security Agreement dated November 18, 2009 shall apply to the new principal amount of $10,338,000.00 and continue to grant OIPC a second ranking priority security interest.

6. Section 3(o) of the Financing Agreement is deleted in its entirety and replaced with the following:

   "the Borrower shall not increase its letter of guarantee from the Royal Bank of Canada in excess of maximum amount of $9,375,721.00 unless the increase is approved by the Independent Electricity System Operator (IESO) and is pursuant to the normal course of business of the Borrower."

7. Section 3(o) of the Financing Agreement is deleted in its entirety and replaced with the following:

   "the Borrower shall not be permitted to increase its term facilities with the Royal Bank of Canada in the amounts of $4,810,000.00 and $828,000.00 during the term of this Agreement."

8. The Borrower shall provide OIPC with a new legal opinion from the Borrower's external counsel addressed to OIPC and in a form and substance satisfactory to OIPC on or prior to the next Advance made by OIPC.

9. The Borrower acknowledges and agrees that OIPC shall have the benefit of an acknowledgement and consent as more particularly described in Schedule "C" hereto.

10. The Borrower warrants that as of the date of this Amending Agreement,

    a. no act of event has occurred that constitutes an Event of Default under the Financing Agreement;

    b. all representations and warranties made by the Borrower under the Financing Agreement remain true and complete in all material respects; and

    c. there is no litigation or judicial or administrative proceeding of any kind now existing, pending or threatened that in any way seeks to restrain, enjoin, delay or otherwise adversely affect the commencement or completion of any of the Project(s) or that would substantially impair the Borrower's ability to meet its debt obligations as they generally come due or that in any manner questions the proceedings and authority under with the Project(s) or the borrowings applied for in the Application have been or will be authorized.

11. In all other respects and except as expressly amended hereunder, any and all terms of the Financing Agreement and subsequent amendments, shall remain in full force and effect.

12. This Amending Agreement may be executed by the parties in separate counterparts each of which when so executed and delivered will be an original.

IN WITNESS WHEREOF the parties have executed this Amending Agreement as of the date first mentioned above.

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

By:

Name: Bill Ralph

Title: Senior Vice President, Infrastructure Lending and Chief Risk Officer

I have authority to bind the Corporation

BRANTFORD POWER INC.

By:

Name: Brian D'Amboise
Title: Chief Financial Officer

By: ________________________________
Name: Heather Wyatt
Title: Board Secretary

We have authority to bind the Corporation

[Affix Corporate Seal]

Schedule "A"

[Insert Financing Agreement]

FINANCING AGREEMENT

THIS AGREEMENT (the "Agreement"), made in duplicate, dated and effective as of November 18, 2009 (the "Effective Date")

BETWEEN:

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION
(herein after referred to as "OIPC");

and

BRANTFORD POWER INC.
(an Ontario corporation created under the *Business Corporations Act* (Ontario) herein after referred to as the "Borrower")

WHEREAS:

OIPC has advised the Borrower that its loan application number 9027, (the "Application") has been approved;

OIPC agrees to make financing available to the Borrower up to a maximum aggregate principal amount of $7,938,000.00 (SEVEN MILLION, NINE HUNDRED THIRTY-EIGHT THOUSAND DOLLARS) (the "Committed Amount") for the projects listed in the Application and more particularly described in Schedule "A" hereto (the "Project"), subject to the terms and conditions set out in this Agreement.

NOW THEREFORE in consideration of the covenants of each of the parties contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties, the Borrower and OIPC hereby agree as follows:

1. Definitions

In this Agreement:

(a) **"Acquired Assets"** means any assets, rights or properties, of any nature or kind, acquired, constructed or improved by the Borrower or any Related Entity after the date of this Agreement and, for greater certainty, shall include any buildings or other fixtures, acquired, constructed or improved by the Borrower after the date of this Agreement.

(b) **"Advance"** means a short-term loan made by OIPC to the Borrower in Canadian dollars pursuant to the terms and conditions of this Agreement.

(c) **"Advance Date"** has the meaning given to it in paragraph 6(a) hereof.

(d) **"Advance Interest Rate"** has the meaning given to it in paragraph 9(a) hereof.

(e) "**Agreement**" means the agreement constituted by this agreement including all attached schedules and referenced documents including the debenture(s), subordination and postponement agreement and the general security agreement and the respective terms and conditions thereunder, as the same may be amended, restated, modified or replaced from time to time. Terms such as "hereof", "herein" and "hereto" refer to this Agreement.

(f) "**Applicable Law**" means, in respect of any Person, property, transaction or event, all present or future applicable laws, statutes, regulations, treaties, judgments and decrees and all present or future applicable published directives, rules, policy statements, instruments and orders of any Public Authority and all applicable orders and decrees of courts and arbitrators of like application.

(g) "**Application**" has the meaning given to it in the first recital hereof.

(h) "**Authorized Officer**" means with respect to the Borrower, the Chief Financial Officer, the Chairperson of the Board of Directors, the Board Secretary or any Executive Director or any other officer or Person designated from time to time by a resolution of the Board of Directors of the Borrower.

(i) "**Business Day**" means a day on which banking institutions in Toronto, Ontario, Canada are not authorized or obligated by law or executive order to be closed, other than Saturday or Sunday.

(j) "**Capital Lease Obligation**" means, in respect of any Person, the obligation of such Person, as lessee, to pay rent or other payment amounts under a lease of real or personal property which is required to be classified and accounted for as a capital lease or liability of such Person, in accordance with GAAP.

(k) "**Committed Amount**" has the meaning given to it in the second recital hereof.

(l) "**Current Ratio**" means current assets divided by current liabilities, where current assets shall exclude all accounts receivables due more than one hundred and twenty (120) days from affiliates or related companies.

(m) "**Debt to Capital Ratio**" means Debt divided by total Capital where:

(i) "**Debt**" means all short-term and long-term interest-bearing loans; and

(ii) "**Capital**" means Debt plus Shareholder's net worth which is defined as the sum of share capital, preferred shares and retained earnings minus advances and/or investments to/in affiliated or related companies or third party entities minus goodwill and other intangible assets.

(n) "**Debt Service Coverage Ratio**" means the sum of net profits after cash tax (excluding extraordinary items) plus depreciation/amortization, plus interest payments divided by the sum of principal and interest payments made on all interest-bearing loans, plus the trailing three-year average of Unfinanced Net Capital Expenditures, plus the dividend paid by the Borrower during the Fiscal Year in question.

(o) **"Debentures"** means secured debentures of the Borrower issued from time to time pursuant to the terms and conditions of this Agreement.

(p) **"Debenture Interest Rate"** has the meaning given to it in paragraph 11(e) hereof.

(q) **"Debenture Purchase Certificate"** means a certificate substantially in the form as provided by OIPC to the Borrower.

(r) **"Debenture Purchase Date"** has the meaning given to it in paragraph 10(a) hereof.

(s) **"Drawdown Certificate"** means a certificate substantially in the form as provided by OIPC to the Borrower.

(t) **"Eligible Borrower"** means a public body that is eligible to borrow from OIPC pursuant to the *Ontario Infrastructure Projects Corporation Act, 2006* (Ontario).

(u) **"Equity"** means, on a consolidated basis, the book value, preferred and common shares, contributed surpluses and retained earnings of the Borrower.

(v) **"Event of Default"** means any of the events described in paragraph 13(c).

(w) **"Facility Termination Date"** means the earlier of November 18, 2014 and the date on which the obligations of OIPC hereunder have been terminated pursuant to paragraphs 13(b) or 13(c) hereof.

(x) **"Financial Instrument Obligations"** means all obligations and liabilities of the Borrower or a Related Entity under or in respect of any interest or currency rate swap, forward agreement or other instrument which is a financial derivative.

(y) **"Fiscal Year"** means the fiscal year of the Borrower ending on December 31st in each calendar year.

(z) **"GAAP"** means the generally accepted accounting principles stated from time to time in the Handbook of the Canadian Institute of Chartered Accountants or some other formal source of GAAP designated as the GAAP to be applied to entities like the Borrower by the applicable accounting standards authority in Canada..

(aa) **"Indebtedness"** means, at any time and in respect of any Person, without duplication:

(i) all obligations of such Person for money borrowed including:

(A) obligations with respect to bankers' acceptances;

(B) contingent reimbursement obligations with respect to letters of credit and other financial instruments; and

(C) all Purchase Money Obligations which would be indebtedness under GAAP but excluding, for greater certainty, trade indebtedness accounted for as accounts payable, accrued expenses and other similar current liabilities incurred in the ordinary course of operations determined in accordance with GAAP;

(ii) any Capital Lease Obligation of such Person; and

(iii) all undertakings of such Person in respect of obligations of any Person of the type described in (i) which such Person has guaranteed, directly or indirectly, or the holder of which such Person has otherwise assured against loss thereon.

(bb) "**Interest Period**" for an Advance means: (i) initially, the period from and including the date of the Advance to but excluding the next following Reset Date; and (ii) subsequently, each period from and including a Reset Date to but excluding the next following Reset Date.

(cc) "**Issue Date**" for a Debenture means the date on which the Debenture is issued.

(dd) "**Lien**" means any mortgage, hypothec, lien, pledge, assignment, charge, security interest, title retention agreement intended as security, or other similar encumbrance and any other arrangement which has the effect of granting security.

(ee) "**Limited Recourse Debt**" means Indebtedness, under which recourse in respect of a default in the repayment of such Indebtedness is limited to the asset or assets acquired with such Indebtedness by the Borrower or any Related Entity.

(ff) "**Material Related Entity**" means, at any relevant time, any Related Entity, the book value of whose assets, rights and properties constitutes in excess of 10% of the book value of the assets, rights and properties of the Borrower and all its Related Entities, considered as a whole.

(gg) "**Maturity Date**" has the meaning given to it in paragraph 11(a) hereof.

(hh) "**Net Capital Expenditures**" means the capital expenditures in the period less the proceeds from the sale of the property, plant and equipment and other fixed assets.

(ii) "**Obligations**" means the amount of all Advances provided to the Borrower pursuant to this Agreement and any unpaid interest thereon.

(jj) "**Officer's Certificate**" means a certificate of the Borrower that has been signed by an Authorized Officer.

(kk) "**Permitted Liens**" means and refers to:

(i) Liens to which any Acquired Assets are subject at the time such Acquired Assets are acquired by the Borrower or any Related Entity provided that such Lien is limited to the Acquired Assets and such Lien has not been created or incurred in anticipation of such acquisition;

(ii) any Lien on or against cash or marketable debt securities to secure Financial Instrument Obligations incurred by the Borrower or any Related Entity in the course of its operations and not for speculative purposes;

(iii) any Lien in respect of a Purchase Money Obligation, Capital Lease Obligation or Limited Recourse Debt incurred in connection with or within 180 days of the acquisition, construction or improvement of any Acquired Assets and which secures the purchase price of such asset or the cost of acquiring, constructing or improving such asset provided that the amount secured by such Lien does not exceed the purchase price or cost of acquiring, constructing or improving such asset (including any applicable interest and/or lease payments to be paid);

(iv) any Liens to which assets acquired or which are deemed to have been acquired by the Borrower or any Related Entity pursuant to a merger or other combination with any other entity are subject at the time of such merger or other combination;

(v) Liens for Taxes, utility charges, levies, assessments or governmental charges:

(A) not at such time past due; or

(B) the validity of which are being contested in good faith and by appropriate proceedings;

(vi) the Lien of any judgment rendered, or claim filed, which is being contested in good faith and by appropriate proceedings;

(vii) undetermined or inchoate Liens and charges incidental to, purchases of goods, construction, maintenance or current operations which have not at such time been filed or registered pursuant to law, which relate to obligations which are at such time not past due or which, if filed or registered, are being contested in good faith and by appropriate proceedings;

(viii) easements, rights-of-way, servitudes or other similar rights in property (including rights-of-way and servitudes for railways, sewers, drains, gas and oil pipe lines, gas and water mains, electric light and power and telephone or telegraph or cable television conduits, poles, wires and cables) granted to or reserved or taken by other Persons;

(ix) security given to a public utility or any municipality or governmental or other public authority when and to the extent required by such utility or municipality or other authority in the ordinary course of operations of the Borrower or any Related Entity and not in connection with the borrowing of money or obtaining of credit by the Borrower or any Related Entity;

(x) the right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, license, franchise, grant or permit, or by any statutory provision, to terminate any such lease, license, franchise, grant or permit, or to require annual or other periodic payments as a condition of the continuance thereof;

(xi) the reservation in any original grant from the Crown of any land or interests therein and statutory exceptions to title;

(xii) Liens created or assumed by the Borrower or any Related Entity if an Authorized Officer has certified to OIPC that such Liens secure amounts which are not material having regard to the then current market value of the assets, rights and properties of the Borrower and its Related Entities, considered as a whole;

(xiii) any renewal, replacement or temporal extension (or successive renewals, replacements or extensions) in whole or in part of any Permitted Lien so long as the principal amount secured by such Permitted Lien does not exceed the principal amount secured by the Permitted Lien immediately prior to such extension;

(xiv) any and all Liens, whether direct or indirect, contingent or otherwise, to which any of the assets, rights and properties of the Borrower and its Related Entities are subject on the date of this Agreement;

(xv) Liens or any rights of distress reserved in or exercisable under any lease for rent and for compliance with the terms of such lease; and

(xvi) four (4) credit facilities that the Borrower has with the Royal Bank of Canada which include: (i) credit facility number 1, a line of credit in the maximum amount of $7,000,000.00; (ii) credit facility number 2, a letter of guarantee for the amount in the maximum amount of $9,375,721.00; (iii) credit facility number 3, a term facility in the maximum amount of $5,458,000.00; and (iv) credit facility number 4, a term facility in the maximum amount of $1,037,000.00.

(ll) "**Person**" includes an individual, firm, partnership, trust, trustee, executor, administrator, legal personal representative, government, governmental body or authority, corporation or other incorporated or unincorporated entity.

(mm) "**Prime Rate**" means, on any day, the annual rate of interest which is the arithmetic mean of the prime rates announced from time to time by the Reference Banks as their reference rates in effect on such day for Canadian dollar commercial loans made in Canada. If fewer than five of the Reference Banks quote a prime rate on such days, the "Prime Rate" shall be the arithmetic mean of the rates quoted by the remaining Reference Banks.

(nn) "**Principal Amount**" of an interest-bearing Debenture means the amount stated to be payable at maturity, exclusive of any interest.

(oo) "**Project**" has the meaning given to it in the second recital hereof.

(pp) "**Public Authority**" means any governmental, regional, municipal or local body having authority over either of the parties.

(qq) "**Purchase Money Obligation**" means any unpaid part of, or indebtedness incurred or assumed for the purpose of acquiring, a particular asset, right or property, the repayment of which is secured by recourse against such asset, right or property.

(rr) "**Reference Banks**" means, collectively, The Toronto-Dominion Bank, Bank of Nova Scotia, Bank of Montreal, Royal Bank of Canada and Canadian Imperial Bank of Commerce.

(ss) "**Related Entity**" means any company, corporation, partnership or other entity which is controlled by the Borrower either through the ownership of voting securities, by contract or otherwise.

(tt) "**Reset Date**" has the meaning given to it in paragraph 9(a) hereof.

(uu) "**Successor Entity**" has the meaning given to it in paragraph 14 hereof.

(vv) "**Taxes**" means any present or future income, excise, stamp, capital, goods and services, property or other taxes, levies or withholding imposed by any taxing authority.

(ww) "**Unfinanced Net Capital Expenditures**" means Net Capital Expenditures in the period in question less the amount of such capital expenditures financed by (i) contributed shareholder or other third party entities, and (ii) the principal portion of term debt and capital lease indebtedness.

2. Representations and Warranties

The Borrower represents and warrants to OIPC that:

(a) the information contained in the Application, to the extent that it relates to the Borrower or the Project, is true and correct in all material respects as of the date of this Agreement;

(b) the Borrower has been duly incorporated pursuant to Section 142 of the *Electricity Act*, 1998 (Ontario) as amended, all of the shares of the Borrower are held by one or more municipal corporations and the Borrower is in the business of generating, transmitting, distributing, or retailing electricity and has the corporate power and capacity to:

(i) own, lease and operate its properties and assets and to carry on its activities as a generator, transmitter, distributor or retailer of electricity;

(ii) to borrow money;

(iii) to enter into and complete the Project; and

(iv) to execute and deliver this Agreement and to perform its obligations hereunder;

(c) the Borrower has taken all necessary corporate action to authorize the execution, delivery and performance of this Agreement;

(d) the Agreement has been duly authorized, executed and delivered by the Borrower and constitutes a valid and legally binding obligation, enforceable against the Borrower in accordance with its respective terms, subject to applicable bankruptcy, insolvency and other laws affecting the enforcement of creditors' rights generally;

(e) the execution and delivery by the Borrower of this Agreement and the performance by the Borrower of its obligations hereunder do not violate, result in a breach of, or constitute a default under:

(i) any of the terms, conditions or provisions of its constating documents or by-laws of the Borrower;

(ii) any resolution of the board of directors or any financial plan, budget, borrowing strategy or investment strategy of the Borrower; or

(iii) any statute, regulation or other law applicable to the Borrower;

(f) the Borrower is not currently in default under any Indebtedness and undertakes to immediately inform OIPC if it is in default under any Indebtedness at any time; and

(g) to the best of the Borrower's knowledge, subject only to minor title defects not individually or in the aggregate material nor materially and adversely affecting the use thereof and subject to any security granted to OIPC pursuant to the provisions hereof, the Borrower has good and marketable title to its real and personal properties.

The representations and warranties set out in this paragraph 2 shall survive the execution and delivery of this Agreement and the making of any Advances to the Borrower, notwithstanding any investigations or examinations which may be made by OIPC or any counsel to it.

3. Covenants

The Borrower covenants and agrees with OIPC that, unless OIPC otherwise consents in writing, so long as any Advance is outstanding:

(a) the proceeds of all Advances provided by OIPC to the Borrower shall be applied only to capital expenditures in respect of hard and soft capital costs actually incurred or to be incurred by the Borrower, if such costs and expenditures are directly related to the Project and not for any other purpose;

(b) the proceeds of each Debenture shall be applied only to either:

(i) repayment of Advances, as more particularly set out in paragraph 11 below; or

(ii) capital expenditures in respect of hard and soft capital costs actually incurred or to be incurred if OIPC in its sole discretion has agreed to purchase a Debenture prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, by the Borrower, if such costs and expenditures are directly related to the Project in respect of which the Debenture is being issued; or

(iii) legal costs and expenses directly related to the issue of such Debenture;

and not for any other purpose;

(c) the Borrower shall duly and punctually pay or cause to be paid when due and payable the principal of and interest on all Advances and all other amounts owing in respect of all Advances, in conformity with the terms of this Agreement, and it shall faithfully observe and perform all the conditions, covenants and requirements of this Agreement;

(d) the Borrower will not, nor will it permit any Material Related Entity to, create, assume or suffer to exist any Lien upon the whole or any part of its assets, rights or properties (both real and personal, including licences, franchises, permits and leasehold interests) whether now owned or hereafter acquired if such Lien secures Indebtedness and is a Lien for the benefit of any Person other than OIPC unless such Lien is a Permitted Lien;

(e) the Borrower will not, nor will it permit any Material Related Entity to, sell, assign or otherwise dispose of any of its assets, rights and properties whether in a single transaction or a series of transactions, other than to the Borrower, unless:

(i) such sale, assignment or other disposition is not material having regard to the assets, rights and properties of the Borrower and the Material Related Entities, taken as a whole or effected in the ordinary course of operations of the Borrower or the Material Related Entities, as applicable;

(ii) the Borrower, concurrent with the completion of such sale, assignment or other disposition, provides OIPC with a certificate of an Authorized Officer to the effect that such Authorized Officer has no reason to believe that, after giving effect to such sale, assignment or other disposition, the Borrower will not be able to meet all of its financial obligations in accordance with their terms; including its obligation to pay principal and interest on the Advances; or

(iii) in the case of a disposition of all or substantially all of its assets, the Borrower complies with paragraph 14 of this Agreement;

(f) the Borrower shall as soon as practicable following the approval thereof by the Borrower and, in any event, within 120 days after the end of each Fiscal Year of the Borrower, furnish OIPC with such number of copies as OIPC may reasonably request of an annual balance sheet, statement of revenue and expense, statement of changes in net assets, statement of cash flows, prepared in accordance with GAAP as applied to the presentation of financial information of the Borrower and reported on by an independent accountant and independent auditor;

(g) the Borrower shall furnish OIPC as soon as practicable with any other financial reporting information that OIPC may require at its discretion and at any time prepared in accordance with GAAP.

(h) the Borrower will at all times maintain its existence as a body corporate with all necessary approvals to carry on its operations as a municipal corporation that generates, transmits, distributes, or retails electricity under Applicable Law and conduct its operations in a proper and efficient manner, and will keep or cause to be kept proper books of account and will take all necessary steps to ensure that its Material Related Entities conduct their operations in a proper and efficient manner and keep or cause to be kept proper books of account;

(i) the Borrower shall maintain in force with reputable insurers insurance with respect to losses of or damage to its assets (excluding distribution assets which are self-insured) from such risks, casualties and contingencies and of such types and in such amounts and subject to such deductible amounts as are customary in the case of prudent persons of established reputation engaged in the same or similar businesses with similar assets, and any other form(s) of appropriate insurance that a prudent person in the business of operating a municipal corporation for the purposes of generating, transmitting, distributing or retailing electricity under Applicable Law would maintain. The Borrower's insurance carriers and policy provisions must be acceptable to OIPC and must remain in effect for the duration of this Agreement. OIPC shall be named as an additional insured on general liability insurance policies and as a loss payee on all property insurance policies as their interest may appear. The Borrower shall submit certificates of insurance as evidence of the above required insurance to OIPC prior to any Advances pursuant to this Agreement. Subsequent to Project completion, the Borrower shall maintain adequate liability and property insurance policies naming OIPC as an additional insured and as a loss payee on said insurance policies;

(j) the Borrower shall execute and deliver the general security agreement in the form provided and attached as Schedule "E" to this Agreement in order to give OIPC a fourth (4^{th}) ranking security interest in the present assets of the Borrower as well as those assets acquired subsequent to the effective date of this Agreement; the Borrower shall have the Corporation of the City of Brantford execute a Subordination and Postponement Agreement in favour of OIPC as attached hereto as Schedule "F" in order to give OIPC a second (2^{nd}) ranking security interest in the present assets of the Borrower as well as those assets acquired subsequent to the effective date of this Agreement; such Subordination and Postponement Agreement will be effective April 1, 2010;

(k) since the date of incorporation of the Borrower, there has been no development materially adversely affecting the business or financial condition or position of the Borrower or its ability to carry on business as presently conducted or as contemplated hereunder to be conducted;

(l) the Borrower shall submit project management reports to OIPC for the Project (the "Reports") pursuant to the attached Schedule "D" to this Agreement; such Reports to be completed to the satisfaction of OIPC;

(m) the Borrower shall not issue any preferred shares without first seeking the written approval of OIPC;

(n) the Borrower shall obtain the written consent of OIPC, such consent will not be unreasonably withheld, should it require an increase in its line of credit of $7,000,000.00 with the Royal Bank of Canada, provided that such increase is in the normal course of business of the Borrower;

(o) the Borrower shall not increase its letter of guarantee from the Royal Bank of Canada in excess of maximum amount of $9,375,721.00 unless the increase is required by the Independent Electricity System Operator (IESO) and is pursuant to the normal course of business of the Borrower;

(p) the Borrower shall not be permitted to increase its term facilities with the Royal Bank of Canada in the amounts of $5,458,000.00 and $1,037,000.00 during the terms of this Agreement;

(q) the Borrower shall maintain a Debt to Capital Ratio at 75% or lower for the term of this Agreement, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable;

(r) the Borrower shall maintain a Debt Service Coverage Ratio of 1 to 1 or higher for the term of this Agreement, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable; an exception to the Debt Service Coverage Ratio target will be permissible so long as the Borrower can demonstrate to the satisfaction of OIPC that such deviation is due to an extraordinary item or is expected to be of relatively short duration without negatively impacting the general financial position of the Borrower and its ability to meet payment obligations when due during the immediate forecast period;

(s) the Borrower shall maintain its Current Ratio at 1.1:1 or higher for the term of this Agreement, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable;

(t) OIPC agrees to revise the required financial ratios as referred to in this Financing Agreement should the difference between the current accounting rules and the adoption by the Borrower of the International Financial Reporting Standards on January 1, 2011 have a material impact on its financial ratios; the revisions to the financial ratios under this Financing Agreement shall be based on the original intent of the required financial ratios under this Financing Agreement but will allow for reconciliation of the current accounting rules and the International Financial Reporting Standards;

(u) the Borrower shall notify OIPC as soon as practicable after becoming aware of the occurrence of any Event of Default or of the occurrence of any event or circumstance which, after notice or lapse of time, would become an Event of Default.

For greater certainty, OIPC is not responsible for ensuring that the proceeds of Advances and Debentures provided to the Borrower are in fact used in the manner specified in paragraphs 3(a) and 3(b) above.

4. Project Expenditure Requirements

The Borrower shall not request an Advance in respect of the Project hereunder unless expenditures in an amount no less than the amount of the Advance to be allocated to the Project have actually been incurred by the Borrower prior to the date of such request subject to the right of OIPC to waive this requirement at its sole discretion.

5. Evidence of Advances

OIPC shall open and maintain in accordance with its usual practice books of account evidencing all Advances and all other amounts owing by the Borrower to OIPC. OIPC shall enter in the foregoing accounts details of each Advance and of all amounts from time to time owing or paid by the Borrower to OIPC hereunder, the amounts of principal, interest and fees payable from time to time hereunder. The information entered in the foregoing accounts shall constitute, in the absence of manifest error, *prima facie* evidence of the obligations of the Borrower to OIPC hereunder, the date OIPC made each Advance available to the Borrower and the amounts the Borrower has paid from time to time on account of the principal of, interest on and fees related to the Advances.

6. Procedure for Obtaining Advances

(a) The Borrower may request an Advance to be made on either the 1st or the 15th day of any calendar month or the first Business Day following such date if such date is not a Business Day (either of which is defined as the "Advance Date") by delivering to OIPC at the address shown on Schedule "B" hereto no later than five (5) Business Days prior to the Advance Date on which the Advance is required, by courier or fax, an irrevocable Drawdown Certificate.

(b) The principal amount of all Advances will be tendered to the Borrower by electronic transfer of funds to an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of such deposit.

7. Conditions Precedent to Advances

OIPC shall not make any Advance until each of the following conditions precedent has been satisfied:

(a) OIPC shall have received a Drawdown Certificate in respect of the Advance requested;

(b) at OIPC's discretion, if any issues that were raised in any audit conducted under paragraph 18(a) have been resolved to OIPC's satisfaction and/or OIPC has neither required an audit under paragraph 18(a) nor is such an audit ongoing;

(c) the amount of the requested Advance when added to the aggregate amount of Advances then outstanding in respect of the Project does not exceed the Committed Amount for the Project;

(d) the representations and warranties of the Borrower set out in paragraph 2 hereof shall be true and correct as at the date of the Advance, as evidenced by a Drawdown Certificate;

(e) the Borrower shall not be in material default of any of its obligations under this Agreement as at the date of the Advance, as evidenced by a Drawdown Certificate;

(f) no Event of Default shall have occurred and be continuing;

(g) expenditures on the Project shall have been incurred subject to paragraph 4, as evidenced by a Drawdown Certificate;

(h) a legal opinion from the Borrower's external legal counsel addressed to OIPC and in the form and substance satisfactory to OIPC shall have been delivered to OIPC on or prior to the first Advance made by OIPC;

(i) at OIPC's discretion, the requested Advance when added to the aggregate amount of all Advances then outstanding does not exceed the Advance requests as noted in Schedule "A" hereto;

(j) the Borrower shall have delivered to OIPC an executed copy of the Subordination and Postponement Agreement in the form attached hereto as Schedule "F"; and

(k) OIPC shall have received evidence in the form of valid certificates of insurance from the Borrower that OIPC has been named as an additional insured on general liability insurance policies and as a loss payee on all property insurance policies as their interest may appear.

8. Conditions Precedent to Debenture Purchases

OIPC shall not purchase any Debenture until each of the following conditions precedent, has been satisfied, subject also to paragraphs 10 and 11:

(a) OIPC shall have received a Debenture Purchase Certificate;

(b) the amount from the proceeds of the Debenture purchase when added to the aggregate amount of Debentures then outstanding in respect of the Project does not exceed the Committed Amount;

(c) the representations and warranties of the Borrower set out in paragraph 2 hereof shall be true and correct as at the date of the Debenture purchase, as evidenced by a Debenture Purchase Certificate;

(d) the Borrower shall not be in material default of any of its obligations under this Agreement as at the date of the Debenture purchase, as evidenced by a Debenture Purchase Certificate;

(e) at OIPC's discretion, if any issues that were raised in any audit conducted under paragraph 18(a) have been resolved to OIPC's satisfaction and/or OIPC has neither required an audit under paragraph 18(a) nor is such an audit ongoing;

(f) no Event of Default shall have occurred and be continuing;

(g) a legal opinion from the Borrower's external legal counsel addressed to OIPC and in the form and substance satisfactory to OIPC shall have been delivered to OIPC;

(h) expenditures on the Project shall have been incurred or will be incurred if OIPC in its sole discretion has agreed to purchase a Debenture prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, as evidenced by a Debenture Purchase Certificate;

(i) OIPC shall have received evidence in the form of valid certificates of insurance from the Borrower that OIPC has been named as an additional insured on general liability insurance policies and as a loss payee on all property insurance policies as their interest may appear; and

(j) the Borrower shall have delivered to OIPC an executed copy of the Subordination and Postponement Agreement in the form attached hereto as Schedule "F".

9. Interest on Advances

(a) Each Advance shall bear interest at a floating rate per annum as determined by OIPC based on OIPC's cost of funds plus OIPC's prevailing spread assigned to the borrower sector for program delivery costs and risks (the "Advance Interest Rate"). The Advance Interest Rate for an Advance for the initial Interest Period shall be set by OIPC based on OIPC's cost of funds plus OIPC's prevailing spread assigned to the borrower sector for program delivery costs and risks and will be effective on the date of the Advance. The Advance Interest Rate for each subsequent Interest Period shall be reset on the first Business Day of each calendar month (each such Business Day, a "Reset Date") for the following Interest Period as set by OIPC at its discretion and will be effective on the Reset Date, which Advance Interest Rate as so reset shall apply to the Advance for such Interest Period until reset again.

(b) Interest accrued during an Interest Period on the principal balance of an Advance outstanding during such Interest Period shall be payable in arrears on the first Business Day of the calendar month following the Interest Period in an amount equal to the product of the Advance Interest Rate in effect during such Interest Period and the principal balance of the Advance outstanding as at the Reset Date for such Interest Period, or in the case of an initial Interest Period the principal balance outstanding on the date of the Advance, multiplied by a fraction, the numerator of which is the number of days in the Interest Period and the denominator of which is 365.

(c) Payments of interest due by the Borrower for any Advance, and any other payments due under this Agreement, shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement which Schedule forms part of this Agreement, together with such other authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

(d) The Borrower shall pay interest to OIPC on any overdue amount of principal or interest in respect of any Advance, both before and after demand, default, maturity and judgment, at a rate per annum equal to the Prime Rate plus 200 basis points, calculated on a daily basis from the date such amount becomes overdue for so long as such amount remains overdue, and the Borrower shall pay to OIPC any and all costs and losses incurred by OIPC as a result of the payment having been overdue.

(e) For purposes of disclosure pursuant to the *Interest Act* (Canada), the yearly rate of interest which is equivalent to a rate of interest payable in respect of the principal amount of any Advance for any period of less than a year may be determined by multiplying the rate of interest for such period by a fraction, the numerator of which is the actual number of days in a year commencing on and including the first day in such period and ending on but excluding the corresponding day in the next calendar year and the denominator of which is the actual number of days in such period.

10. Purchase of Debentures

(a) Provided that the Borrower is not in default under this Agreement, that all of the conditions precedent listed in paragraph 8 have been satisfied and that none of the events specified in paragraph 13(c) shall have occurred and be continuing, and upon satisfaction of such other usual and customary conditions precedent as OIPC and its legal counsel may reasonably require, and subject to paragraph 11 hereof, OIPC agrees to purchase Debentures from the Borrower on the 1st or 15th of the calendar month next following the debenture purchase date(s) as noted on the attached Schedule "A" and as determined in the sole discretion of OIPC ("Debenture Purchase Date") and/or at a time or times to be determined at the sole discretion of OIPC, on or prior to the Facility Termination Date in an aggregate Principal Amount not to exceed the Committed Amount and subject to the detailed Debenture purchase process to be provided to the Borrower.

(b) The purchase price for any Debenture issued in accordance with paragraph 10(a) shall be satisfied by virtue of and to the extent of the satisfaction of the Obligations effected by such issuance pursuant to paragraph 11(d). Satisfaction of such purchase price by such means shall be deemed to be equivalent for all purposes, to the receipt by the Borrower from OIPC of a sum of money equal to the amount of the Obligations so satisfied. If such purchase price exceeds the amount of the Obligations so satisfied, OIPC shall pay such excess to the Borrower in immediately available funds upon the issue of the Debentures.

(c) If OIPC agrees to purchase a Debenture(s) from the Borrower prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, the Borrower agrees that it will submit an annual report to OIPC, in the form to be provided by OIPC, verifying that all proceeds of such Debenture(s) have been used exclusively for the financing of the Project during the relevant period. The first such report shall be due on the first anniversary of the purchase of the Debenture(s) by OIPC and subsequent reports shall be due annually thereafter on subsequent anniversaries until such time as all the proceeds of such Debenture(s) have been expended.

(d) The purchase price for Debentures, in excess of the principal amount of any outstanding Obligations, will be tendered to the Borrower by electronic transfer of funds to an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of such deposit.

11. Issue of Debentures and Repayment of Advances

(a) Each Advance shall be due and payable in full on the earlier of the Facility Termination Date or the Debenture Purchase Date for the Project for which the Advance was made (the "Maturity Date"), subject to OIPC's right to extend the Maturity Date in its sole discretion. The Borrower shall repay the Advance on the Maturity Date by:

(i) paying an amount equal to the Advance to OIPC in immediately available funds;

(ii) converting the Advance into long term financing by issuing to OIPC one or more Debentures in a principal amount at least equal to the Advance to be repaid; or

(iii) any combination of (i) and (ii).

(b) The Borrower shall notify OIPC at least sixty (60) days in advance of the Debenture Purchase Date as noted on Schedule "A" hereto if the Debenture(s) will not be offered for purchase on such date and the Borrower shall propose another Debenture Purchase Date subject to OIPC's rights under paragraph 10(a) and subject to OIPC's right to reject the new Debenture Purchase Date.

(c) An Advance may be repaid at any time prior to its Maturity Date at the discretion of OIPC and subject to such terms and conditions as may be imposed at OIPC's discretion. The principal amount of any such repaid Advance cannot be subsequently borrowed by the Borrower.

(d) The issuance of Debentures shall satisfy the Obligations then outstanding to the extent of the aggregate Principal Amount of such issuance with the exception that any amount owing for interest on the Obligations on the Issue Date will be payable on the next following Reset Date and will not be added to the aggregate Principal Amount of such issuance. If such aggregate Principal Amount is less than the total amount of the Obligations, then the principal owing on the balance of the Obligations shall be repaid on the Issue Date to the extent of such aggregate Principal Amount and the interest owing on such balance on the Issue Date will be payable on the next following Reset Date, subject to the right of OIPC to permit the Borrower to satisfy the said balance of the Obligations at a later date.

(e) The interest rate for each Debenture (the "Debenture Interest Rate") shall be fixed by OIPC based on OIPC's cost of funds plus OIPC's prevailing spread assigned to the borrower sector for program delivery costs and risks. A rate confirmation letter will be sent to the Borrower by OIPC confirming the interest rate to be offered for the Debenture and the Borrower's acceptance of such rate shall be conclusive proof of acceptance of the rate offered.

(f) Payments of principal and interest due on each Debenture, and any other payments due under this Agreement, shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement, together with such other authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

12. Security and Standby Fees

(a) As continuing collateral security for the payment by the Borrower to OIPC under the terms of this Agreement and for performance by the Borrower of its obligations hereunder, the Borrower acknowledges and agrees that OIPC is to have the benefit of:

(i) a general security agreement as more particularly described in Schedule "E" hereto; and

(ii) a Subordination and Postponement Agreement as more particularly described in Schedule "F" hereto.

(b) The Borrower shall pay OIPC a standby fee (the "Standby Fee") calculated at the rate of 25 basis points (0.25% per annum) on the unadvanced balance of the Committed Amount should the Borrower fail to draw any funds pursuant to this Agreement from OIPC during any period of twelve (12) consecutive months commencing initially from the Effective Date of this Agreement and subsequently from the date of the draw of any such funds until the earlier of the Facility Termination Date or the full advance of the Committed Amount. The Standby Fee shall be calculated daily on the basis of a calendar year of 365 or 366 days, as the case may be, and shall be due and payable by the Borrower monthly in arrears on the last Business Day of each month in accordance with the pre-authorized debit procedure outlined in paragraphs 9(c) and 11(f) above.

13. Term, Termination and Default

(a) This Agreement shall terminate ten (10) Business Days following the date on which the last Obligations outstanding hereunder are paid in full or following the last payment made by the Borrower to OIPC as specified on the Debenture(s) and or general security agreement pursuant to this Agreement unless earlier terminated in accordance with paragraphs (b) or (c) below.

(b) OIPC may terminate its obligations under this Agreement on thirty (30) days prior notice in writing to the Borrower if in the reasonable opinion of OIPC the Borrower is in material default under this Agreement, other than for any cause enumerated in (c) below or if OIPC rejects a new Debenture Purchase Date pursuant to section 11(b).

(c) OIPC may terminate any or all of its obligations under this Agreement immediately, subject to paragraph (d) below,

(i) if the Borrower:

(A) fails to make one or more payments of principal or interest in respect of any Advance or Debenture within five (5) Business Days after the same becomes due and payable;

(B) reaches or exceeds any updated debt and financial obligation limit imposed by its by-laws or any resolution of the Board of Directors of the Borrower;

(C) has failed to pay principal of or interest on any Indebtedness other than the Advances or Debentures issued under this Agreement when due and such default continues for five (5) Business Days;

(D) has failed to meet and pay any of its liabilities and obligations other than Indebtedness when due and default in payment is occasioned from financial difficulties affecting the Borrower;

(E) has become involved in financial difficulties such that default or unusual difficulty in meeting debts or obligations or in providing adequate funds to meet current expenditures will ensue;

(F) uses any Advance or the proceeds of any Debenture financing provided by OIPC for any purpose other than financing the Project;

(G) takes any action to authorize the termination of the existence of the Borrower or a resolution is passed authorizing the termination of the existence of the Borrower, unless such action or resolution is being pursued by the Borrower on the basis that it has made provision for payment of all of its Indebtedness including all of the Advances and Debentures issued under this Agreement, that no court proceedings are pending against it and that it has obtained the approval of its creditors to a plan for the rateable distribution of all of its property; or

(H) is subject to any proceeding whereby such proceeding shall be instituted against the Borrower or applying to a substantial part of its property or assets seeking to adjudicate it a bankrupt or insolvent, or seeking liquidation, dissolution, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or any substantial part of its property or debt under any law relating to bankruptcy, insolvency or reorganization or relief of debts, or seeking an order for relief or the appointment of a receiver, trustee or other similar official for it or for any substantial part of its property and such proceeding shall have continued undismissed or unstayed for sixty (60) days, or a creditor or creditors of the Borrower shall privately appoint a receiver, trustee or similar official for any substantial part of the property of the Borrower and, if the Borrower shall be contesting such appointment in good faith, such appointment shall continue for ninety (90) days; or any such action or proceeding shall have been consented to or not expeditiously opposed by the Borrower;

(ii) if the Borrower shall fail to observe or perform any covenant or condition contained herein and the Borrower shall not make good such default within a period of thirty (30) days after written notice has been given to the Borrower by OIPC;

(iii) if the representations and warranties made by the Borrower in this Agreement and/or the Application, or in any certificate or other document delivered hereunder shall be incorrect in any material respect when made and, if such incorrect representation or warranty is curable, the Borrower shall fail to make good such default within a period of thirty (30) days after notice in writing has been given to the Borrower by OIPC;

(iv) if issues raised in an audit required under paragraph 18(a) have not been resolved to OIPC's satisfaction within a reasonable time after the Borrower has been notified of such issues;

(v) if the report of the auditors on any annual financial statements delivered pursuant to paragraph 3(f) or any other financial information requested by OIPC delivered pursuant to paragraph 3(g) hereof shall be qualified in any way which OIPC acting reasonably deems to be materially adverse or if the Borrower should fail to supply any documents requested pursuant to paragraphs 3(f) and (g);

(vi) if any final judgment is obtained against the Borrower for an amount in excess of $100,000 and, within 10 days of the obtaining thereof, such judgment has not been discharged or execution thereunder stayed; or

(vii) if at any time any licence or approvals required by the Borrower by any Applicable Law or Public Authority to carry on the business of a municipal corporation for the purposes of generating, transmitting, distributing or retailing electricity has been assigned, cancelled or suspended;

(viii) if the Borrower shall fail to have obtained the consent required under paragraph 14(i);

(ix) if the Borrower shall enter into any Indebtedness which is senior to any Indebtedness to OIPC, other than pursuant to this Agreement, subsequent to the date of this Agreement without the prior written consent of OIPC or

(x) if the shares of the Borrower are no longer held exclusively by one or more municipal corporations as further described in paragraph 2(b) above.

(d) If OIPC elects to terminate its obligations under this Agreement pursuant to paragraph 13(c) hereof, it shall give notice in writing of such termination to the Borrower, specifying the reason for such termination. Upon delivery of such notice OIPC shall have no further obligation to make any Advances or to purchase any Debentures hereunder. In such notice OIPC may also declare all Obligations and Debentures outstanding hereunder to be immediately due and payable, whereupon such Obligations and Debentures shall become immediately due and payable pursuant to paragraph 11(f) in addition to any other rights or remedies that OIPC may have at law or in equity to enforce such Obligations and Debentures.

(e) No delay on the part of OIPC in exercising any remedy and no waiver by OIPC of any of its rights against the Borrower shall operate as a waiver of any other rights nor shall any single or partial exercise of any remedy against the Borrower restrict other or further exercises of such remedy, all remedies being cumulative and not exclusive.

(f) If OIPC elects to terminate its obligations under this Agreement in accordance with paragraphs 13(b) or (c) above, OIPC, at its discretion, shall assess any losses that it may incur as a result of the early termination as follows: if on the date of termination the outstanding principal balance on the Debenture is less than the net present value of the Debenture, the Borrower shall pay the difference between these two amounts to OIPC. Net present value will be calculated based on the following formulae: For Bullet Debenture – [(principal) / (1+(r/2))^n] + [interest payment /(r/2))*(1-(1/(1+(r/2))^n)] or for Serial Debenture – [(principal) / (1+(r/2))^n] + [interest payment /(r/2))*(1-(1/(1+(r/2))^n)] for each remaining serial principal repayment or for Amortizing Debenture – [loan payment /(r/2))*(1-1/(1+(r/2))^n)], where "r" is the prevailing lending rate less an appropriate basis point deduction for costs incurred and "n" is the number of semi-annual periods to maturity.

14. Successor Corporations

The Borrower may:

(a) amalgamate, merge, consolidate or otherwise combine pursuant to statute or by private agreement with any other Person, or

(b) sell, lease or otherwise dispose of all or substantially all of its assets, rights and properties, whether in a single transaction or a series of related transactions, to any other Person;

provided, in either case that:

(i) the prior written consent of OIPC is obtained;

(ii) the resulting or acquiring entity (the "Successor Entity") is a body corporate existing and organized under the laws of Canada or any province or territory thereof;

(iii) the Successor Entity is an Eligible Borrower;

(iv) the Successor Entity expressly assumes the due and punctual payment of the principal of, and all interest on all Advances and all other amounts owing hereunder and the performance and observance of all of the covenants and conditions of this Agreement on the part of the Borrower to be performed;

(v) the Successor Entity delivers an opinion acceptable to counsel for OIPC, acting reasonably, to the effect that the Successor Entity has validly assumed such obligations; and

(vi) no Event of Default shall have occurred or be continuing as of the effective date of each such transaction or shall arise as of the effective date of each such transaction and as a result thereof and the Borrower shall have provided OIPC with an Officer's Certificate to such effect.

15. Communications Requirements

(a) OIPC and the Borrower will work together to ensure that OIPC financing of the Project receives recognition and prominence through agreed upon communications activities. An example of such activity could include signage at the project site signifying Government of Ontario project financing.

(b) OIPC reserves the right to undertake its own communications activities in relation to OIPC financing of the Project at anytime in its sole discretion and at its expense.

(c) All joint communications activities between the Borrower and OIPC must comply with the Government of Ontario's Visual Identity Directive and guidelines.

16. Project Management Requirements

(a) As a condition of OIPC making financing available to the Borrower as further described in the second recital hereof, the Borrower shall: (1) be required to have a qualified project manager in place for the Project subject to OIPC approval; (2) comply with OIPC's project management reporting requirements for the Project; and (3) shall submit the Reports to OIPC pursuant to and as further described in the attached Schedule "D" to this Agreement.

(b) Reports submitted by the Borrower to OIPC are for OIPC's reference only and in no way shall OIPC, its officers, directors, agents, subcontractors, or employees be held responsible or liable at law for: (a) any claim, demand or action brought forward by any party against OIPC; and (b) direct consequential damages, including bodily injury, death or property damages, arising out of or in any way related to the Reports, this Agreement or the Project.

17. Indemnity

To the fullest extent permitted by law, the Borrower shall indemnify and hold harmless OIPC, its officers, directors, employees and agents (the "Indemnified Parties") from and against all (a) claims and causes of action, pending or threatened, of any kind (whether based in contract, tort or otherwise) by third parties or by whomever made related to or arising out of or in any way related to the Reports, this Agreement or the Project and (b) liabilities, losses, damages, costs and expenses (including, reasonable legal fees and disbursements) suffered or incurred by any of the Indemnified Parties in connection with any claims or causes of action described in (a) above. The obligations contained in this paragraph shall survive the termination or expiry of this Agreement.

18. General Provisions

(a) OIPC reserves the right to audit compliance with this Agreement at any time. Such right will survive any termination of this Agreement. The cost of any such audit will be at OIPC's or the Borrower's expense at OIPC's discretion. The Borrower is required to keep any supporting documents required for any such audit for a minimum of seven (7) years.

(b) No amendment, supplement, restatement or termination of any provision of this Agreement is binding unless it is in writing and signed by each party.

(c) The Borrower may not assign its rights or transfer its obligations under this Agreement without the prior written consent of OIPC. OIPC may assign its rights or transfer its obligations under this Agreement without the prior written consent of the Borrower by giving thirty (30) days notice of such assignment or transfer to the Borrower. This Agreement enures to the benefit of and binds the parties and their respective successors and permitted assigns.

(d) This Agreement, together with the Schedules, the Application, the Drawdown Certificate, the Debenture Purchase Certificate, the Officer's Certificates delivered hereunder, the annual report provided for in paragraph 10(c) hereof, the Debenture(s) and the general security agreement and their respective terms and conditions delivered hereunder constitute the entire agreement between the parties with respect to the subject matter referenced in those documents and supersedes all prior agreements, negotiations, discussions, undertakings, representations, warranties and understandings, whether written or oral.

(e) Each party shall from time to time promptly execute and deliver all further documents and take all further action reasonably necessary or appropriate to give effect to the provisions and intent of this Agreement.

(f) This Agreement is governed by, and is to be construed and interpreted in accordance with, the laws of the Province of Ontario and the federal laws of Canada applicable in the Province of Ontario.

(g) This Agreement and any amendment, supplement, restatement or termination of any provision of this Agreement may be executed and delivered in any number of counterparts, each of which when executed and delivered is an original but all of which taken together constitute one and the same instrument.

(h) Either party may deliver an executed copy of this Agreement by fax but that party shall immediately deliver to the other party an original executed copy of this Agreement.

(i) Unless otherwise specified, each notice to a party must be given in writing and delivered personally or by courier, sent by prepaid registered mail or transmitted by fax to the address or fax number set out in Schedule "B".

(j) If any provision of this Agreement is or becomes illegal, invalid or unenforceable in any jurisdiction, the illegality, invalidity or unenforceability of that provision will not affect:

(i) the legality, validity or enforceability of the remaining provisions of this Agreement; or

(ii) the legality, validity or enforceability of that provision in any other jurisdiction.

(k) All covenants, agreements, representations and warranties made herein or in any document delivered pursuant to the provisions hereof are material, shall be deemed to have been relied upon by each party hereto and, notwithstanding any investigation heretofore or hereafter made by such party shall survive the execution and delivery of this Agreement until all amounts owing pursuant to the provisions hereof have been paid in full.

(l) Words importing the singular include the plural and vice versa.

IN WITNESS WHEREOF the parties hereto have executed this Agreement effective as of the date first above written.

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

By:

Name: Bill Ralph

Title: Senior Vice President, Infrastructure Lending and Chief Financial Officer

I have authority to bind the Corporation.

BRANTFORD POWER INC.

By:

Name: Brian D'Amboise
Title: Chief Financial Officer

I have authority to bind the Corporation.

By:

Name: Heather Wyatt
Title: Board Secretary

I have authority to bind the Corporation.

SCHEDULE "A"

FINANCING SCHEDULE

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2009/2010**

Date: **Sep 11, 2009**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$7,938,000.00**

Please review, complete areas where indicated, sign, date and return the form to OIPC. The following information will be incorporated into the OIPC Financing Agreement.

The following lists the project information outlined in your application. Please verify that the project details are correct. You may amend the project completion dates or the total project cost if this information has changed since the application was submitted. Transfers between projects or categories are at OIPC's discretion and require pre-approval.

A Project Details

	Project Information						Financing Information					
App ID	Project Name	Category	Start Date (mm/dd/yyyy)	Completion Date (mm/dd/yyyy)	Total Project Cost	OIPC Loan Amount	Project ID	Term	Type	Amount	Application Request Date * (mm/dd/yyyy)	Revised Request Date (mm/dd/yyyy)
9027	2009 General Capital Program	MCOther	1/2/2009	12/31/2009	$5,229,000.00	$2,400,000.00	6287	25 y	Amortizing	$2,400,000.00	12/1/2009	09/30/2010
9027	Smart Meter Project	MCOther	4/1/2009	12/31/2010	$5,538,000.00	$5,538,000.00	6288	15 y	Amortizing	$5,538,000.00	6/30/2010	03/31/2011
					$10,767,000.00	$7,938,000.00				$7,938,000.00		

* **Please note, debentures are to be purchased after expenditures have been incurred. Please review and adjust the Application Debenture Purchase Date if required ensuring adequate time for the debenture purchase. For further clarifications or questions, please contact Debbie Chen-yin, Loan Operations, Community Loans Management at 416-326-1149.**

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2009/2010**

Date: **Sep 11, 2009**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$7,938,000.00**

B Construction Financing Quarterly Forecast

If you wish to participate in the construction loan program, please indicate the amount of construction financing you require per fiscal quarter and per debenture. A reminder that OIPC provides construction advances based on incurred project expenditures, unless prior approval has been sought.

Project ID	JUL-SEP 2009	OCT-DEC 2009	JAN-MAR 2010	APR-JUN 2010	JUL-SEP 2010	OCT-DEC 2010	JAN-MAR 2011	APR-JUN 2011	JUL-SEP 2011	OCT-DEC 2011
6287	-	2,400,000	-	-	-	-	-	-	-	-
6288	-	1,451,000	817000	817000	817000	817000	819000	-	-	-

Project ID	JAN-MAR 2012	APR-JUN 2012	JUL-SEP 2012	OCT-DEC 2012	JAN-MAR 2013	APR-JUN 2013	JUL-SEP 2013	OCT-DEC 2013	JAN-MAR 2014	APR-JUN 2014
6287	-	-	-	-	-	-	-	-	-	-
6288	-	-	-	-	-	-	-	-	-	-

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2009/2010**

Date: **Sep 11, 2009**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$7,938,000.00**

C Authorization

I agree that these are the terms for the OIPC loan. I understand that OIPC will use this information to draft the Financing Agreement.

BRIAN D'AMBOISE

Treasurer
PRINT NAME

Signature

Nov 18, 2009
Date

DIRECTIONS: Please mail or courier the original signed Financing Schedule to OIPC, 777 Bay Street, 9th Floor, Toronto, ON M5G 2C8

SCHEDULE "B"

ADDRESSES FOR NOTICE

Ontario Infrastructure Projects Corporation
777 Bay Street, 9^{th} Floor
Toronto, Ontario M5G 2C8

Attn: Director, Loans Operations
Tel.: 416-326-1149
Fax: 416-263-5900

Brantford Power Inc.
84 Market Street PO Box 308
Brantford, Ontario N3T 5N8

Attn: Brian D'Amboise, CA,
Tel.: 519-759-4222 x3234
Fax: 519-759-8129

PRE-AUTHORIZED DEBIT ("PAD") AND ACCOUNT FOR DEPOSIT

BRANTFORD POWER INC.

(1) Account Holder Information

Full Legal Name: Brantford Power Inc.

Exact account name: Brantford Power Inc.

Address: 84 Market Street City: Brantford

Province: ON Postal Code: N3T 5N8 Phone #: 519-759-4150

(2) Financial Institution Information **(Note: Please attach VOID cheque)**

(i) Inflow of Deposits

Name of Financial Institution: Royal Bank of Canada

Address: 22 Colborne Street City: Brantford

Province: ON Postal Code: N3T 2G2 Phone #: 519-758-2075

Transit #: 00522 Institution #: 003 Account #: 100-883-8

(ii) Outflow of Pre-Authorized Debit

- ☐ Same as above
- ☐ If different from above fill out banking information below

Name of Financial Institution: ______________________

Address: ______________________ City: ____________

Province: ________ Postal Code: ____________ Phone #: ____________

Transit #: ____________ Institution #: __________ Account #: ____________

Sample of the numbering at the bottom of a cheque

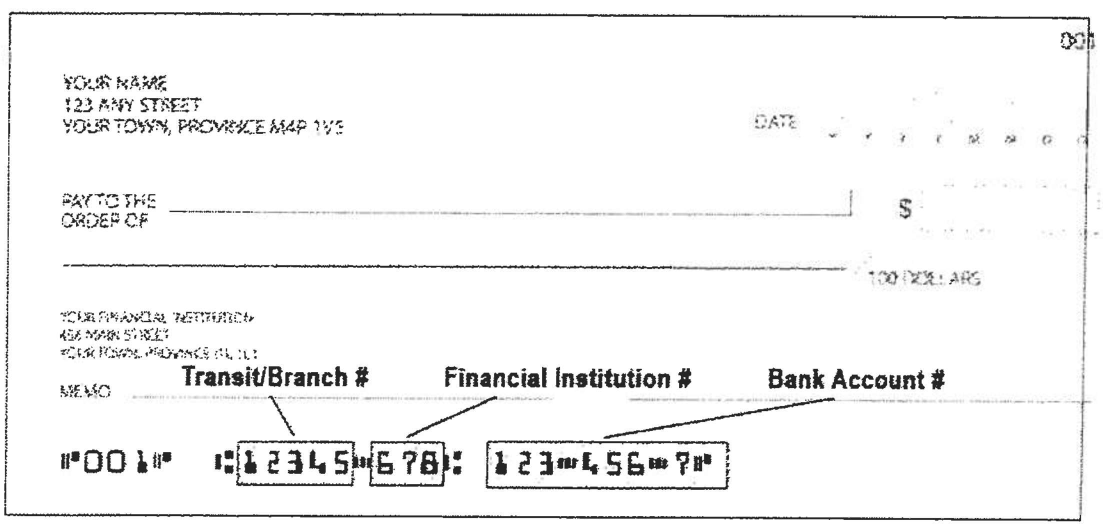
001234	01234 - 001		111-222-3
⇩ Cheque #	⇙ Transit #	⇘ Institution #	⇩ Account #

PRE-AUTHORIZED DEBIT ("PAD") AND ACCOUNT FOR DEPOSIT

BRANTFORD POWER INC.

Attach VOID Cheque Here: See attached

Sample:



RBC Royal Bank®

E-FORM 1701 (10/2009)

RBC Royal Bank
BRANT & COLBORNE BR
22 COLBORNE ST
BRANTFORD ON N3T 2G2

November 30, 2009

Tel: (519) 758-2056
Fax:(519) 758-2080

To: Whom it may concern

Re : **Brantford Power Inc.**

Please accept this copy of a VOID cheque as confirmation of the above mentioned client's banking account information for purposes of pre-authorized debit or credit.

Brantford Power Inc.
84 MARKET STREET
BRANTFORD ON N3T5N8

YYYY MM DD

Client Name and Address

PAY TO THE ORDER OF $

/DOLLARS

VOID

ROYAL BANK OF CANADA
BRANT & COLBORNE BR
22 COLBORNE ST
BRANTFORD ON N3T 2G2

Assigned Transit Address

MEMO

00522 - 003 - 100-883-8
Transit Account Number

Sincerely,

Maya
Account Manager Name

CSR
Title

1. Purpose of Debits

[X] Business PAD

2. Pre Notification of Amounts

Fixed Amounts: The Company will provide written notice of the amount to be debited and the date of the debit at least ten (10) calendar days before the date of the first debit and every time there is a change in the amount or payment date.

Variable Amounts: The Company will provide written notice of each amount to be debited and the date of the debit at least ten (10) calendar days before the date of each debit.

The Customer and Company agree to waive the above pre notification requirements.

Authorized Signature of Customer: ______________________
BRANTFORD POWER INC.

Authorized Signature of Customer: ______________________
BRANTFORD POWER INC.

Authorized Signature of Company: ______________________
OIPC

3. Rights of Dispute

The Customer may dispute a debit under the following conditions: (i) the debit was not drawn in accordance with this Authorization; (ii) this Authorization was revoked or cancelled; or (iii) prenotification (as set out in paragraph 2 above) was not received.

In order to be reimbursed, the Customer must complete a Declaration Form at the above indicated branch of the Bank up to and including ten (10) calendar days, after the date on which the debit in dispute was posted to the Customer's account.

The Customer acknowledges that disputes after the above noted time limitations are matters to be resolved solely between the Company and Customer.

4. Terms of Authorization to Debit the Above Account

The Customer authorizes the Company to debit the above account(s) in the amount of $_________(intentionally left blank)________ for payments payable to the Company in respect of its indebtedness to OIPC as further identified in the Financing Agreement between the Company and the Customer.

The Bank is not required to verify that any debits drawn by the Company are in accordance with this Authorization or the agreement made between the Customer and the Company.

This authorization is to remain in effect until the Company has received written notification from the Customer of its change or termination. This notification must be received at least thirty (30) days before the next scheduled debit by the Company from the account(s) noted above. The Customer may obtain a sample cancellation form, or more information on the right to cancel a PAD Agreement by visiting www.cdnpay.ca. This Authorization applies only to a method of payment and cancellation of this Authorization does not mean that the Customer's contractual obligations to the Company are ended.

The Customer will notify the Company promptly in writing if there is any change in the above account information.

Ontario Infrastructure Projects Corporation
777 Bay Street, 9th Floor
Toronto, ON M5G 2C8
Attention: Loan Operations Manager

The Customer has certain recourse rights if any debit does not comply with this agreement. For example, the Customer has the right to receive reimbursement for any PAD that is not authorized or is not consistent with this PAD. To obtain more information on the Customer's recourse rights, the Customer can visit www.cdnpay.ca.

Any delivery of this Authorization to the Company constitutes delivery by the Customer to the Bank. It is warranted by the Customer that all persons whose signatures are required to sign on the above account have signed this Authorization. The Customer acknowledges receipt of a signed copy of this Authorization.

_______________________________ Nov. 19/09

Signature(s) or Authorized Signature(s) of Account Holder(s) **(Date)**

_______________________________ Nov 19/09

Signature(s) or Authorized Signature(s) of Account Holder(s) **(Date)**

SCHEDULE "D"

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION PROJECT MANAGEMENT AND BEST PRACTICES REPORTING REQUIREMENTS

Construction Reporting

To help ensure effective and efficient delivery of projects financed (in whole or in part) with funds from the Infrastructure Ontario Loan Program, Ontario Infrastructure Projects Corporation (Infrastructure Ontario) has introduced reporting requirements for all **capital construction projects**. Borrowers are responsible to submit project reports according to the Estimated Project Start Date as indicated in their online application.

Depending on the size of the project, borrowers will be subject to the following requirements.

For projects under $10,000,000, borrowers will:

- Be required to have a qualified project manager in place for the Project subject to OIPC approval
- Submit standard **quarterly** project management report(s)
- For projects three months in duration or less, only a **final** report is required

For projects over $10,000,000, borrowers will:

- Be required to have a qualified project manager in place for the Project subject to OIPC approval
- Submit **monthly** project management reports using the Infrastructure Ontario template prior to the end of the second week of each month (for the preceding month)
- The final project management report shall be submitted to Infrastructure Ontario one month after the Project is completed in accordance with subsection 2(3) of the *Construction Lien Act* (Ontario)

Please forward all reports to:
Mail: Customer Relations Coordinator
Infrastructure Ontario
777 Bay St., 9th Fl.
Toronto, Ontario M5G 2C8

Email: Customer.Relations@infrastructureontario.ca
Fax: (416) 263-5900

For more details on Project Management and Best Practices Reporting, please visit *www.infrastructureontario.ca/private/pmr/index.asp*.

SCHEDULE "E"

GENERAL SECURITY AGREEMENT

For valuable consideration the undersigned (the "Borrower") agrees with Ontario Infrastructure Projects Corporation ("OIPC") as follows:

1. GRANT OF SECURITY INTEREST

As general and continuing security for the payment and performance when due of all Obligations, the Borrower hereby mortgages, charges and assigns to OIPC, and grants to OIPC, and OIPC takes, a Security Interest in the property described in the following paragraphs of this section, and in all property described in any schedules, documents or listings that the Borrower may from time to time sign and provide to OIPC in connection with this Agreement, and in all present and future Accessions to, and all Proceeds of, any such property (collectively, the "Collateral") as a general and continuing collateral security for the due payment of the obligations payable under the Financing Agreement (the "Financing Agreement") dated and effective as of November 18, 2009 and made between the Borrower and Ontario Infrastructure Projects Corporation:

(a) **Accounts Receivable.** All debts, book debts, accounts, claims, demands, money and choses in action, including without limitation, all claims against Her Majesty the Queen in right of Canada or any Province (other than Ontario) or Territory and all claims and benefits under any insurance policies;

(b) **Inventory.** All inventory, including, without limitation, all goods, merchandise, raw materials, goods in process, finished goods and other tangible personal property now or hereafter held for sale, lease or resale or that are to be furnished or have been furnished under a contract of service or that are used or consumed in the business of the Borrower;

(c) **Equipment.** All goods which are not inventory or consumer goods, including, without limitation, all fixtures, equipment, machinery, vehicles and other tangible personal property;

(d) **Chattel Paper, Instruments, Securities etc.** All chattel paper, instruments, warehouse receipts, bills of lading and other documents of title, whether negotiable or non-negotiable, shares, stock, warrants, bonds, debentures, debenture stock and other securities;

(e) **Intangibles.** All intangibles, including, without limitation, all contractual rights, goodwill, patents, trade-marks, copyrights, industrial designs and other industrial or intellectual property or rights therein;

(f) **Books and Accounts, etc.** All books, accounts, invoices, letters, papers, writings, certificates, receipts, documents and other records and data in any form or medium evidencing, representing, creating, giving rise to any rights in respect of or otherwise relating to the property described in paragraphs (a) to (e) inclusive;

(g) **Real Property.** All real and immovable property, wherever situate, and all buildings, structures, fixtures, hereditaments and appurtenances thereon or relating thereto; and

(h) **Proceeds.** All property in any form derived directly or indirectly from any dealing with any undertaking or property subject to the Security Interest or that indemnifies or compensates for such undertaking or property being destroyed, damaged, expropriated, stolen or lost and proceeds or proceeds whether of the same type or kind as the original proceeds.

2. GOVERNING LAW

This Agreement is governed by the laws of Ontario.

BRANTFORD POWER INC.

By:
Name: Brian D'Amboise
Title: Chief Financial Officer

I have authority to bind the Corporation.

By:
Name: Heather Wyatt
Title: Board Secretary

I have authority to bind the Corporation.
[Affix Corporate Seal]

ADDITIONAL TERMS AND CONDITIONS. THE ADDITIONAL TERMS AND CONDITIONS (INCLUDING ANY SCHEDULES) ON THE FOLLOWING PAGES FORM PART OF THIS AGREEMENT.

The Borrower has signed this Agreement on November 18, 2009.

GENERAL SECURITY AGREEMENT
ADDITIONAL TERMS AND CONDITIONS

3. FINANCING AGREEMENT

Reference is hereby expressly made to the Financing Agreement and all instruments supplemental thereto for a statement and description of, among other things, the liability of the Borrower for payment of the Obligations, the terms, conditions, covenants and warranties upon which the Obligations are issued and held, and the rights and remedies of OIPC, all to the same effect as if the provisions of the Financing Agreement were herein set out.

4. PLACES OF BUSINESS

The Borrower represents and warrants that the locations of all existing Places of Business are specified in Schedule AA. The Borrower will promptly notify OIPC in writing of any additional Places of Business as soon as they are established. Subject to Section 5, the Collateral will at all times be kept at the Places of Business and will not be removed without OIPC's prior written consent.

5. COLLATERAL FREE OF CHARGES

The Borrower represents and warrants that the Collateral is, and agrees that the Collateral will at all times be free, of any Charge or trust except in favour of OIPC or incurred with OIPC's prior written consent. OIPC may, but will not have to, pay any amount or take any action required to remove or redeem any unauthorized Charge. The Borrower will immediately reimburse OIPC for any amount so paid and will indemnify OIPC in respect of any action so taken.

6. USE OF COLLATERAL

The Borrower will not, without OIPC's prior written consent, sell, lease or otherwise dispose of any of the Collateral (other than Inventory, which may be sold, leased or otherwise disposed of in the ordinary course of the Borrower's business). All Proceeds of the Collateral (including among other things received in respect of Receivables), whether or not arising in the ordinary course of the Borrower's business, will be received by the Borrower as trustee for OIPC and will be immediately paid to OIPC.

7. INSURANCE

The Borrower will keep the Collateral insured to its full insurable value against loss or damage by fire and such other risks as are customarily insured for property similar to the Collateral (and against such other risks as OIPC may reasonably require). At OIPC's request, all policies in respect of such insurance will contain a loss payable clause in favour of OIPC. The Borrower will, from time to time at OIPC's request, deliver such policies (or satisfactory evidence of such policies) to OIPC. If the Borrower does not obtain or maintain such insurance, OIPC may, but will not have to, do so. The Borrower will immediately reimburse OIPC for any amount so paid. The Borrower will promptly give OIPC written notice of any loss or damage to all or any part of the Collateral that will impair the Borrower's obligations under the Financing Agreement.

8. INFORMATION AND INSPECTION

The Borrower will from time to time immediately give OIPC in writing all information requested by OIPC relating to the Collateral, the Places of Business, and the Borrower's financial or business affairs. The Borrower will promptly advise OIPC of the Serial Number, model year, make and model of each Serial Number Good at any time included in the Collateral that is held as Equipment, including in circumstances where the Borrower ceases holding such Serial Number Good as Inventory and begins holding it as Equipment. OIPC may from time to time inspect any Books and Records and any Collateral, wherever located. For that purpose OIPC may, without charge, have access to each Place of Business and to all mechanical or electronic equipment, devices and processes where any of them may be stored or from which any of them may be retrieved. The Borrower authorizes any Person holding any Books and Records to make them available to OIPC, in a readable form upon request by OIPC.

9. RECEIVABLES

If the Collateral includes Receivables, OIPC may advise any Person who is liable to make any payment to the Borrower of the existence of this Agreement. OIPC may from time to time confirm with such Persons the existence and the amount of the Receivables. Upon an Event of Default, OIPC may collect and otherwise deal with the Receivables in such manner and upon such terms, as OIPC considers appropriate.

10. RECEIPTS PRIOR TO DEFAULT

Until an Event of Default, all amounts received by OIPC as Proceeds of the Collateral will be applied on account of the Obligations in such manner and at such times as OIPC may consider appropriate or, at OIPC's option, may be held unappropriated in a collateral account or released to the Borrower.

11. DEFAULT

(1) **Events of Default.** "Event of Default" means any of the events described in paragraph 13(c) of the Financing Agreement. In case an Event of Default shall occur and be continuing, the full unpaid principal amount together with interest accrued thereon of any obligations outstanding payable under the Financing Agreement at the time of the occurrence, may become or be declared due before stated maturity by OIPC.

(2) **Additional Rights upon Default**. Upon the occurrence of any Event of Default, OIPC and a Receiver, as applicable, will to the extent permitted by law have the following additional rights:

(a) Appointment of Receiver. OIPC may by instrument in writing appoint any Person as a Receiver of all or any part of the Collateral. OIPC may from time to time remove or replace a Receiver, or make application to any court of competent jurisdiction for the appointment of a Receiver. Any Receiver appointed by OIPC will (for purposes relating to responsibility for the Receiver's acts or omissions) be considered to be the Borrower's agent. OIPC may from time to time fix the Receiver's remuneration and the Borrower will pay OIPC the amount of such remuneration. OIPC will not be liable to the Borrower or any other Person in connection with appointing or not appointing a Receiver or in connection with the Receiver's actions or omissions.

(b) Dealings with the Collateral. OIPC or a Receiver may take possession of all or any part of the Collateral and retain it for as long as OIPC or the Receiver considers appropriate, receive any rents and profits from the Collateral, carry on (or concur in carrying on) all or any part of the Borrower's business or refrain from doing so, borrow on the security of the Collateral, repair the Collateral, process the Collateral, prepare the Collateral for sale, lease or other disposition, and sell or lease (or concur in selling or leasing) or otherwise dispose of the Collateral on such terms and conditions (including among other things by arrangement providing for deferred payment) as OIPC or the Receiver considers appropriate. OIPC or the Receiver may (without charge and to the exclusion of all other Persons including the Borrower), enter upon any Place of Business.

(c) Realization. OIPC or a Receiver may use, collect, sell, lease or otherwise dispose of, realize upon, release to the Borrower or other Persons and otherwise deal with, the Collateral in such manner, upon such terms (including among other things by arrangement providing for deferred payment) and at such times as OIPC or the Receiver considers appropriate. OIPC or the Receiver may make any sale, lease or other disposition of the Collateral in the name of and on behalf of the Borrower or otherwise.

(d) Application of Proceeds After Default. All Proceeds of Collateral received by OIPC or a Receiver may be applied to discharge or satisfy any expenses (including among other things the Receiver's remuneration and other expenses of enforcing OIPC's rights under this Agreement), Charges, borrowings, taxes and other outgoings affecting the Collateral or which are considered advisable by OIPC or the Receiver to preserve, repair, process, maintain or enhance the Collateral or prepare it for sale, lease or other disposition, or to sell, lease or otherwise dispose of the Collateral. The balance of such Proceeds will be applied to the Obligations in such manner and at such times as OIPC considers appropriate and thereafter will be accounted for as required by law.

(e) Other Legal Rights. Before and After Default. OIPC will have in addition to the rights specifically provided in this Agreement, the rights of a secured party under the PPSA, as well as the rights recognized at law and in equity. No right will be exclusive of or dependent upon or merge in any other right, and one or more of such rights may be exercised independently or in combination from time to time.

(f) Deficiency. The Borrower will remain liable to OIPC for payment of any obligations under the Financing Agreement that are outstanding following realization of all or any part of the Collateral.

12. OIPC NOT LIABLE

OIPC will not be liable to the Borrower or any other Person for any failure or delay in exercising any of its rights under this Agreement (including among other things any failure to take possession of, collect, or sell, lease or otherwise dispose of any Collateral). None of OIPC, a Receiver or any agent of OIPC is required to take, or will have any liability for any failure to take or delay in taking, any steps necessary or advisable to preserve rights against other Persons under any Chattel Paper, Securities or Instrument in possession of OIPC, a Receiver or OIPC's agent.

13. CHARGES AND EXPENSES

The Borrower agrees to pay on demand all costs and expenses incurred (including among other things legal fees on a solicitor and client basis) and fees charged by OIPC in connection with obtaining or discharging this Agreement or establishing or confirming the priority of the Charges created by this Agreement or by law, compliance with any demand by any Person under the PPSA to amend or discharge any registration relating to this Agreement, and by OIPC or any Receiver in exercising any remedy under this Agreement (including among other things, repairing, processing, preparing for disposition and disposing of the Collateral by sale, lease or otherwise) and in carrying on the Borrower's business. All such amounts will bear interest from time to time at the highest interest rate then applicable to any of the Obligations, and the Borrower will reimburse OIPC upon demand for any amount so paid.

14. FURTHER ASSURANCES

The Borrower will from time to time immediately upon request by OIPC take such action (including among other things the signing and delivery of financing statements and financing change statements, other schedules, documents or listings describing property included in the Collateral, further assignments and other documents, and the registration of this Agreement) as OIPC may require in connection with the Collateral or as OIPC may consider necessary to give effect to this Agreement. If permitted by law, the Borrower waives the right to sign or receive a copy of any financing statement or financing change statement, or any statement issued by any registry that confirms any registration of a financing statement or financing change statement, relating to this Agreement. The Borrower irrevocably appoints the Senior Vice President, Infrastructure Lending and Chief Financial Officer of OIPC as the Borrower's attorney (with full powers of substitution and delegation) to sign, upon an Event of Default, all documents required to give effect to this section. Nothing in this section affects the right of OIPC as secured party, or any other Person on OIPC's behalf, to sign and file or deliver (as applicable) all such financing statements, financing change statements, notices, verification agreements and other documents relating to the Collateral and this Agreement as OIPC or such other Person considers appropriate.

15. DEALINGS BY OIPC

OIPC may from time to time increase, reduce, discontinue or otherwise vary the Borrower's credit facilities, grant extensions of time and other indulgences, take and give up any Charge, abstain from taking, perfecting or registering any Charge, accept compositions, grant releases and discharges and otherwise deal with the Borrower, Borrowers of the Borrower, guarantors and others, and with the Collateral and any Charges held by OIPC, as OIPC considers appropriate without affecting the Borrowers obligations to OIPC or OIPC's rights under this Agreement.

16. DEFINITIONS IN THIS AGREEMENT

"**Accessions**", "**Account**", "**Chattel Paper**", "**Collateral**", "**Document of Title**", "**Equipment**", "**Goods**", "**Instrument**", "**Intangible**", "**Inventory**", "**Proceeds**", "**Purchase-Money Security Interest**" and "**Security Interest**" have the respective meanings given to them in the PPSA.
"**Books and Records**" means all books, records, files, papers, disks, documents and other repositories of data recording, evidencing or relating to the Collateral to which the Borrower (or any Person on the Borrower's behalf) has access.

"**Charge**" means any mortgage, charge, pledge, hypothecation, lien (statutory or otherwise), assignment, financial lease, title retention-agreement or arrangement, security interest or other encumbrance of any nature however arising, or any other security agreement or arrangement creating in favour of any creditor a right in respect of a particular property that is or could be prior to the right of any other creditor in respect of such property.

"**Consumer Goods**" has the meaning given to it in the PPSA.

"**Event of Default**" has the meaning set out in subsection 11(1).

"**Obligations**" means all present and future indebtedness and liability of every kind, nature and description (whether direct or indirect, joint or several, absolute or contingent, matured or unmatured) of the Borrower to OIPC, wherever and however incurred and any unpaid balance thereof, including, without limitation, under or in respect of the Financing Agreement.

"**Money**" has the meaning given to it in the PPSA or, if there is no such definition, means a medium of exchange authorized or adopted by the Parliament of Canada as part of the currency of Canada, or by a foreign government as part of its currency

"**Person**" means any natural person or artificial body (including among others any firm, corporation or government).

"**Personal Property**" means personal property and includes among other things Inventory, Equipment, Receivables, Books and Records, Chattel Paper, Goods, Documents of Title, Instruments, Intangibles (including intellectual property), Money and Securities, and includes all Accessions to such property.

"**Place of Business**" means a location where the Borrower carries on business or where any of the Collateral is located (including any location described in Schedule AA).

"**PPSA**" means the *Personal Property Security Act, 1990* (Ontario), as such legislation may be amended, renamed or replaced from time to time (and includes all regulations from time to time made under such legislation).

"**Receivables**" means all debts, claims and choses in action (including among other things Accounts and Chattel Paper) - now or in the future due or owing to or owned by the Borrower.

"**Receiver**" means a receiver or a receiver and manager.

"**Securities**" has the meaning given to it in the PPSA or, if there is no such definition and the PPSA defines "security" instead, it means the plural of that term.

"**Serial Number**" means the number that the Person who manufactured or constructed a Serial Number Good permanently marked or attached to it for identification purposes or, if applicable such other number as the PPSA stipulates as the serial number or vehicle information number to be used for registration purposes of such Serial Number Good.

"**Serial Number Good**" means a motor vehicle, trailer, mobile home, aircraft airframe, aircraft engine or aircraft propeller, boat or an outboard motor for a boat.

17. GENERAL

(a) Reservation of the Last Day of any Lease. The Charges created by this Agreement do not extend to the last day of the term of any lease or agreement for lease; however, the Borrower will hold such last day in trust for OIPC and, upon the exercise by OIPC of any of its rights under this Agreement following Default, will assign such last day as directed by OIPC.

(b) Attachment of Security Interest. The Security Interests created by this Agreement are intended to attach (i) to existing Collateral when the Borrower signs this Agreement, and (ii) to Collateral subsequently acquired by the Borrower, immediately upon the Borrower acquiring any rights in such Collateral. The parties do not intend to postpone the attachment of any Security Interest created by this Agreement.

(c) Purchase-Money Security Interest. If OIPC gives value for the purpose of enabling the Borrower to acquire rights in or to any of the Collateral, the Borrower will in fact apply such value to acquire those rights (and will provide OIPC with such evidence in this regard as OIPC may require), and the Borrower grants to OIPC, and OIPC takes, a Purchase-Money Security Interest in such Collateral to the extent that the value is applied to acquire such rights. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the amount of any such value.

(d) Entire Agreement. OIPC has not made any representation or undertaken any obligation in connection with the subject matter of this Agreement other than as specifically set out in this Agreement, and in particular nothing contained in this Agreement will require OIPC to make, renew or extend the time for payment of any loan or other credit accommodation to the Borrower or any other Person.

(e) Additional Security. The Charges created by this Agreement are in addition and without prejudice to any other Charge now or later held by OIPC. No Charge held by OIPC will be exclusive of or dependent upon or merge in any other Charge, and OIPC may exercise its rights under such Charges independently or in combination.

(f) Severability: Headings. Any provision of this Agreement that is void or unenforceable in any jurisdiction is, as to that jurisdiction, ineffective to that extent without invalidating the remaining provisions of this Agreement. The headings in this Agreement are for convenience only and do not limit or extend the provisions of this Agreement.

(g) Interpretation. When the context so requires, the singular will be read as the plural, and vice versa.

(h) Copy of Agreement. The Borrower acknowledges receipt of a copy of this Agreement.

(i) Notice. OIPC may send to the Borrower, by prepaid regular mail addressed to the Borrower at the Borrower's address last known to OIPC, copies of any document required by the PPSA to be delivered by OIPC to the Borrower. Any document mailed in this manner will be deemed to have been received by the Borrower upon the earlier of actual receipt by the Borrower and the expiry of 10 days after the mailing date. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the mailing date.

(j) Enurement; Assignment. This Agreement will enure to the benefit of and be binding upon (i) OIPC, its successors and assigns, and (ii) the Borrower and the Borrower's heirs, executors, administrators, successors and permitted assigns. The Borrower will not assign this Agreement without OIPC's prior written consent.

Schedule "AA"

The following are the Places of Business:

1. 84 Market Street, P.O. Box 308, Brantford, OntarioN3T 5N8

SCHEDULE "F"

SUBORDINATION AND POSTPONEMENT AGREEMENT

TO: **ONTARIO INFRASTRUCTURE PROJECTS CORPORATION**
777 Bay Street, 9th Floor, Toronto, Ontario, M5G 2C8

WHEREAS, pursuant to the terms of a financing agreements in the loan amount of $7,938,000.00, dated as of November 18, 2009 ("**Financing Agreement**") entered into between Brantford Power Inc. ("**BPI**") and the Ontario Infrastructure Projects Corporation ("**Infrastructure Ontario**"), Infrastructure Ontario has established credit facilities in favour of BPI;

AND WHEREAS the Royal Bank of Canada, a secured creditor of BPI, has established four (4) credit facilities, as more particularly described in the Financing Agreement, with BPI under which BPI has granted the Royal Bank of Canada a first ranking General Security Agreement over the personal property of BPI which has been duly registered in Ontario under the *Personal Property Security Act* (Ontario) and the particulars of such registration are set out in Schedule "A" hereto ("**Royal Bank's Security Interest**");

AND WHEREAS BPI has granted a security interest in its personal property in favour of the Corporation of the City of Brantford ("**City of Brantford**") , another secured creditor of BPI, with respect to a promissory note issued to the City of Brantford in the amount of $24,181,168.00, which has been duly registered in Ontario under the *Personal Property Security Act* (Ontario) and the particulars of such registration are set out in Schedule "A" hereto ("**City of Brantford's Security Interest**");

AND WHEREAS BPI has granted a security interest in its personal property in favour of Infrastructure Ontario with respect to the credit facility set up under the Financing Agreement and the particulars of such registration are set out in Schedule "A" hereto ("**Infrastructure Ontario's Security Interest**");

AND WHEREAS Infrastructure Ontario, as a condition of the Financing Agreement, requires that the City of Brantford's Security Interest be subordinated and postponed in favour of Infrastructure Ontario so that it may have a second ranking General Security Agreement over the personal property of BPI, ranking only behind the Royal Bank's Security Interest;

AND WHEREAS the City of Brantford directly or indirectly is also a shareholder of BPI;

NOW THEREFORE, for good and valuable consideration, the City of Brantford hereby covenants to and for the benefit of Infrastructure Ontario as follows:

1. The City of Brantford's Security Interest is hereby subordinated and postponed to and in favour of Infrastructure Ontario's Security Interest,

notwithstanding that any of Infrastructure Ontario's Security Interest shall be defective, unperfected, void or unenforceable for any reason whatsoever.

2. In order to effectuate this Agreement the City of Brantford undertakes and agrees to provide such further and other assurances as may be required by Infrastructure Ontario to give effect to this Subordination and Postponement.

3. Except with the prior written consent of Infrastructure Ontario, the City of Brantford shall not assign the City of Brantford's Security Interest or any part thereof to any other party.

4. The City of Brantford hereby authorizes and directs Infrastructure Ontario, and its solicitors, to register this Subordination and Postponement under the *Personal Property Security Act* (Ontario) and this shall be Infrastructure Ontario's good and sufficient authority for so doing.

5. This Subordination and Postponement Agreement shall be effective April 1, 2010.

6. This Agreement shall enure to the benefit of Infrastructure Ontario, its heirs, executors, administrators, successors and assigns and shall be binding upon the City of Brantford and its heirs, executors, administrators, successors and assigns.

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

IN WITNESS WHEREOF the City of Brantford has executed this Agreement as of the 18^{th} day of November, 2009.

[THE REST OF THIS PAGE IS INTENTIONALLY LEFT BLANK]

THE CORPORATION OF THE CITY OF BRANTFORD

By:

Name: ____
Title:

I have authority to bind the Corporation.

By: ____
Name:
Title:

I have authority to bind the Corporation.
[Affix Corporate Seal]

SCHEDULE "A"

PPSA (ONTARIO) REGISTRATION PARTICULARS

1. **Royal Bank's Security Interest**

   File No. 872012682

   Registration No. 20010502 1444 1530 6849

2. **City of Brantford's Security Interest**

   File No. 866985273

   Registration No. 20001025 1745 8028 0154

3. **Infrastructure Ontario's Security Interest**

   File No. 657678285

   Registration No. 20091118163818620042

ACKNOWLEDGEMENT

TO: **ONTARIO INFRASTRUCTURE PROJECTS CORPORATION**
777 Bay Street, 9th Floor, Toronto, Ontario, M5G 2C8

The undersigned acknowledges receipt of notice in writing of the Subordination and Postponement Agreement dated and effective the 18th day of November, 2009 between Ontario Infrastructure Projects Corporation and the Corporation of the City of Brantford and agrees to the terms thereof.

Dated and effective this 18th day of November, 2009.

BRANTFORD POWER INC.

By: ____________________________
Name:
Title:

I have authority to bind the Corporation.

By: ____________________________
Name:
Title:

I have authority to bind the Corporation.
[Affix Corporate Seal]

Schedule "B"

[Insert Financing Schedule]

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2009/2010**

Date: **Sep 11, 2009**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$10,338,000.00**

Please review, complete areas where indicated, sign, date and return the form to OIPC. The following information will be incorporated into the OIPC Financing Agreement.

The following lists the project information outlined in your application. Please verify that the project details are correct. You may amend the project completion dates or the total project cost if this information has changed since the application was submitted. Transfers between projects or categories are at OIPC's discretion and require pre-approval.

A Project Details

Project Information							Financing Information					
App ID	Project Name	Category	Start Date (mm/dd/yyyy)	Completion Date (mm/dd/yyyy)	Total Project Cost	OIPC Loan Amount	Project ID	Term	Type	Amount	Application Request Date * (mm/dd/yyyy)	Revised Request Date (mm/dd/yyyy)
9027	2009 General Capital Program	MCOther	1/2/2009	12/31/2009	$10,649,429.00	$4,800,000.00	6287	40 y	Amortizing	$4,800,000.00	12/1/2010	
9027	Smart Meter Project	MCOther	4/1/2009	12/31/2010	$5,538,000.00	$5,538,000.00	6288	15 y	Amortizing	$5,538,000.00	6/30/2010	
					$16,187,429.00	**$10,338,000.00**				**$10,338,000.00**		

* **Please note, debentures are to be purchased after expenditures have been incurred. Please review and adjust the Application Debenture Purchase Date if required ensuring adequate time for the debenture purchase. For further clarifications or questions, please contact Debbie Chen-yin, Loan Operations, Community Loans Management at 416-326-1149.**

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2009/2010**

Date: **Sep 11, 2009**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$10,338,000.00**

B Construction Financing Quarterly Forecast

If you wish to participate in the construction loan program, please indicate the amount of construction financing you require per fiscal quarter and per debenture. A reminder that OIPC provides construction advances based on incurred project expenditures, unless prior approval has been sought.

Project ID	OCT-DEC 2009	JAN-MAR 2010	APR-JUN 2010	JUL-SEP 2010	OCT-DEC 2010	JAN-MAR 2011	APR-JUN 2011	JUL-SEP 2011	OCT-DEC 2011	JAN-MAR 2012
6287	$2,400,000.00									
6288										

Project ID	APR-JUN 2012	JUL-SEP 2012	OCT-DEC 2012	JAN-MAR 2013	APR-JUN 2013	JUL-SEP 2013	OCT-DEC 2013	JAN-MAR 2014	APR-JUN 2014	JUL-SEP 2014
6287										
6288										

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2009/2010**

Date: **Sep 11, 2009**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$10,338,000.00**

C Authorization

I agree that these are the terms for the OIPC loan. I understand that OIPC will use this information to draft the Financing Agreement.

Treasurer **PRINT NAME**	**Signature**	**Date**

DIRECTIONS: Please mail or courier the original signed Financing Schedule to OIPC, 777 Bay Street, 9th Floor, Toronto, ON M5G 2C8

Schedule "C"

[Insert Acknowledgement and Consent]

ACKNOWLEDGEMENT AND CONSENT

TO: **ONTARIO INFRASTRUCTURE PROJECTS CORPORATION** ("OIPC")

RE: **BRANTFORD POWER INC** (the "Debtor")

We are the secured party under certain personal property security registrations made against the Debtor, including those listed in Schedule "A". In this Acknowledgment and Consent, all registrations listed in Schedule "A", whether under the *Personal Property Security Act* (Ontario) (the "PPSA"), *Bank Act* (Canada) or any other legislation dealing with the registration of personal property security, are collectively referred to as the "Registrations".

We acknowledge that on November 18, 2009 we entered into a Subordination and Postponement Agreement (the "Subordination Agreement"), a copy of which is attached hereto in Schedule "B", giving OIPC a second ranking General Security Agreement over the personal property of the Debtor.

We understand that OIPC proposes to increase its loan to the Debtor to the principal amount of $10,338,000.00 pursuant to a Financing Agreement dated November 18, 2009 as amended on November 15, 2010 (the "Financing Agreement"), and that OIPC requires this Acknowledgment and Consent as a condition to the establishment of such credit facilities. To induce OIPC to establish such credit facilities, in consideration of it doing so and for other good and valuable consideration, the receipt and sufficiency of which is acknowledged, we confirm and agree as follows:

1. We consent to OIPC increasing the principal amount of its loan to the Debtor to $10,338,000.00 under the Financing Agreement.

2. We consent that our security interest under the Registrations shall continue to be subordinated and postponed to and in favour of OIPC's security interests.

3. Our Subordination Agreement shall continue to be in force and shall apply to the new loan amount of $10,338,000.00.

4. This Acknowledgment and Consent may be relied upon by OIPC, and its successors and assigns, and shall be binding upon us and our successors and assigns.

DATED this day of November, 2010.

THE CORPORATION OF THE CITY OF BRANTFORD

By: ______________________
Name:
Title:

By: ______________________
Name:
Title:

We have authority to bind the Corporation

[Affix Corporate Seal]

SCHEDULE "A"

1.	Secured Party:	The Corporation of the City of Brantford
	Date of Registration:	October 25, 2000
	Registration Number:	20001025 1745 8028 0154
	Reference File Number:	866985273
	Registration Period:	5
	Collateral Classification:	IEAO
	General Collateral Description:	N/A

SCHEDULE "B"

[Insert Subordination and Postponement Agreement]

SCHEDULE "F"

SUBORDINATION AND POSTPONEMENT AGREEMENT

TO: **ONTARIO INFRASTRUCTURE PROJECTS CORPORATION**
777 Bay Street, 9th Floor, Toronto, Ontario, M5G 2C8

WHEREAS, pursuant to the terms of a financing agreements in the loan amount of $7,938,000.00, dated as of ~~October~~ November 18, 2009 ("**Financing Agreement**") entered into between Brantford Power Inc. ("**BPI**") and the Ontario Infrastructure Projects Corporation ("**Infrastructure Ontario**"), Infrastructure Ontario has established credit facilities in favour of BPI;

AND WHEREAS the Royal Bank of Canada, a secured creditor of BPI, has established four (4) credit facilities, as more particularly described in the Financing Agreement, with BPI under which BPI has granted the Royal Bank of Canada a first ranking General Security Agreement over the personal property of BPI which has been duly registered in Ontario under the *Personal Property Security Act* (Ontario) and the particulars of such registration are set out in Schedule "A" hereto ("**Royal Bank's Security Interest**");

AND WHEREAS BPI has granted a security interest in its personal property in favour of the Corporation of the City of Brantford ("**City of Brantford**") , another secured creditor of BPI, with respect to a promissory note issued to the City of Brantford in the amount of $24,181,168.00, which has been duly registered in Ontario under the *Personal Property Security Act* (Ontario) and the particulars of such registration are set out in Schedule "A" hereto ("**City of Brantford's Security Interest**");

AND WHEREAS BPI has granted a security interest in its personal property in favour of Infrastructure Ontario with respect to the credit facility set up under the Financing Agreement and the particulars of such registration are set out in Schedule "A" hereto ("**Infrastructure Ontario's Security Interest**");

AND WHEREAS Infrastructure Ontario, as a condition of the Financing Agreement, requires that the City of Brantford's Security Interest be subordinated and postponed in favour of Infrastructure Ontario so that it may have a second ranking General Security Agreement over the personal property of BPI, ranking only behind the Royal Bank's Security Interest;

AND WHEREAS the City of Brantford directly or indirectly is also a shareholder of BPI;

NOW THEREFORE, for good and valuable consideration, the City of Brantford hereby covenants to and for the benefit of Infrastructure Ontario as follows:

1. The City of Brantford's Security Interest is hereby subordinated and postponed to and in favour of Infrastructure Ontario's Security Interest,

notwithstanding that any of Infrastructure Ontario's Security Interest shall be defective, unperfected, void or unenforceable for any reason whatsoever.

2. In order to effectuate this Agreement the City of Brantford undertakes and agrees to provide such further and other assurances as may be required by Infrastructure Ontario to give effect to this Subordination and Postponement.

3. Except with the prior written consent of Infrastructure Ontario, the City of Brantford shall not assign the City of Brantford's Security Interest or any part thereof to any other party.

4. The City of Brantford hereby authorizes and directs Infrastructure Ontario, and its solicitors, to register this Subordination and Postponement under the *Personal Property Security Act* (Ontario) and this shall be Infrastructure Ontario's good and sufficient authority for so doing.

5. This Subordination and Postponement Agreement shall be effective January 1, 2010.

6. This Agreement shall enure to the benefit of Infrastructure Ontario, its heirs, executors, administrators, successors and assigns and shall be binding upon the City of Brantford and its heirs, executors, administrators, successors and assigns.

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

IN WITNESS WHEREOF the City of Brantford has executed this Agreement as of the 18th day of ~~October~~ November, 2009.

[THE REST OF THIS PAGE IS INTENTIONALLY LEFT BLANK]

THE CORPORATION OF THE CITY OF BRANTFORD

By:

Name:
Title:

I have authority to bind the Corporation.

By:
Name: DARYL LEE
Title: CITY CLERK

I have authority to bind the Corporation.
[Affix Corporate Seal]

SCHEDULE "A"

PPSA (ONTARIO) REGISTRATION PARTICULARS

1. **Royal Bank's Security Interest**

   File No. 872012682

   Registration No. 20010502 1444 1530 6849

2. **City of Brantford's Security Interest**

   File No. 866985273

   Registration No. 20001025 1745 8028 0154

3. **Infrastructure Ontario's Security Interest**

   File No. ■ 657678285

   Registration No. ■ 2009 1118 16381 862 0042

Brantford Power Inc.

Notice of Indirect Collection of Personal Information

The undersigned acknowledges that the Corporation is required to file with the Ontario Securities Commission ("OSC") a report setting out the undersigned' name, address and telephone number, the number and type of securities issued, the date of issuance and the purchase price of the securities issued to the undersigned. Such information is collected indirectly by the OSC under the authority granted to it in securities legislation, for the purposes of the administration and enforcement of the securities legislation of Ontario.

By signing this document, the undersigned hereby authorizes the indirect collection of the foregoing information by the OSC.

The following official can answer questions about the OSC's indirect collection of information:

> Administrative Assistant to the Director of Corporate Finance
> Suite 903, Box 5520 Queen Street West
> Toronto, Ontario M5H 3S8
>
> Telephone: (416) 593-8086
> Facsimile: (416) 593-8252

Dated as of the 3rd day of December, 2007.

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

by Bill Ralph

Name: Bill Ralph
Title: Senior Vice President, Business Development and Corporate Services

I have authority to bind the Corporation

::ODMA\PCDOCS\TOR01\3696135\1

FINANCING AGREEMENT

THIS AGREEMENT ("the Agreement"), made in duplicate, dated and effective as of December 3, 2007

BETWEEN:

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

(herein after referred to as "OIPC");

and

BRANTFORD POWER INC.

(an Ontario corporation created under the *Business Corporations Act* herein after referred to as the "Borrower")

WHEREAS:

OIPC has advised the Borrower that its loan application number 7079, (the "Application") has been approved;

OIPC agrees to make financing available to the Borrower up to a maximum aggregate principal amount of $2,420,000.00 (TWO MILLION, FOUR HUNDRED TWENTY THOUSAND DOLLARS) (the "Committed Amount") for the projects listed in the Application and more particularly described in Schedule "A" hereto (the "Project"), subject to the terms and conditions set out in this Agreement.

NOW THEREFORE in consideration of the covenants of each of the parties contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties, the Borrower and OIPC hereby agree as follows:

1. Definitions

In this Agreement:

(a) "**Acquired Assets**" means any assets, rights or properties, of any nature or kind, acquired, constructed or improved by the Borrower or any Related Entity after the date of this Agreement and, for greater certainty, shall include any buildings or other fixtures, acquired, constructed or improved by the Borrower after the date of this Agreement.

(b) "**Advance**" means a short-term loan made by OIPC to the Borrower in Canadian dollars pursuant to the terms and conditions of this Agreement.

(c) "**Advance Date**" has the meaning given to it in paragraph 6(a) hereof.

(d) "**Advance Interest Rate**" has the meaning given to it in paragraph 9(a) hereof.

(e) "**Agreement**" means the agreement constituted by this agreement including all attached schedules and referenced documents including the debenture(s) and the General Security Agreement and the respective terms and conditions thereunder, as the same may be amended, restated, modified or replaced from time to time. Terms such as "hereof", "herein" and "hereto" refer to this Agreement.

(f) "**Applicable Law**" means, in respect of any Person, property, transaction or event, all present or future applicable laws, statutes, regulations, treaties, judgments and decrees and all present or future applicable published directives, rules, policy statements, instruments and orders of any Public Authority and all applicable orders and decrees of courts and arbitrators of like application.

(g) "**Application**" has the meaning given to it in the first recital hereof.

(h) "**Authorized Officer**" means with respect to the Borrower, the Chief Executive Officer, Chief Financial Officer, Board Secretary, Director or any other officer or Person designated from time to time by a resolution of the Board of Directors of the Borrower.

(i) "**Business Day**" means a day on which banking institutions in Toronto, Ontario, Canada are not authorized or obligated by law or executive order to be closed, other than Saturday or Sunday.

(j) "**Capital Lease Obligation**" means, in respect of any Person, the obligation of such Person, as lessee, to pay rent or other payment amounts under a lease of real or personal property which is required to be classified and accounted for as a capital lease or liability of such Person, in accordance with GAAP.

(k) "**Committed Amount**" has the meaning given to it in the second recital hereof.

(l) "**Debt to Equity Ratio**" means, in respect of the Borrower, on a consolidated basis, at any time, the amount determined in accordance with the formula **D/EQ** where:

(i) "**D**" is the Debt of the Borrower; and

(ii) "**EQ**" is the Equity of the Borrower, including the book value, preferred and common shares, contributed surpluses and retained earnings.

(m) "**Debt Service Coverage Ratio**" means, in respect of the Borrower, on a consolidated basis, at any time, the amount determined in accordance with the formula **DSCR = EBITDA / DSR** where:

(i) "**DSCR**" is the Debt Service Coverage Ratio which means the ability of cash from operations to cover debt service requirements of interest and principal;

(ii) "**EBITDA**" means, for the Borrower, and according to the last audited financial statements of the Borrower, the net income (or, as the case may be, net loss) of the Borrower and its Related Entities determined in accordance with GAAP increased by the sum of, without duplication, (a) interest charges, (b) the aggregate of all taxes (including deferred taxes) based on the income of the Borrower and its Related Entities for such period determined in accordance with GAAP; and (c) the aggregate of all depreciation, amortization and other like reductions to income of the Borrower and its Related Entities not involving or requiring an outlay of cash for such period determined in accordance with GAAP; and

(iii) "**DSR**" means debt service requirements of the Borrower including scheduled payments of interest and principal as required by the debt(s).

(n) "**Debentures**" means secured debentures of the Borrower issued from time to time pursuant to the terms and conditions of this Agreement.

(o) "**Debenture Interest Rate**" has the meaning given to it in paragraph 11(e) hereof.

(p) "**Debenture Purchase Certificate**" means a certificate substantially in the form as provided by OIPC to the Borrower.

(q) "**Debenture Purchase Date**" has the meaning given to it in paragraph 10(a) hereof.

(r) "**Drawdown Certificate**" means a certificate substantially in the form as provided by OIPC to the Borrower.

(s) "**Eligible Borrower**" means a public body that is eligible to borrow from OIPC pursuant to the *Ontario Infrastructure Projects Corporation Act, 2006* (Ontario).

(t) "**Event of Default**" means any of the events described in paragraph 13(c).

(u) "**Facility Termination Date**" means the earlier of December 3, 2012 and the date on which the obligations of OIPC hereunder have been terminated pursuant to paragraphs 13(b) or 13(c) hereof.

(v) "**Financial Instrument Obligations**" means all obligations and liabilities of the Borrower or a Related Entity under or in respect of any interest or currency rate swap, forward agreement or other instrument which is a financial derivative.

(w) "**Fiscal Year**" means the fiscal year of the Borrower ending on December 31st in each calendar year.

(x) "**GAAP**" means the generally accepted accounting principles stated from time to time in the Handbook of the Canadian Institute of Chartered Accountants.

(y) "**Indebtedness**" means, at any time and in respect of any Person, without duplication:

(i) all obligations of such Person for money borrowed including:

(A) obligations with respect to bankers' acceptances;

(B) contingent reimbursement obligations with respect to letters of credit and other financial instruments; and

(C) all Purchase Money Obligations which would be indebtedness under GAAP but excluding, for greater certainty, trade indebtedness accounted for as accounts payable, accrued expenses and other similar current liabilities incurred in the ordinary course of operations determined in accordance with GAAP;

(ii) any Capital Lease Obligation of such Person; and

(iii) all undertakings of such Person in respect of obligations of any Person of the type described in (i) which such Person has guaranteed, directly or indirectly, or the holder of which such Person has otherwise assured against loss thereon.

(z) "**Interest Period**" for an Advance means: (i) initially, the period from and including the date of the Advance to but excluding the next following Reset Date; and (ii) subsequently, each period from and including a Reset Date to but excluding the next following Reset Date.

(aa) "**Issue Date**" for a Debenture means the date on which the Debenture is issued.

(bb) "**Lien**" means any mortgage, hypothec, lien, pledge, assignment, charge, security interest, title retention agreement intended as security, or other similar encumbrance and any other arrangement which has the effect of granting security.

(cc) "**Limited Recourse Debt**" means Indebtedness, under which recourse in respect of a default in the repayment of such Indebtedness is limited to the asset or assets acquired with such Indebtedness by the Borrower or any Related Entity.

(dd) "**Material Related Entity**" means, at any relevant time, any Related Entity, the book value of whose assets, rights and properties constitutes in excess of 10% of the book value of the assets, rights and properties of the Borrower and all its Related Entities, considered as a whole.

(ee) "**Maturity Date**" has the meaning given to it in paragraph 11(a) hereof.

(ff) "**Obligations**" means the amount of all Advances provided to the Borrower pursuant to this Agreement and any unpaid interest thereon.

(gg) "**Officer's Certificate**" means a certificate of the Borrower that has been signed by an Authorized Officer.

(hh) "**Operating Line of Credit**" means a credit facility funding the day-to-day operating requirements of the Borrower and does not include use for long-term capital investments.

(ii) "**Permitted Liens**" means and refers to:

> (i) Liens to which any Acquired Assets are subject at the time such Acquired Assets are acquired by the Borrower or any Related Entity provided that such Lien is limited to the Acquired Assets and such Lien has not been created or incurred in anticipation of such acquisition;
>
> (ii) any Lien on or against cash or marketable debt securities to secure Financial Instrument Obligations incurred by the Borrower or any Related Entity in the course of its operations and not for speculative purposes;
>
> (iii) any Lien in respect of a Purchase Money Obligation, Capital Lease Obligation or Limited Recourse Debt incurred in connection with or within 180 days of the acquisition, construction or improvement of any Acquired Assets and which secures the purchase price of such asset or the cost of acquiring, constructing or improving such asset provided that the amount secured by such Lien does not exceed the purchase price or cost of acquiring, constructing or improving such asset (including any applicable interest and/or lease payments to be paid);
>
> (iv) any Liens to which assets acquired or which are deemed to have been acquired by the Borrower or any Related Entity pursuant to a merger or other combination with any other entity are subject at the time of such merger or other combination;

(v) Liens for Taxes, utility charges, levies, assessments or governmental charges:

 (A) not at such time past due; or

 (B) the validity of which are being contested in good faith and by appropriate proceedings;

(vi) the Lien of any judgment rendered, or claim filed, which is being contested in good faith and by appropriate proceedings;

(vii) undetermined or inchoate Liens and charges incidental to, purchases of goods, construction, maintenance or current operations which have not at such time been filed or registered pursuant to law, which relate to obligations which are at such time not past due or which, if filed or registered, are being contested in good faith and by appropriate proceedings;

(viii) easements, rights-of-way, servitudes or other similar rights in property (including rights-of-way and servitudes for railways, sewers, drains, gas and oil pipe lines, gas and water mains, electric light and power and telephone or telegraph or cable television conduits, poles, wires and cables) granted to or reserved or taken by other Persons;

(ix) security given to a public utility or any municipality or governmental or other public authority when and to the extent required by such utility or municipality or other authority in the ordinary course of operations of the Borrower or any Related Entity and not in connection with the borrowing of money or the obtaining of credit by the Borrower or any Related Entity;

(x) the right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, license, franchise, grant or permit, or by any statutory provision, to terminate any such lease, license, franchise, grant or permit, or to require annual or other periodic payments as a condition of the continuance thereof;

(xi) the reservation in any original grant from the Crown of any land or interests therein and statutory exceptions to title;

(xii) Liens created or assumed by the Borrower or any Related Entity if an Authorized Officer has certified to OIPC that such Liens secure amounts which are not material having regard to the then current market value of the assets, rights and properties of the Borrower and its Related Entities, considered as a whole;

(xiii) any renewal, replacement or temporal extension (or successive renewals, replacements or extensions) in whole or in part of any Permitted Lien so long as the principal amount secured by such Permitted Lien does not exceed the principal amount secured by the Permitted Lien immediately prior to such extension;

(xiv) any and all Liens, whether direct or indirect, contingent or otherwise, to which any of the assets, rights and properties of the Borrower and its Related Entities are subject on the date of this Agreement; and

(xv) Liens or any rights of distress reserved in or exercisable under any lease for rent and for compliance with the terms of such lease.

(jj) "**Person**" includes an individual, firm, partnership, trust, trustee, executor, administrator, legal personal representative, government, governmental body or authority, corporation or other incorporated or unincorporated entity.

(kk) "**Prime Rate**" means, on any day, the annual rate of interest which is the arithmetic mean of the prime rates announced from time to time by the Reference Banks as their reference rates in effect on such day for Canadian dollar commercial loans made in Canada. If fewer than five of the Reference Banks quote a prime rate on such days, the "Prime Rate" shall be the arithmetic mean of the rates quoted by the remaining Reference Banks.

(ll) "**Principal Amount**" of an interest-bearing Debenture means the amount stated to be payable at maturity, exclusive of any interest.

(mm) "**Project**" has the meaning given to it in the second recital hereof.

(nn) "**Public Authority**" means any governmental, regional, municipal or local body having authority over either of the parties.

(oo) "**Purchase Money Obligation**" means any unpaid part of, or indebtedness incurred or assumed for the purpose of acquiring, a particular asset, right or property, the repayment of which is secured by recourse against such asset, right or property.

(pp) "**Reference Banks**" means, collectively, The Toronto-Dominion Bank, Bank of Nova Scotia, Bank of Montreal, Royal Bank of Canada and Canadian Imperial Bank of Commerce.

(qq) "**Related Entity**" means any company, corporation, partnership or other entity which is controlled by the Borrower either through the ownership of voting securities, by contract or otherwise.

(rr) "**Reset Date**" has the meaning given to it in paragraph 9(a) hereof.

(ss) "**Successor Entity**" has the meaning given to it in paragraph 14 hereof.

(tt) "**Taxes**" means any present or future income, excise, stamp, capital, goods and services, property or other taxes, levies or withholding imposed by any taxing authority.

2. Representations and Warranties

The Borrower represents and warrants to OIPC that:

(a) the information contained in the Application, to the extent that it relates to the Borrower or the Project, is true and correct in all material respects as of the date of this Agreement;

(b) the Borrower has been duly incorporated pursuant to Section 142 of the *Electricity Act, 1998* (Ontario) as amended, all of the shares of the Borrower are held by one or more municipal corporations and the Borrower is in the business of distributing electricity and has the corporate power and capacity to:

(i) own, lease and operate its properties and assets and to carry on its activities as distributor of electricity;

(ii) to borrow money;

(iii) to complete the Project; and

(iv) to execute and deliver this Agreement and to perform its obligations hereunder;

(c) the Borrower has taken all necessary corporate action to authorize the execution, delivery and performance of this Agreement;

(d) the Agreement has been duly authorized, executed and delivered by the Borrower and constitutes a valid and legally binding obligation, enforceable against the Borrower in accordance with its respective terms, subject to applicable bankruptcy, insolvency and other laws affecting the enforcement of creditors' rights generally;

(e) the execution and delivery by the Borrower of this Agreement and the performance by the Borrower of its obligations hereunder do not violate, result in a breach of, or constitute a default under:

(i) any of the terms, conditions or provisions of its constating documents or by laws of the Borrower;

(ii) any resolution of the Board of Directors or any financial plan, budget, borrowing strategy or investment strategy of the Borrower; or

(iii) any statute, regulation or other law applicable to the Borrower;

(f) the Borrower is not currently in default under any Indebtedness and undertakes to immediately inform OIPC if it receives any notice of default under any Indebtedness at any time; and

(g) to the best of the Borrower's knowledge, subject only to minor title defects not individually or in the aggregate material nor materially and adversely affecting the use thereof and subject to any security granted to OIPC pursuant to the provisions hereof, the Borrower has good and marketable title to its real and personal properties.

The representations and warranties set out in this paragraph 2 shall survive the execution and delivery of this Agreement and the making of any Advances to the Borrower, notwithstanding any investigations or examinations which may be made by OIPC or any counsel to it.

3. Covenants

The Borrower covenants and agrees with OIPC that, unless OIPC otherwise consents in writing, so long as any Advance is outstanding:

(a) the proceeds of all Advances provided by OIPC to the Borrower shall be applied only to capital expenditures in respect of hard and soft capital costs actually incurred or to be incurred by the Borrower if such costs and expenditures are directly related to the Project and not for any other purpose;

(b) the proceeds of each Debenture shall be applied only to either:

(i) repayment of Advances, as more particularly set out in paragraph 11 below; or

(ii) capital expenditures in respect of hard and soft capital costs actually incurred or to be incurred if OIPC in its sole discretion has agreed to purchase a Debenture prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, by the Borrower if such costs and expenditures are directly related to the Project in respect of which the Debenture is being issued; or

(iii) legal costs and expenses directly related to the issue of such Debenture;

and not for any other purpose;

(c) the Borrower shall duly and punctually pay or cause to be paid when due and payable the principal of and interest on all Advances and all other amounts owing in respect of all Advances, in conformity with the terms of this Agreement, and it shall faithfully observe and perform all the conditions, covenants and requirements of this Agreement;

(d) the Borrower will not, nor will it permit any Material Related Entity to, create, assume or suffer to exist any Lien upon the whole or any part of its assets, rights or properties (both real and personal, including licences, franchises, permits and leasehold interests) whether now owned or hereafter acquired if such Lien secures Indebtedness and is a Lien for the benefit of any Person other than the Borrower unless such Lien is a Permitted Lien;

(e) the Borrower will not, nor will it permit any Material Related Entity to, sell, assign or otherwise dispose of any of its assets, rights and properties whether in a single transaction or a series of transactions, other than to the Borrower, unless:

(i) such sale, assignment or other disposition is not material having regard to the assets, rights and properties of the Borrower and the Material Related Entities, taken as a whole or effected in the ordinary course of operations of the Borrower or the Related Material Entities, as applicable;

(ii) the Borrower, concurrent with the completion of such sale, assignment or other disposition, provides OIPC with a certificate of an Authorized Officer to the effect that such Authorized Officer has no reason to believe that, after giving effect to such sale, assignment or other disposition, the Borrower will not be able to meet all of its financial obligations in accordance with their terms; including its obligation to pay principal and interest on the Advances; or

(iii) in the case of a disposition of all or substantially all of its assets, the Borrower complies with paragraph 14 of this Agreement;

(f) the Borrower shall as soon as practicable following the approval thereof by the Borrower and, in any event, within 100 days after the end of each fiscal year of the Borrower, furnish OIPC with such number of copies as OIPC may reasonably request of an annual balance sheet, statement of revenue and expense, statement of changes in net assets, statement of cash flows, prepared in accordance with GAAP as applied to the presentation of financial information of the Borrower and reported on by an independent accountant and independent auditor;

(g) the Borrower shall furnish OIPC as soon as practicable with any other financial reporting information that OIPC may require at its discretion and at any time prepared in accordance with GAAP.

(h) the Borrower will at all times maintain its existence as a body corporate with all necessary approvals to carry on its operations as a municipal corporation that distributes electricity under Applicable Laws and conduct its operations in a proper and efficient manner, and will keep or cause to be kept proper books of account and will take all necessary steps to ensure that its Material Related Entities conduct their operations in a proper and efficient manner and keep or cause to be kept proper books of account;

(i) the Borrower shall maintain in force with reputable insurers insurance with respect to losses of or damage to its assets from such risks, casualties and contingencies and of such types and in such amounts and subject to such deductible amounts as are customary in the case of prudent persons of established reputation engaged in the same or similar businesses with similar assets, and any other form(s) of appropriate insurance that a prudent person in the business of operating a municipal corporation for the purposes of generating, transmitting, distributing or retailing electricity under Applicable Laws would maintain. The Borrower's insurance carriers and policy provisions must be acceptable to OIPC and must remain in effect for the duration of this Agreement. OIPC shall be named as an additional insured on all such insurance policies. The Borrower shall submit certificates of insurance as evidence of the above required insurance to OIPC prior to any Advances pursuant to this Agreement;

(j) the Borrower shall execute and deliver the General Security Agreement in the form provided and attached as Schedule "E" to this Agreement in order to give OIPC a security interest in the present assets of the Borrower as well as those assets acquired subsequent to the effective date of this Agreement;

(k) since the date of incorporation of the Borrower, there has been no development materially adversely affecting the business or financial condition or position of the Borrower or its ability to carry on business as presently conducted or as contemplated hereunder to be conducted;

(l) the Borrower shall submit project management reports to OIPC for Project (the "Reports") pursuant to the attached Schedule "D" to this Agreement; such Reports to be completed to the satisfaction of OIPC;

(m) the Borrower currently has an existing Operating Line of Credit with the Royal Bank of Canada in the amount of $5,900,000 which is secured by a General Security Agreement in favour of the Royal Bank and which shall (1) be considered senior debt to the financing provided by OIPC under this Agreement and (2) be a Permitted Lien;

(n) the Borrower has a promissory note payable to the City of Brantford in the amount of $24,189,168 (bearing an interest rate of 6.25%, due February 2011) which is secured by a General Security Agreement in favour of the City of Brantford and which shall: (1) be considered senior debt to the financing provided by OIPC under this Agreement and (2) be a Permitted Lien;

(o) the Borrower shall seek the approval of OIPC where the resulting Debt to Equity Ratio of the Borrower relating to any new debt issue exceeds 3:1 at any time, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable;

(p) the Borrower shall seek the approval of OIPC, where the resulting Debt Service Coverage Ratio of the Borrower relating to any new debt issue falls below 1.30x at any time, such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable (the line of credit with the Royal Bank of Canada as identified in paragraph (m) above shall be included in this calculation; or

(q) the Borrower shall notify OIPC as soon as practicable after becoming aware of the occurrence of any Event of Default or of the occurrence of any event or circumstance which, after notice or lapse of time, would become an Event of Default.

For greater certainty, OIPC is not responsible for ensuring that the proceeds of Advances and Debentures provided to the Borrower are in fact used in the manner specified in paragraphs 3(a) and 3(b) above.

4. Project Expenditure Requirements

The Borrower shall not request an Advance in respect of the Project hereunder unless expenditures in an amount no less than the amount of the Advance to be allocated to the Project have actually been incurred by the Borrower prior to the date of such request subject to the right of OIPC to waive this requirement at its sole discretion.

5. Evidence of Advances

OIPC shall open and maintain in accordance with its usual practice books of account evidencing all Advances and all other amounts owing by the Borrower to OIPC. OIPC shall enter in the foregoing accounts details of each Advance and of all amounts from time to time owing or paid by the Borrower to OIPC hereunder, the amounts of principal, interest and fees payable from time to time hereunder. The information entered in the foregoing accounts shall constitute, in the absence of manifest error, *prima facie* evidence of the obligations of the Borrower to OIPC hereunder, the date OIPC made each Advance available to the Borrower and the amounts the Borrower has paid from time to time on account of the principal of, interest on and fees related to the Advances.

6. Procedure for Obtaining Advances

(a) The Borrower may request an Advance to be made on either the 1st or the 15th day of any calendar month or the first Business Day following such date if such date is not a Business Day (either of which is defined as the "Advance Date") by delivering to OIPC at the address shown on Schedule "B" hereto no later than five (5) Business Days prior to the Advance Date on which the Advance is required, by courier, electronic transmission or fax, an irrevocable Drawdown Certificate.

(b) The principal amount of all Advances will be tendered to the Borrower by electronic transfer of funds to an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of such deposit.

7. Conditions Precedent to Advances

OIPC shall not make any Advance until each of the following conditions precedent has been satisfied:

(a) OIPC shall have received a Drawdown Certificate in respect of the Advance requested;

(b) at OIPC's discretion, if any issues that were raised in any audit conducted under paragraph 18(a) have been resolved to OIPC's satisfaction and/or OIPC has neither required an audit under paragraph 18(a) nor is such an audit ongoing;

(c) the amount of the requested Advance when added to the aggregate amount of Advances then outstanding in respect of the Project does not exceed the Committed Amount for the Project;

(d) the representations and warranties of the Borrower set out in paragraph 2 hereof shall be true and correct as at the date of the Advance, as evidenced by a Drawdown Certificate;

(e) the Borrower shall not be in material default of any of its obligations under this Agreement as at the date of the Advance, as evidenced by a Drawdown Certificate;

(f) no Event of Default shall have occurred and be continuing;

(g) expenditures on the Project shall have been incurred subject to paragraph 4, as evidenced by a Drawdown Certificate;

(h) a legal opinion from the Borrower's external legal counsel addressed to OIPC and in the form and substance satisfactory to OIPC shall have been delivered to OIPC on or prior to the first Advance made by OIPC; and

(i) at OIPC's discretion, the requested Advance when added to the aggregate amount of all Advances then outstanding does not exceed the Advance requests as noted in Schedule "A" hereto.

8. Conditions Precedent to Debenture Purchases

OIPC shall not purchase any Debenture until each of the following conditions precedent, has been satisfied, subject also to paragraphs 10 and 11:

(a) OIPC shall have received a Debenture Purchase Certificate;

(b) the amount from the proceeds of the Debenture purchase when added to the aggregate amount of Debentures then outstanding in respect of the Project does not exceed the Committed Amount;

(c) the representations and warranties of the Borrower set out in paragraph 2 hereof shall be true and correct as at the date of the Debenture purchase, as evidenced by a Debenture Purchase Certificate;

(d) the Borrower shall not be in material default of any of its obligations under this Agreement as at the date of the Debenture purchase, as evidenced by a Debenture Purchase Certificate;

(e) at OIPC's discretion, if any issues that were raised in any audit conducted under paragraph 18(a) have been resolved to OIPC's satisfaction and/or OIPC has neither required an audit under paragraph 18(a) nor is such an audit ongoing;

(f) no Event of Default shall have occurred and be continuing;

(g) a legal opinion from the Borrower's external legal counsel addressed to OIPC and in the form and substance satisfactory to OIPC shall have been delivered to OIPC; and

(h) expenditures on the Project shall have been incurred or will be incurred if OIPC in its sole discretion has agreed to purchase a Debenture prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, as evidenced by a Debenture Purchase Certificate.

9. Interest on Advances

(a) Each Advance shall bear interest at a floating rate per annum as posted on the OIPC Web site (www.infrastructureontario.ca) (the "Advance Interest Rate"). The Advance Interest Rate for an Advance for the initial Interest Period shall be as posted on the OIPC Web site (www.infrastructureontario.ca) and will be effective on the date of the Advance. The Advance Interest Rate for each subsequent Interest Period shall be reset on the first Business Day of each calendar month (each such Business Day, a "Reset Date") for the following Interest Period as posted on the OIPC Web site (www.infrastructureontario.ca) and will be effective on the Reset Date, which Advance Interest Rate as so reset shall apply to the Advance for such Interest Period until reset again.

(b) Interest accrued during an Interest Period on the principal balance of an Advance outstanding during such Interest Period shall be payable in arrears on the first Business Day of the calendar month following the Interest Period in an amount equal to the product of the Advance Interest Rate in effect during such Interest Period and the principal balance of the Advance outstanding as at the Reset Date for such Interest Period, or in the case of an initial Interest Period the principal balance outstanding on the date of the Advance, multiplied by a fraction, the numerator of which is the number of days in the Interest Period and the denominator of which is 365.

(c) Payments of interest due by the Borrower for any Advance shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement which Schedule forms part of this Agreement, together with such other authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

(d) The Borrower shall pay interest to OIPC on any overdue amount of principal or interest in respect of any Advance, both before and after demand, default, maturity and judgment, at a rate per annum equal to the Prime Rate plus 200 basis points, calculated on a daily basis from the date such amount becomes overdue for so long as such amount remains overdue, and the Borrower shall pay to OIPC any and all costs and losses incurred by OIPC as a result of the payment having been overdue.

(e) For purposes of disclosure pursuant to the *Interest Act* (Canada), the yearly rate of interest which is equivalent to a rate of interest payable in respect of the principal amount of any Advance for any period of less than a year may be determined by multiplying the rate of interest for such period by a fraction, the numerator of which is the actual number of days in a year commencing on and including the first day in such period and ending on but excluding the corresponding day in the next calendar year and the denominator of which is the actual number of days in such period.

10. Purchase of Debentures

(a) Provided that the Borrower is not in default under this Agreement, that all of the conditions precedent listed in paragraph 8 have been satisfied and that none of the events specified in paragraph 13(c) shall have occurred and be continuing, and upon satisfaction of such other usual and customary conditions precedent as OIPC and its legal counsel may reasonably require, and subject to paragraph 11 hereof, OIPC agrees to purchase Debentures from the Borrower on the 1st or 15th of the calendar month next following the debenture purchase date(s) as noted on the attached Schedule "A" and as determined in the sole discretion of OIPC ("Debenture Purchase Date") and/or at a time or times to be determined at the sole discretion of OIPC, on or prior to the Facility Termination Date in an aggregate Principal Amount not to exceed the Committed Amount and subject to the detailed Debenture purchase process to be provided to the Borrower.

(b) The purchase price for any Debenture issued in accordance with paragraph 10(a) shall be satisfied by virtue of and to the extent of the satisfaction of the Obligations effected by such issuance pursuant to paragraph 11(d). Satisfaction of such purchase price by such means shall be deemed to be equivalent for all purposes, to the receipt by the Borrower from OIPC of a sum of money equal to the amount of the Obligations so satisfied. If such purchase price exceeds the amount of the Obligations so satisfied, OIPC shall pay such excess to the Borrower in immediately available funds upon the issue of the Debentures.

(c) If OIPC agrees to purchase a Debenture(s) from the Borrower prior to making any Advance or prior to the expenditure of all or any portion of the Committed Amount on the Project, the Borrower agrees that it will submit an annual report to OIPC, in the form to be provided by OIPC, verifying that all proceeds of such Debenture(s) have been used exclusively for the financing of the Project during the relevant period. The first such report shall be due on the first anniversary of the purchase of the Debenture(s) by OIPC and subsequent reports shall be due annually thereafter on subsequent anniversaries until such time as all the proceeds of such Debenture(s) have been expended.

(d) The purchase price for Debentures, in excess of the principal amount of any outstanding Obligations, will be tendered to the Borrower by electronic transfer of funds to an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of such deposit.

11. Issue of Debentures and Repayment of Advances

(a) Each Advance shall be due and payable in full on the earlier of the Facility Termination Date or the Debenture Purchase Date for the Project for which the Advance was made (the "Maturity Date"), subject to OIPC's right to extend the Maturity Date in its sole discretion. The Borrower shall repay the Advance on the Maturity Date by:

(i) paying an amount equal to the Advance to OIPC in immediately available funds;

(ii) converting the Advance into long term financing by issuing to OIPC one or more Debentures in a principal amount at least equal to the Advance to be repaid; or

(iii) any combination of (i) and (ii).

(b) The Borrower shall notify OIPC at least sixty (60) days in advance of the Debenture Purchase Date as noted on Schedule "A" hereto if the Debenture(s) will not be offered for purchase on such date and the Borrower shall propose another Debenture Purchase Date subject to OIPC's rights under paragraph 10(a) and subject to OIPC's right to reject the new Debenture Purchase Date.

(c) An Advance may be repaid at any time prior to its Maturity Date at the discretion of OIPC and subject to such terms and conditions as may be imposed at OIPC's discretion. The principal amount of any such repaid Advance cannot be subsequently borrowed by the Borrower.

(d) The issuance of Debentures shall satisfy the Obligations then outstanding to the extent of the aggregate Principal Amount of such issuance with the exception that any amount owing for interest on the Obligations on the Issue Date will be payable on the next following Reset Date and will not be added to the aggregate Principal Amount of such issuance. If such aggregate Principal Amount is less than the total amount of the Obligations, then the principal owing on the balance of the Obligations shall be repaid on the Issue Date to the extent of such aggregate Principal Amount and the interest owing on such balance on the Issue Date will be payable on the next following Reset Date, subject to the right of OIPC to permit the Borrower to satisfy the said balance of the Obligations at a later date.

(e) The interest rate for each Debenture (the "Debenture Interest Rate") shall be fixed by OIPC at its discretion at a rate to be effective at the time of issue at an annual rate of interest equal to the rate posted on OIPC's Web site (www.infrastructureontario.ca) applicable to the type and term of the Debenture on the date of issuance of the rate confirmation letter to be sent to the Borrower by OIPC confirming the interest rate to be offered for the Debenture.

(f) Payments of principal and interest due on each Debenture shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OIPC by the execution and delivery of the attached Schedule "C" to this Agreement, together with such other authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OIPC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

12. Security

As continuing collateral security for the payment by the Borrower to OIPC under the terms of this Agreement and for performance by the Borrower of its obligations hereunder, the Borrower acknowledges and agrees that OIPC is to have the benefit of the General Security Agreement as more particularly described in Schedule "E" hereto.

13. Term, Termination and Default

(a) This Agreement shall terminate ten (10) Business Days following the date on which the last Obligations outstanding hereunder are paid in full or following the last payment made by the Borrower to OIPC as specified on the Debenture(s) and/or General Security Agreement pursuant to this Agreement unless earlier terminated in accordance with paragraphs (b) or (c) below.

(b) OIPC may terminate its obligations under this Agreement on thirty (30) days prior notice in writing to the Borrower if in the reasonable opinion of OIPC the Borrower is in material default under this Agreement, other than for any cause enumerated in (c) below or if OIPC rejects a new Debenture Purchase Date pursuant to section 11(b).

(c) OIPC may terminate any or all of its obligations under this Agreement immediately, subject to paragraph (d) below,

(i) if the Borrower:

(A) fails to make one or more payments of principal or interest in respect of any Advance or Debenture within five (5) Business Days after the same becomes due and payable;

(B) reaches or exceeds any updated debt and financial obligation limit imposed by its by-laws or any resolution of the Board of Directors of the Borrower;

(C) has failed to pay principal of or interest on any Indebtedness other than the Advances or Debentures issued under this Agreement when due and such default continues for five (5) Business Days;

(D) has failed to meet and pay any of its liabilities and obligations other than Indebtedness when due and default in payment is occasioned from financial difficulties affecting the Borrower;

(E) uses any Advance or the proceeds of any Debenture financing provided by OIPC for any purpose other than financing the Project;

(F) takes any action to authorize the termination of the existence of the Borrower or a resolution is passed authorizing the termination of the existence of the Borrower, unless such action or resolution is being pursued by the Borrower on the basis that it has made provision for payment of all of its Indebtedness including all of the Advances and Debentures issued under this Agreement, that no court proceedings are pending against it and that it has obtained the approval of its creditors to a plan for the rateable distribution of all of its property; or

(G) is subject to any proceeding whereby such proceeding shall be instituted against the Borrower or applying to a substantial part of its property or assets seeking to adjudicate it a bankrupt or insolvent, or seeking liquidation, dissolution, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or any substantial part of its property or debt under any law relating to bankruptcy, insolvency or reorganization or relief of debts, or seeking an order for relief or the appointment of a receiver, trustee or other similar official for it or for any substantial part of its property and such proceeding shall have continued undismissed or unstayed for sixty (60) days, or a creditor or creditors of the Borrower shall privately appoint a receiver, trustee or similar official for any substantial part of the property of the Borrower and, if the Borrower shall be contesting such appointment in good faith, such appointment shall continue for ninety (90) days; or any such action or proceeding shall have been consented to or not expeditiously opposed by the Borrower;

(ii) if the Borrower shall fail to observe or perform any covenant or condition contained herein and the Borrower shall not make good such default within a period of thirty (30) days after written notice has been given to the Borrower by OIPC;

(iii) if the representations and warranties made by the Borrower in this Agreement and/or the Application, or in any certificate or other document delivered hereunder shall be incorrect in any material respect when made and, if such incorrect representation or warranty is curable, the Borrower shall fail to make good such default within a period of thirty (30) days after notice in writing has been given to the Borrower by OIPC;

(iv) if issues raised in an audit required under paragraph 18(a) have not been resolved to OIPC's satisfaction within a reasonable time after the Borrower has been notified of such issues;

(v) if the report of the auditors on any annual financial statements delivered pursuant to paragraph 3(f) or any other financial information requested by OIPC delivered pursuant to paragraph 3(g) hereof shall be qualified in any way which OIPC acting reasonably deems to be materially adverse or if the Borrower should fail to supply any documents requested pursuant to paragraphs 3(f) and (g);

(vi) if any final judgment is obtained against the Borrower for an amount in excess of $100,000 and, within 10 days of the obtaining thereof, such judgement has not been discharged or execution thereunder stayed; or

(vii) if at any time any licence or approvals required by the Borrower by any Applicable Law or Public Authority to carry on the business of an electricity distributor in Ontario has been assigned, cancelled or suspended;

(viii) if the Borrower shall fail to have obtained the consent required under paragraph 14 (i) below;

(ix) if the Borrower shall enter into any Indebtedness which is senior to any Indebtedness to OIPC, other than pursuant to this Agreement, subsequent to the date of this Agreement without the prior written consent of OIPC; or

(x) if the shares of the Borrower are no longer held exclusively by one or more municipal corporations as further described in paragraph 2(b) above.

(d) If OIPC elects to terminate its obligations under this Agreement pursuant to paragraph 13(c) hereof, it shall give notice in writing of such termination to the Borrower, specifying the reason for such termination. Upon delivery of such notice OIPC shall have no further obligation to make any Advances or to purchase any Debentures hereunder. In such notice OIPC may also declare all Obligations and Debentures outstanding hereunder to be immediately due and payable, whereupon such Obligations and Debentures shall become immediately due and payable pursuant to paragraph 13, in addition to any other rights or remedies that OIPC may have at law or in equity to enforce such Obligations and Debentures.

(e) No delay on the part of OIPC in exercising any remedy and no waiver by OIPC of any of its rights against the Borrower shall operate as a waiver of any other rights nor shall any single or partial exercise of any remedy against the Borrower restrict other or further exercises of such remedy, all remedies being cumulative and not exclusive.

14. Successor Corporations

The Borrower may:

(a) amalgamate, merge, consolidate or otherwise combine pursuant to statute or by private agreement with any other Person, or

(b) sell, lease or otherwise dispose of all or substantially all of its assets, rights and properties, whether in a single transaction or a series of related transactions, to any other Person;

provided, in either case that:

(i) the prior written consent of OIPC is obtained;

(ii) the resulting or acquiring entity (the "Successor Entity") is a body corporate existing and organized under the laws of Canada or any province or territory thereof;

(iii) the Successor Entity is an Eligible Borrower;

(iv) the Successor Entity expressly assumes the due and punctual payment of the principal of, and all interest on all Advances and all other amounts owing hereunder and the performance and observance of all of the covenants and conditions of this Agreement on the part of the Borrower to be performed;

(v) the Successor Entity delivers an opinion acceptable to counsel for OIPC, acting reasonably, to the effect that the Successor Entity has validly assumed such obligations; and

(vi) no Event of Default shall have occurred or be continuing as of the effective date of each such transaction or shall arise as of the effective date of each such transaction and as a result thereof and the Borrower shall have provided OIPC with an Officer's Certificate to such effect.

15. Communications Requirements

(a) OIPC and the Borrower will work together to ensure that OIPC financing of the Project receives recognition and prominence through agreed upon communications activities. An example of such activity could include signage at the project site signifying Government of Ontario project financing.

(b) OIPC reserves the right to undertake its own communications activities in relation to OIPC financing of the Project at anytime in its sole discretion and at its expense.

(c) All joint communications activities between the Borrower and OIPC must comply with the Government of Ontario's Visual Identity Directive and guidelines.

16. Project Management Requirements

As a condition of OIPC making financing available to the Borrower as further described in the second recital hereof, the Borrower shall be required to comply with OIPC's project management reporting requirements for the Project and shall submit the Reports to OIPC pursuant to and as further described in the attached Schedule "D" to this Agreement.

Reports submitted by the Borrower to OIPC are for OIPC's reference only and in no way shall OIPC, its officers, directors, agents, subcontractors, or employees be held responsible or liable at law for: (a) any claim, demand or action brought forward by any party, including third parties, against OIPC; and (b) direct or indirect consequential damages, including bodily injury, death or property damages, arising out of or in any way related to the Reports, this Agreement or the Project.

17. Indemnity

To the fullest extent permitted by law, the Borrower shall indemnify and hold harmless OIPC, its officers, directors, employees and agents (the "Indemnified Parties") from and against all (a) claims and causes of action, pending or threatened, of any kind (whether based in contract, tort or otherwise) by third parties or by whomever made related to or arising out of or in any way related to the Reports, this Agreement or the Project and (b) liabilities, losses, damages, costs and expenses (including, without limitation, legal fees and disbursements) suffered or incurred by any of the Indemnified Parties in connection with any claims or causes of action described in (a) above. The obligations contained in this paragraph shall survive the termination or expiry of this Agreement.

18. General Provisions

(a) OIPC reserves the right to audit compliance with this Agreement at any time. Such right will survive any termination of this Agreement. The cost of any such audit will be at OIPC's expense. The Borrower is required to keep any supporting documents required for any such audit for a minimum of seven (7) years.

(b) No amendment, supplement, restatement or termination of any provision of this Agreement is binding unless it is in writing and signed by each party.

(c) The Borrower may not assign its rights or transfer its obligations under this Agreement without the prior written consent of OIPC. OIPC may assign its rights or transfer its obligations under this Agreement without the prior written consent of the Borrower by giving thirty (30) days notice of such assignment or transfer to the Borrower. This Agreement enures to the benefit of and binds the parties and their respective successors and permitted assigns.

(d) This Agreement, together with the Schedules, the Application, the Drawdown Certificate, the Debenture Purchase Certificate, the Officer's Certificates delivered hereunder, the annual report provided for in paragraph 10(c) hereof, the Debenture(s) and the General Security Agreement and their respective terms and conditions delivered hereunder constitutes the entire agreement between the parties with respect to the subject matter referenced in those documents and supersedes all prior agreements, negotiations, discussions, undertakings, representations, warranties and understandings, whether written or oral.

(e) Each party shall from time to time promptly execute and deliver all further documents and take all further action reasonably necessary or appropriate to give effect to the provisions and intent of this Agreement.

(f) This Agreement is governed by, and is to be construed and interpreted in accordance with, the laws of the Province of Ontario and the federal laws of Canada applicable in the Province of Ontario.

(g) This Agreement and any amendment, supplement, restatement or termination of any provision of this Agreement may be executed and delivered in any number of counterparts, each of which when executed and delivered is an original but all of which taken together constitute one and the same instrument.

(h) Either party may deliver an executed copy of this Agreement by fax but that party shall immediately deliver to the other party an original executed copy of this Agreement.

(i) Unless otherwise specified, each notice to a party must be given in writing and delivered personally or by courier, sent by prepaid registered mail or transmitted by fax to the address or fax number set out in Schedule "B".

(j) If any provision of this Agreement is or becomes illegal, invalid or unenforceable in any jurisdiction, the illegality, invalidity or unenforceability of that provision will not affect:

  (i) the legality, validity or enforceability of the remaining provisions of this Agreement; or

  (ii) the legality, validity or enforceability of that provision in any other jurisdiction.

(k) All covenants, agreements, representations and warranties made herein or in any document delivered pursuant to the provisions hereof are material, shall be deemed to have been relied upon by each party hereto and, notwithstanding any investigation heretofore or hereafter made by such party shall survive the execution and delivery of this agreement until all amounts owing pursuant to the provisions hereof have been paid in full.

(l) Words importing the singular include the plural and vice versa.

IN WITNESS WHEREOF the parties hereto have executed the Agreement effective as of the date first above written.

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

By:
Name: Bill Ralph
Title: Senior Vice President, Business Development and Corporate Services

I have authority to bind the Corporation.

BRANTFORD POWER INC.

By:
Name: Andy Molenaar c/s
Title: Director

I have authority to bind the Corporation.

By:
Name: Heather Wyatt c/s
Title: Board Secretary

SCHEDULE "A"

FINANCING SCHEDULE

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2007/2008**

Date: **Oct 04, 2007**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$2,420,000.00**

Please review, complete areas where indicated, sign, date and return the form to OIPC. The following information will be incorporated into the OIPC Financing Agreement.

The following lists the project information outlined in your application. Please verify that the project details are correct. You may amend the project completion dates or the total project cost if this information has changed since the application was submitted. Transfers between projects or categories are at OIPC's discretion and require pre-approval.

A Project Details

Project Information							Financing Information					
App ID	Project Name	Category	Start Date (mm/dd/yyyy)	Completion Date (mm/dd/yyyy)	Total Project Cost	OIPC Loan Amount	Project ID	Term	Type	Amount	Application Request Date * (mm/dd/yyyy)	Revised Request Date (mm/dd/yyyy)
7079	Electricity Distribution System Capital Program	MCOther	1/2/2007	12/31/2007	$4,176,806.00	$846,000.00	5963	25 y	Amortizing	$846,000.00	1/10/2007	11/15/2007
7079	Voltage Conversion Project	MCOther	1/2/2007	12/31/2007	$1,574,000.00	$1,574,000.00	5964	25 y	Amortizing	$1,574,000.00	1/10/2007	11/15/2007
					$5,750,806.00	$2,420,000.00				$2,420,000.00		

*** Please note, debentures are to be purchased after expenditures have been incurred. Please review and adjust the Application Debenture Purchase Date if required ensuring adequate time for the debenture purchase. For further clarifications or questions, please contact Debbie Chen-yin, Loan Operations, Community Loans Management at 416-326-1149.**

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2007/2008**

Date: **Oct 04, 2007**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$2,420,000.00**

B Construction Financing Quarterly Forecast

If you wish to participate in the construction loan program, please indicate the amount of construction financing you require per fiscal quarter and per debenture. A reminder that OIPC provides construction advances based on incurred project expenditures, unless prior approval has been sought.

Project ID	OCT-DEC 2007	JAN-MAR 2008	APR-JUN 2008	JUL-SEP 2008	OCT-DEC 2008	JAN-MAR 2009	APR-JUN 2009	JUL-SEP 2009	OCT-DEC 2009	JAN-MAR 2010
5963										
5964										

Project ID	APR-JUN 2010	JUL-SEP 2010	OCT-DEC 2010	JAN-MAR 2011	APR-JUN 2011	JUL-SEP 2011	OCT-DEC 2011	JAN-MAR 2012	APR-JUN 2012	JUL-SEP 2012
5963										
5964										

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

Financing Schedule

Program Year: **2007/2008**

Date: **Oct 04, 2007**

Organization Name: **Brantford Power Inc.**

Approved Loan Amount: **$2,420,000.00**

C Authorization

I agree that these are the terms for the OIPC loan. I understand that OIPC will use this information to draft the Financing Agreement.

BRIAN D'Amboise CA		Oct 16 2007
Treasurer **PRINT NAME**	**Signature**	**Date**

DIRECTIONS: Please mail or courier the original signed Financing Schedule to OIPC, 777 Bay Street, 9th Floor, Toronto, ON M5G 2C8

SCHEDULE "B"

ADDRESSES FOR NOTICE

Ontario Infrastructure Projects Corporation
777 Bay Street, 9th Floor
Toronto, Ontario M5G 2C8

Attn: Director, Loans Operations
Tel.: 416-326-1149
Fax: 416-212-6452

Brantford Power Inc.
84 Market Street
P.O. Box 308
Brantford, ON
N3T 5N8

Attn: Brian D'Amboise, CA
Tel.: 519-759-4222 x3234
Fax: 519-759-8129

PRE-AUTHORIZED DEBIT AND ACCOUNT FOR DEPOSIT
BRANTFORD POWER INC.

(1) Account Holder Information

Full Legal Name: BRANTFORD POWER INC.

Exact account name: BRANTFORD POWER INC. WIRES COMPANY

Address: 100 WELLINGTON SQUARE City: BRANTFORD

Province: ON Postal Code: N3T 2M3 Phone #: 519 759-4150

(2) Financial Institution Information (Note: Please attach VOID cheque)

(i) Inflow of Deposits

Name of Financial Institution: ROYAL BANK OF CANADA

Address: 22 COLBORNE ST City: BRANTFORD

Province: ON Postal Code: N3T 2G2 Phone #: 519 758-2056

Transit #: 00522 Institution #: 003 Account #: 100-883-8

(ii) Outflow of Pre-Authorized Debit

- ☒ Same as above
- ☐ If different from above fill out banking information below

Name of Financial Institution: ______

Address: ______ City: ______

Province: ______ Postal Code: ______ Phone #: ______

Transit #: ______ Institution #: ______ Account #: ______

Sample of the numbering at the bottom of a cheque

001234	01234 - 001		111-222-3
⇩	⇙	⇘	⇩
Cheque #	Transit #	Institution #	Account #

(3) **Pre Notification of Amounts**

Fixed Amounts: The Company will provide written notice of the amount to be debited and the date of the debit at least ten (10) calendar days before the date of the first debit and every time there is a change in the amount or payment date.

Variable Amounts: The Company will provide written notice of each amount to be debited and the date of the debit at least ten (10) calendar days before the date of each debit.

The Customer and Company agree to waive the above prenotification requirements.

Authorized Signature of Customer: ______________________
BRANTFORD POWER INC.

Authorized Signature of Customer: ______________________
BRANTFORD POWER INC.

Authorized Signature of Company: ______________________
ONTARIO INFRASTRUCTURE PROJECTS CORPORATION

(4) **Rights of Dispute**

The Customer may dispute a debit under the following conditions: (i) the debit was not drawn in accordance with this Authorization; (ii) this Authorization was revoked or cancelled; or (iii) prenotification (as set out in paragraph 3 above) was not received.

In order to be reimbursed, the Customer must complete a Declaration Form at the above indicated branch of the Bank up to and including ten (10) calendar days, after the date on which the debit in dispute was posted to the Customer's account.

The Customer acknowledges that disputes after the above noted time limitations are matters to be resolved solely between the Company and Customer.

(5) **Terms of Authorization to Debit the Above Account**

The Customer authorizes the Company to debit the above account(s) in the amount of $_________(intentionally left blank)________for payments payable to the Company in respect of its indebtedness to OIPC.

The Bank is not required to verify that any debits drawn by the Company are in accordance with this Authorization or the agreement made between the Customer and the Company.

It is acknowledged that this Authorization cannot be revoked without the express written agreement of the Company. This Authorization applies only to a method of payment and cancellation of this Authorization does not mean that the Customer's contractual obligations to the Company are ended.

The Customer will notify the Company promptly in writing if there is any change in the above account information.

Any delivery of this Authorization to the Company constitutes delivery by the Customer to the Bank. It is warranted by the Customer that all persons whose signatures are required to sign on the above account have signed this Authorization. The Customer acknowledges receipt of a signed copy of this Authorization.

NOVEMBER 30/07

Signature(s) or Authorized Signature(s) of Account Holder(s) (Date)

NOVEMBER 30/07

Signature(s) or Authorized Signature(s) of Account Holder(s) (Date)

::ODMA\PCDOCS\TOR01\3694749\1

See reverse side for security characteristics. Voir au verso pour les caractéristiques de sécurité.

103437

Brantford Power Inc.
Wires Company
100 Wellington Square
Brantford, ON N3T 2M3

Royal Bank of Canada
22 Colborne Street, Brantford, ON

MM DD YYYY

VENDOR NO. CHEQUE NO.

$

PAY
TO THE
ORDER
OF

VOID

M. C. Hamack.
H.Y.

⑆00522⑉003⑆ 100⑉883⑉8⑈

SCHEDULE "D"

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION PROJECT MANAGEMENT AND BEST PRACTICES REPORTING REQUIREMENTS

Construction Reporting

To help ensure effective and efficient delivery of projects financed (in whole or in part) with funds from the OSIFA Loan Program, Ontario Infrastructure Projects Corporation (Infrastructure Ontario) has introduced reporting requirements for all **capital construction projects**. Borrowers are responsible to submit project reports according to the Estimated Project Start Date as indicated in their online application.

Depending on the size of the project, borrowers will be subject to the following requirements.

For projects <u>under</u> $10,000,000, borrowers will:

- Submit standard **quarterly** project management report(s)
- For projects three months in duration or less, only a **final** report is required

For projects <u>over</u> $10,000,000, borrowers will:

- Submit **monthly** project management reports using the Infrastructure Ontario template prior to the end of the second week of each month (for the preceding month)

Please forward all reports to:
Mail: Customer Relations Coordinator
Infrastructure Ontario
777 Bay St., 9th Fl.
Toronto, Ontario M5G 2C8

Email: Customer.Relations@infrastructureontario.ca
Fax: 416-212-6452

For more details on Project Management and Best Practices Reporting, please visit www.infrastructureontario.ca/private/pmr/index.asp.

SCHEDULE "E"

GENERAL SECURITY AGREEMENT

GENERAL SECURITY AGREEMENT

For valuable consideration. the undersigned (the "Borrower") agrees with Ontario Infrastructure Projects Corporation ("OIPC") as follows:

1. GRANT OF SECURITY INTEREST

As general and continuing security for the payment and performance when due of all Obligations, the Borrower hereby mortgages, charges and assigns to OIPC, and grants to OIPC, and OIPC takes, a Security Interest in the property described in the following paragraphs of this section, and in all property described in any schedules, documents or listings that the Borrower may from time to time sign and provide to OIPC in connection with this Agreement, and in all present and future Accessions to, and all Proceeds of, any such property (collectively, the "Collateral") as a general and continuing collateral security for the due payment of the obligations payable under the Financing Agreement (the "Financing Agreement") dated and effective as of December 3, 2007 and made between the Borrower and Ontario Infrastructure Projects Corporation:

(a) **Accounts Receivable**. All debts, book debts, accounts, claims, demands, money and choses in action, including without limitation, all claims against Her Majesty the Queen in right of Canada or any Province (other than Ontario) or Territory and all claims and benefits under any insurance policies;

(b) **Inventory**. All inventory, including, without limitation, all goods, merchandise, raw materials, goods in process, finished goods and other tangible personal property now or hereafter held for sale, lease or resale or that are to be furnished or have been furnished under a contract of service or that are used or consumed in the business of the Borrower;

(c) **Equipment**. All goods which are not inventory or consumer goods, including, without limitation, all fixtures, equipment, machinery, vehicles and other tangible personal property;

(d) **Chattel Paper, Instruments, Securities etc**. All chattel paper, instruments, warehouse receipts, bills of lading and other documents of title, whether negotiable or non-negotiable, shares, stock, warrants, bonds, debentures, debenture stock and other securities;

(e) **Intangibles**. All intangibles, including, without limitation, all contractual rights, goodwill, patents, trade-marks, copyrights, industrial designs and other industrial or intellectual property or rights therein;

(f) **Books and Accounts, etc**. All books, accounts, invoices, letters, papers, writings, certificates, receipts, documents and other records and data in any form or medium evidencing, representing, creating, giving rise to any rights in respect of or otherwise relating to the property described in paragraphs (a) to (e) inclusive; and

(g) **Proceeds**. All property in any form derived directly or indirectly from any dealing with any undertaking or property subject to the Security Interest or that indemnifies or compensates for such undertaking or property being destroyed, damaged, expropriated, stolen or lost and proceeds or proceeds whether of the same type or kind as the original proceeds.

2. GOVERNING LAW

This Agreement is governed by the laws of Ontario.

BRANTFORD POWER INC.

By: ______________________________
Name: Andy Molenaar
Title: Director

I have authority to bind the Corporation.

By: ______________________________
Name: Heather Wyatt c/s
Title: Board Secretary

I have authority to bind the Corporation.

By: ______________________________
Name: c/s
Title:

ADDITIONAL TERMS AND CONDITIONS. THE ADDITIONAL TERMS AND CONDITIONS (INCLUDING ANY SCHEDULES) ON THE FOLLOWING PAGES FORM PART OF THIS AGREEMENT.

The Borrower has signed this Agreement with effect on December 3rd, 2007.

GENERAL SECURITY AGREEMENT
ADDITIONAL TERMS AND CONDITIONS

1. FINANCING AGREEMENT

Reference is hereby expressly made to the Financing Agreement and all instruments supplemental thereto for a statement and description of, among other things, the liability of the Borrower for payment of the Obligations, the terms, conditions, covenants and warranties upon which the Obligations are issued and held, and the rights and remedies of OIPC, all to the same effect as if the provisions of the Financing Agreement were herein set out.

2. PLACES OF BUSINESS

The Borrower represents and warrants that the locations of all existing Places of Business are specified in Schedule "BB". The Borrower will promptly notify OIPC in writing of any additional Places of Business as soon as they are established. Subject to Section 5, the Collateral will at all times be kept at the Places of Business and will not be removed without OIPC's prior written consent.

3. COLLATERAL FREE OF CHARGES

The Borrower represents and warrants that the Collateral is, and agrees that the Collateral will at all times be free, of any Charge or trust except in favour of OIPC or incurred with OIPC's prior written consent. OIPC may, but will not have to, pay any amount or take any action required to remove or redeem any unauthorized Charge. The Borrower will immediately reimburse OIPC for any amount so paid and will indemnify OIPC in respect of any action so taken.

4. USE OF COLLATERAL

The Borrower will not, without OIPC's prior written consent, sell, lease otherwise dispose of any of the Collateral (other than Inventory, which may be sold, leased or otherwise disposed of in the ordinary course of the Borrower's business). All Proceeds of the Collateral (including among other things received in respect of Receivables), whether or not arising in the ordinary course of the Borrower's business, will be received by the Borrower as trustee for OIPC and will be immediately paid to OIPC.

5. INSURANCE

The Borrower will keep the Collateral insured to its full insurable value against loss or damage by fire and such other risks as are customarily insured for property similar to the Collateral (and against such other risks as OIPC may reasonably require). At OIPC's request, all policies in respect of such insurance will contain a loss payable clause in favour of OIPC and in any event the Borrower assigns all proceeds of insurance on the Collateral to OIPC. The Borrower will, from time to time at OIPC's request, deliver such policies (or satisfactory evidence of such policies) to OIPC. If the Borrower does not obtain or maintain such insurance, OIPC may, but will not have to, do so. The Borrower will immediately reimburse OIPC for any amount so paid. The Borrower will promptly give OIPC written notice of any loss or damage to all or any part of the Collateral.

6. INFORMATION AND INSPECTION

The Borrower will from time to time immediately give OIPC in writing all information requested by OIPC relating to the Collateral, the Places of Business, and the Borrower's financial or business affairs. The Borrower will promptly advise OIPC of the Serial Number, model year, make and model of each Serial Number Good at any time included in the Collateral that is held as Equipment, including in circumstances where the Borrower ceases holding such Serial Number Good as Inventory and begins holding it as Equipment. OIPC may from time to time inspect any Books and Records and any Collateral, wherever located. For that purpose OIPC may, without charge, have access to each Place of Business and to all mechanical or electronic equipment, devices and processes where any of them may be stored or from which any of them may be retrieved. The Borrower authorizes any Person holding any Books and Records to make them available to OIPC, in a readable form upon request by OIPC.

7. RECEIVABLES

If the Collateral includes Receivables, OIPC may advise any Person who is liable to make any payment to the Borrower of the existence of this Agreement. OIPC may from time to time confirm with such Persons the existence and the amount of the Receivables. Upon an Event of Default, OIPC may collect and otherwise deal with the Receivables in such manner and upon such terms, as OIPC considers appropriate.

8. RECEIPTS PRIOR TO DEFAULT

Until an Event of Default, all amounts received by OIPC as Proceeds of the Collateral will be applied on account of the Liabilities in such manner and at such times as OIPC may consider appropriate or, at OIPC's option, may be held unappropriated in a collateral account or released to the Borrower.

9. DEFAULT

(1) **Events of Default**. "Event of Default" means any of the events described in paragraph 13(c) of the Financing Agreement. In case an Event of Default shall occur and be continuing, the full unpaid principal amount together with interest accrued thereon of any obligations outstanding payable under the Financing Agreement at the time of the occurrence, may become or be declared due before stated maturity by OIPC.

(2) **Additional Rights upon Default**. Upon the occurrence of any Event of Default, OIPC and a Receiver, as applicable, will to the extent permitted by law have the following additional rights:

(a) <u>Appointment of Receiver</u>. OIPC may by instrument in writing appoint any Person as a Receiver of all or any part of the Collateral. OIPC may from time to time remove or replace a Receiver, or make application to any court of competent jurisdiction for the appointment of a Receiver. Any Receiver appointed by OIPC will (for purposes relating to responsibility for the Receiver's acts or omissions) be considered to be the Borrower's agent. OIPC may from time to time fix the Receiver's remuneration and the Borrower will pay OIPC the amount of such remuneration. OIPC will not be liable to the Borrower or any other Person in connection with appointing or not appointing a Receiver or in connection with the Receiver's actions or omissions.

(b) Dealings with the Collateral. OIPC or a Receiver may take possession of all or any part of the Collateral and retain it for as long as OIPC or the Receiver considers appropriate, receive any rents and profits from the Collateral, carry on (or concur in carrying on) all or any part of the Borrower's business or refrain from doing so, borrow on the security of the Collateral, repair the Collateral, process the Collateral, prepare the Collateral for sale, lease or other disposition, and sell or lease (or concur in selling or leasing) or otherwise dispose of the Collateral on such terms and conditions (including among other things by arrangement providing for deferred payment) as OIPC or the Receiver considers appropriate. OIPC or the Receiver may (without charge and to the exclusion of all other Persons including the Borrower), enter upon any Place of Business.

(c) Realization. OIPC or a Receiver may use, collect, sell, lease or otherwise dispose of, realize upon, release to the Borrower or other Persons and otherwise deal with, the Collateral in such manner, upon such terms (including among other things by arrangement providing for deferred payment) and at such times as OIPC or the Receiver considers appropriate. OIPC or the Receiver may make any sale, lease or other disposition of the Collateral in the name of and on behalf of the Borrower or otherwise.

(d) Application of Proceeds After Default. All Proceeds of Collateral received by OIPC or a Receiver may be applied to discharge or satisfy any expenses (including among other things the Receiver's remuneration and other expenses of enforcing OIPC's rights under this Agreement), Charges, borrowings, taxes and other outgoings affecting the Collateral or which are considered advisable by OIPC or the Receiver to preserve, repair, process, maintain or enhance the Collateral or prepare it for sale, lease or other disposition, or to sell, lease or otherwise dispose of the Collateral. The balance of such Proceeds will be applied to the Obligations in such manner and at such times as OIPC considers appropriate and thereafter will be accounted for as required by law.

(e) Other Legal Rights. Before and After Default. OIPC will have in addition to the rights specifically provided in this Agreement, the rights of a secured party under the PPSA, as well as the rights recognized at law and in equity. No right will be exclusive of or dependent upon or merge in any other right, and one or more of such rights may be exercised independently or in combination from time to time.

(f) Deficiency. The Borrower will remain liable to OIPC for payment of any obligations under the Financing Agreement that are outstanding following realization of all or any part of the Collateral.

10. OIPC NOT LIABLE

OIPC will not be liable to the Borrower or any other Person for any failure or delay in exercising any of its rights under this Agreement (including among other things any failure to take possession of, collect, or sell, lease or otherwise dispose of any Collateral). None of OIPC, a Receiver or any agent of OIPC is required to take, or will have any liability for any failure to take or delay in taking, any steps necessary or advisable to preserve rights against other Persons under any Chattel Paper, Securities or Instrument in possession of OIPC, a Receiver or OIPC's agent.

11. CHARGES AND EXPENSES

The Borrower agrees to pay on demand all costs and expenses incurred (including among other things legal fees on a solicitor and client basis) and fees charged by OIPC in connection with obtaining or discharging this Agreement or establishing or confirming the priority of the Charges created by this Agreement or by law, compliance with any demand by any Person under the PPSA to amend or discharge any registration relating to this Agreement, and by OIPC or any Receiver in exercising any remedy under this Agreement (including among other things presuming, repairing, processing, preparing for disposition and disposing of the Collateral by sale, lease or otherwise) and in carrying on the Borrower's business. All such amounts will bear interest from time to time at the highest interest rate then applicable to any of the Liabilities, and the Borrower will reimburse OIPC upon demand for any amount so paid.

12. FURTHER ASSURANCES

The Borrower will from time to time immediately upon request by OIPC take such action (including among other things the signing and delivery of financing statements and financing change statements, other schedules, documents or listings describing property included in the Collateral, further assignments and other documents, and the registration of this Agreement) as OIPC may require in connection with the Collateral or as OIPC may consider necessary to give effect to this Agreement. If permitted by law, the Borrower waives the right to sign or receive a copy of any financing statement or financing change statement, or any statement issued by any registry that confirms any registration of a financing statement or financing change statement, relating to this Agreement. The Borrower irrevocably appoints the Senior Vice President, Business Development and Corporate Services of OIPC as the Borrower's attorney (with full powers of substitution and delegation) to sign, upon an Event of Default, all documents required to give effect to this section. Nothing in this section affects the right of OIPC as secured party, or any other Person on OIPC's behalf, to sign and file or deliver (as applicable) all such financing statements, financing change statements, notices, verification agreements and other documents relating to the Collateral and this Agreement as OIPC or such other Person considers appropriate.

13. DEALINGS BY OIPC

OIPC may from time to time increase, reduce, discontinue or otherwise vary the Borrower's credit facilities, grant extensions of time and other indulgences, take and give up any Charge, abstain from taking, perfecting or registering any Charge, accept compositions, grant releases and discharges and otherwise deal with the Borrower, Borrowers of the Borrower, guarantors and others, and with the Collateral and any Charges held by OIPC, as OIPC considers appropriate without affecting the Borrowers obligations to OIPC or OIPC's rights under this Agreement.

14. DEFINITIONS IN THIS AGREEMENT

"**Accessions**", "**Account**", "**Chattel Paper**", "**Document of Title**", "**Equipment**", "**Goods**", "**Instrument**", "**Intangible**", "**Inventory**", "**Proceeds**", "**Purchase-Money Security Interest**" and "**Security Interest**" have the respective meanings given to them in the PPSA.

"**Books and Records**" means all books, records, files, papers, disks, documents and other repositories of data recording, evidencing or relating to the Collateral to which the Borrower (or any Person on-the Borrower's behalf) has access.

"**Charge**" means any mortgage, charge, pledge, hypothecation, lien (statutory or otherwise), assignment, financial lease, title retention-agreement or arrangement, security interest or other encumbrance of any nature however arising, or any other security agreement or arrangement creating in favour of any creditor a right in respect of a particular property that is prior to the right of any other creditor in respect of such property.

"**Consumer Goods**" has the meaning given to it in the PPSA.

"**Event of Default**" has the meaning set out in subsection 11(1).

"**Obligations**" means all present and future indebtedness and liability of every kind, nature and description (whether direct or indirect, joint or several, absolute or contingent, matured or unmatured) of the Borrower to OIPC, wherever and however incurred and any unpaid balance thereof, including, without limitation, under or in respect of the Financing Agreement.

"**Money**" has the meaning given to it in the PPSA or, if there is no such definition, means a medium of exchange authorized or adopted by the Parliament of Canada as part of the currency of Canada, or by a foreign government as part or its currency

"**Person**" means any natural person or artificial body (including among others any firm, corporation or government).

"**Personal Property**" means personal property and includes among other things Inventory, Equipment, Receivables, Books and Records, Chattel Paper, Goods, Documents of Title, Instruments, Intangibles (including intellectual property), Money and Securities, and includes all Accessions to such property.

"**Place of Business**" means a location where the Borrower carries on business or where any of the Collateral is located (including any location described in Schedule "BB").

"**PPSA**" means the *Personal Property Security Act, 1990* (Ontario), as such legislation may be amended, renamed or replaced from time to time (and includes all regulations from time to time made under such legislation).

"**Receivables**" means all debts, claims and choses in action (including among other things Accounts and Chattel Paper) - now or in the future due or owing to or owned by the Borrower.

"**Receiver**" means a receiver or a receiver and manager.

"**Securities**" has the meaning given to it in the PPSA or, if there is no such definition and the PPSA defines "security" instead, it means the plural of that term.

"**Serial Number**" means the number that the Person who manufactured or constructed a Serial Number Good permanently marked or attached to it for identification purposes or, if applicable. such other number as the PPSA stipulates as the serial number or vehicle information number to be used for registration purposes of such Serial Number Good.

"**Serial Number Good**" means a motor vehicle, trailer, mobile home, aircraft airframe, aircraft engine or aircraft propeller, boat or an outboard motor for a boat.

15. GENERAL

(a) Reservation of the Last Day of any Lease. The Charges created by this Agreement do not extend to the last day of the term of any lease or agreement for lease; however, the Borrower will hold such last day in trust for OIPC and, upon the exercise by OIPC of any of its rights under this Agreement following Default, will assign such last day as directed by OIPC.

(b) Attachment of Security Interest. The Security Interests created by this Agreement are intended to attach (i) to existing Collateral when the Borrower signs this Agreement, and (ii) to Collateral subsequently acquired by the Borrower, immediately upon the Borrower acquiring any rights in such Collateral. The parties do not intend to postpone the attachment of any Security Interest created by this Agreement.

(c) Purchase-Money Security Interest. If OIPC gives value for the purpose of enabling the Borrower to acquire rights in or to any of the Collateral, the Borrower will in fact apply such value to acquire those rights (and will provide OIPC with such evidence in this regard as OIPC may require), and the Borrower grants to OIPC, and OIPC takes, a Purchase-Money Security Interest in such Collateral to the extent that the value is applied to acquire such rights. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the amount of any such value.

(d) Entire Agreement. OIPC has not made any representation or undertaken any obligation in connection with the subject matter of this Agreement other than as specifically set out in this Agreement, and in particular nothing contained in this Agreement will require OIPC to make, renew or extend the time for payment of any loan or other credit accommodation to the Borrower or any other Person.

(a) Additional Security. The Charges created by this Agreement are in addition and without prejudice to any other Charge now or later held by OIPC. No Charge held by OIPC will be exclusive of or dependent upon or merge in any other Charge, and OIPC may exercise its rights under such Charges independently or in combination.

(b) Severability: Headings. Any provision of this Agreement that is void or unenforceable in any jurisdiction is, as to that jurisdiction, ineffective to that extent without invalidating the remaining provisions of this Agreement. The headings in this Agreement are for convenience only and do not limit or extend the provisions of this Agreement.

(c) Interpretation. When the context so requires, the singular will be read as the plural, and vice versa.

(d) Copy of Agreement. The Borrower acknowledges receipt of a copy of this Agreement.

(e) Notice. OIPC may send to the Borrower, by prepaid regular mail addressed to the Borrower at the Borrower's address last known to OIPC, copies of any document required by the PPSA to be delivered by OIPC to the Borrower. Any document mailed in this manner will be deemed to have been received by the Borrower upon the earlier of actual receipt by the Borrower and the expiry of 10 days after the mailing date. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the mailing date.

(f) Enurement; Assignment. This Agreement will enure to the benefit of and be binding upon (i) OIPC, its successors and assigns, and (ii) the Borrower and the Borrower's heirs, executors, administrators, successors and permitted assigns. The Borrower will not assign this Agreement without OIPC's prior written consent.

SCHEDULE "AA"

The following is a description of property included in the Collateral (describe personal property by item or kind: if space is insufficient (use a separate sheet) :

SCHEDULE "BB"

The following are the Places of Business (if space is insufficient, use a separate sheet):

88 Market Street
Brantford, Ontario
N3T 5N8

GENERAL SECURITY AGREEMENT

For valuable consideration. the undersigned (the "Borrower") agrees with Ontario Infrastructure Projects Corporation ("OIPC") as follows:

1. GRANT OF SECURITY INTEREST

As general and continuing security for the payment and performance when due of all Obligations, the Borrower hereby mortgages, charges and assigns to OIPC, and grants to OIPC, and OIPC takes, a Security Interest in the property described in the following paragraphs of this section, and in all property described in any schedules, documents or listings that the Borrower may from time to time sign and provide to OIPC in connection with this Agreement, and in all present and future Accessions to, and all Proceeds of, any such property (collectively, the "Collateral") as a general and continuing collateral security for the due payment of the obligations payable under the Financing Agreement (the "Financing Agreement") dated and effective as of December 3, 2007 and made between the Borrower and Ontario Infrastructure Projects Corporation:

(a) **Accounts Receivable**. All debts, book debts, accounts, claims, demands, money and choses in action, including without limitation, all claims against Her Majesty the Queen in right of Canada or any Province (other than Ontario) or Territory and all claims and benefits under any insurance policies;

(b) **Inventory**. All inventory, including, without limitation, all goods, merchandise, raw materials, goods in process, finished goods and other tangible personal property now or hereafter held for sale, lease or resale or that are to be furnished or have been furnished under a contract of service or that are used or consumed in the business of the Borrower;

(c) **Equipment**. All goods which are not inventory or consumer goods, including, without limitation, all fixtures, equipment, machinery, vehicles and other tangible personal property;

(d) **Chattel Paper, Instruments, Securities etc**. All chattel paper, instruments, warehouse receipts, bills of lading and other documents of title, whether negotiable or non-negotiable, shares, stock, warrants, bonds, debentures, debenture stock and other securities;

(e) **Intangibles**. All intangibles, including, without limitation, all contractual rights, goodwill, patents, trade-marks, copyrights, industrial designs and other industrial or intellectual property or rights therein;

(f) **Books and Accounts, etc**. All books, accounts, invoices, letters, papers, writings, certificates, receipts, documents and other records and data in any form or medium evidencing, representing, creating, giving rise to any rights in respect of or otherwise relating to the property described in paragraphs (a) to (e) inclusive; and

(g) **Proceeds**. All property in any form derived directly or indirectly from any dealing with any undertaking or property subject to the Security Interest or that indemnifies or compensates for such undertaking or property being destroyed, damaged, expropriated, stolen or lost and proceeds or proceeds whether of the same type or kind as the original proceeds.

2. GOVERNING LAW

This Agreement is governed by the laws of Ontario.

BRANTFORD POWER INC.

By: ______________________
Name: Andy Molenaar
Title: Director

I have authority to bind the Corporation.

By: ______________________
Name: Heather Wyatt c/s
Title: Board Secretary

I have authority to bind the Corporation.

By: ______________________
Name: c/s
Title:

ADDITIONAL TERMS AND CONDITIONS. THE ADDITIONAL TERMS AND CONDITIONS (INCLUDING ANY SCHEDULES) ON THE FOLLOWING PAGES FORM PART OF THIS AGREEMENT.

The Borrower has signed this Agreement with effect on December 3rd, 2007.

GENERAL SECURITY AGREEMENT
ADDITIONAL TERMS AND CONDITIONS

1. FINANCING AGREEMENT

Reference is hereby expressly made to the Financing Agreement and all instruments supplemental thereto for a statement and description of, among other things, the liability of the Borrower for payment of the Obligations, the terms, conditions, covenants and warranties upon which the Obligations are issued and held, and the rights and remedies of OIPC, all to the same effect as if the provisions of the Financing Agreement were herein set out.

2. PLACES OF BUSINESS

The Borrower represents and warrants that the locations of all existing Places of Business are specified in Schedule "BB". The Borrower will promptly notify OIPC in writing of any additional Places of Business as soon as they are established. Subject to Section 5, the Collateral will at all times be kept at the Places of Business and will not be removed without OIPC's prior written consent.

3. COLLATERAL FREE OF CHARGES

The Borrower represents and warrants that the Collateral is, and agrees that the Collateral will at all times be free, of any Charge or trust except in favour of OIPC or incurred with OIPC's prior written consent. OIPC may, but will not have to, pay any amount or take any action required to remove or redeem any unauthorized Charge. The Borrower will immediately reimburse OIPC for any amount so paid and will indemnify OIPC in respect of any action so taken.

4. USE OF COLLATERAL

The Borrower will not, without OIPC's prior written consent, sell, lease otherwise dispose of any of the Collateral (other than Inventory, which may be sold, leased or otherwise disposed of in the ordinary course of the Borrower's business). All Proceeds of the Collateral (including among other things received in respect of Receivables), whether or not arising in the ordinary course of the Borrower's business, will be received by the Borrower as trustee for OIPC and will be immediately paid to OIPC.

5. INSURANCE

The Borrower will keep the Collateral insured to its full insurable value against loss or damage by fire and such other risks as are customarily insured for property similar to the Collateral (and against such other risks as OIPC may reasonably require). At OIPC's request, all policies in respect of such insurance will contain a loss payable clause in favour of OIPC and in any event the Borrower assigns all proceeds of insurance on the Collateral to OIPC. The Borrower will, from time to time at OIPC's request, deliver such policies (or satisfactory evidence of such policies) to OIPC. If the Borrower does not obtain or maintain such insurance, OIPC may, but will not have to, do so. The Borrower will immediately reimburse OIPC for any amount so paid. The Borrower will promptly give OIPC written notice of any loss or damage to all or any part of the Collateral.

6. INFORMATION AND INSPECTION

The Borrower will from time to time immediately give OIPC in writing all information requested by OIPC relating to the Collateral, the Places of Business, and the Borrower's financial or business affairs. The Borrower will promptly advise OIPC of the Serial Number, model year, make and model of each Serial Number Good at any time included in the Collateral that is held as Equipment, including in circumstances where the Borrower ceases holding such Serial Number Good as Inventory and begins holding it as Equipment. OIPC may from time to time inspect any Books and Records and any Collateral, wherever located. For that purpose OIPC may, without charge, have access to each Place of Business and to all mechanical or electronic equipment, devices and processes where any of them may be stored or from which any of them may be retrieved. The Borrower authorizes any Person holding any Books and Records to make them available to OIPC, in a readable form upon request by OIPC.

7. RECEIVABLES

If the Collateral includes Receivables, OIPC may advise any Person who is liable to make any payment to the Borrower of the existence of this Agreement. OIPC may from time to time confirm with such Persons the existence and the amount of the Receivables. Upon an Event of Default, OIPC may collect and otherwise deal with the Receivables in such manner and upon such terms, as OIPC considers appropriate.

8. RECEIPTS PRIOR TO DEFAULT

Until an Event of Default, all amounts received by OIPC as Proceeds of the Collateral will be applied on account of the Liabilities in such manner and at such times as OIPC may consider appropriate or, at OIPC's option, may be held unappropriated in a collateral account or released to the Borrower.

9. DEFAULT

(1) **Events of Default**. "Event of Default" means any of the events described in paragraph 13(c) of the Financing Agreement. In case an Event of Default shall occur and be continuing, the full unpaid principal amount together with interest accrued thereon of any obligations outstanding payable under the Financing Agreement at the time of the occurrence, may become or be declared due before stated maturity by OIPC.

(2) **Additional Rights upon Default**. Upon the occurrence of any Event of Default, OIPC and a Receiver, as applicable, will to the extent permitted by law have the following additional rights:

> (a) Appointment of Receiver. OIPC may by instrument in writing appoint any Person as a Receiver of all or any part of the Collateral. OIPC may from time to time remove or replace a Receiver, or make application to any court of competent jurisdiction for the appointment of a Receiver. Any Receiver appointed by OIPC will (for purposes relating to responsibility for the Receiver's acts or omissions) be considered to be the Borrower's agent. OIPC may from time to time fix the Receiver's remuneration and the Borrower will pay OIPC the amount of such

remuneration. OIPC will not be liable to the Borrower or any other Person in connection with appointing or not appointing a Receiver or in connection with the Receiver's actions or omissions.

(b) Dealings with the Collateral. OIPC or a Receiver may take possession of all or any part of the Collateral and retain it for as long as OIPC or the Receiver considers appropriate, receive any rents and profits from the Collateral, carry on (or concur in carrying on) all or any part of the Borrower's business or refrain from doing so, borrow on the security of the Collateral, repair the Collateral, process the Collateral, prepare the Collateral for sale, lease or other disposition, and sell or lease (or concur in selling or leasing) or otherwise dispose of the Collateral on such terms and conditions (including among other things by arrangement providing for deferred payment) as OIPC or the Receiver considers appropriate. OIPC or the Receiver may (without charge and to the exclusion of all other Persons including the Borrower), enter upon any Place of Business.

(c) Realization. OIPC or a Receiver may use, collect, sell, lease or otherwise dispose of, realize upon, release to the Borrower or other Persons and otherwise deal with, the Collateral in such manner, upon such terms (including among other things by arrangement providing for deferred payment) and at such times as OIPC or the Receiver considers appropriate. OIPC or the Receiver may make any sale, lease or other disposition of the Collateral in the name of and on behalf of the Borrower or otherwise.

(d) Application of Proceeds After Default. All Proceeds of Collateral received by OIPC or a Receiver may be applied to discharge or satisfy any expenses (including among other things the Receiver's remuneration and other expenses of enforcing OIPC's rights under this Agreement), Charges, borrowings, taxes and other outgoings affecting the Collateral or which are considered advisable by OIPC or the Receiver to preserve, repair, process, maintain or enhance the Collateral or prepare it for sale, lease or other disposition, or to sell, lease or otherwise dispose of the Collateral. The balance of such Proceeds will be applied to the Obligations in such manner and at such times as OIPC considers appropriate and thereafter will be accounted for as required by law.

(e) Other Legal Rights. Before and After Default. OIPC will have in addition to the rights specifically provided in this Agreement, the rights of a secured party under the PPSA, as well as the rights recognized at law and in equity. No right will be exclusive of or dependent upon or merge in any other right, and one or more of such rights may be exercised independently or in combination from time to time.

(f) Deficiency. The Borrower will remain liable to OIPC for payment of any obligations under the Financing Agreement that are outstanding following realization of all or any part of the Collateral.

10. OIPC NOT LIABLE

OIPC will not be liable to the Borrower or any other Person for any failure or delay in exercising any of its rights under this Agreement (including among other things any failure to take possession of, collect, or sell, lease or otherwise dispose of any Collateral). None of OIPC, a Receiver or any agent of OIPC is required to take, or will have any liability for any failure to take or delay in taking, any steps necessary or advisable to preserve rights against other Persons under any Chattel Paper, Securities or Instrument in possession of OIPC, a Receiver or OIPC's agent.

11. CHARGES AND EXPENSES

The Borrower agrees to pay on demand all costs and expenses incurred (including among other things legal fees on a solicitor and client basis) and fees charged by OIPC in connection with obtaining or discharging this Agreement or establishing or confirming the priority of the Charges created by this Agreement or by law, compliance with any demand by any Person under the PPSA to amend or discharge any registration relating to this Agreement, and by OIPC or any Receiver in exercising any remedy under this Agreement (including among other things presuming, repairing, processing, preparing for disposition and disposing of the Collateral by sale, lease or otherwise) and in carrying on the Borrower's business. All such amounts will bear interest from time to time at the highest interest rate then applicable to any of the Liabilities, and the Borrower will reimburse OIPC upon demand for any amount so paid.

12. FURTHER ASSURANCES

The Borrower will from time to time immediately upon request by OIPC take such action (including among other things the signing and delivery of financing statements and financing change statements, other schedules, documents or listings describing property included in the Collateral, further assignments and other documents, and the registration of this Agreement) as OIPC may require in connection with the Collateral or as OIPC may consider necessary to give effect to this Agreement. If permitted by law, the Borrower waives the right to sign or receive a copy of any financing statement or financing change statement, or any statement issued by any registry that confirms any registration of a financing statement or financing change statement, relating to this Agreement. The Borrower irrevocably appoints the Senior Vice President, Business Development and Corporate Services of OIPC as the Borrower's attorney (with full powers of substitution and delegation) to sign, upon an Event of Default, all documents required to give effect to this section. Nothing in this section affects the right of OIPC as secured party, or any other Person on OIPC's behalf, to sign and file or deliver (as applicable) all such financing statements, financing change statements, notices, verification agreements and other documents relating to the Collateral and this Agreement as OIPC or such other Person considers appropriate.

13. DEALINGS BY OIPC

OIPC may from time to time increase, reduce, discontinue or otherwise vary the Borrower's credit facilities, grant extensions of time and other indulgences, take and give up any Charge, abstain from taking, perfecting or registering any Charge, accept compositions, grant releases and discharges and otherwise deal with the Borrower, Borrowers of the Borrower, guarantors and others, and with the Collateral and any Charges held by OIPC, as OIPC considers appropriate without affecting the Borrowers obligations to OIPC or OIPC's rights under this Agreement.

14. DEFINITIONS IN THIS AGREEMENT

"**Accessions**", "**Account**", "**Chattel Paper**", "**Document of Title**", "**Equipment**", "**Goods**", "**Instrument**", "**Intangible**", "**Inventory**", "**Proceeds**", "**Purchase-Money Security Interest**" and "**Security Interest**" have the respective meanings given to them in the PPSA.

"**Books and Records**" means all books, records, files, papers, disks, documents and other repositories of data recording, evidencing or relating to the Collateral to which the Borrower (or any Person on-the Borrower's behalf) has access.

"**Charge**" means any mortgage, charge, pledge, hypothecation, lien (statutory or otherwise), assignment, financial lease, title retention-agreement or arrangement, security interest or other encumbrance of any nature however arising, or any other security agreement or arrangement creating in favour of any creditor a right in respect of a particular property that is prior to the right of any other creditor in respect of such property.

"**Consumer Goods**" has the meaning given to it in the PPSA.

"**Event of Default**" has the meaning set out in subsection 11(1).

"**Obligations**" means all present and future indebtedness and liability of every kind, nature and description (whether direct or indirect, joint or several, absolute or contingent, matured or unmatured) of the Borrower to OIPC, wherever and however incurred and any unpaid balance thereof, including, without limitation, under or in respect of the Financing Agreement.

"**Money**" has the meaning given to it in the PPSA or, if there is no such definition, means a medium of exchange authorized or adopted by the Parliament of Canada as part of the currency of Canada, or by a foreign government as part or its currency

"**Person**" means any natural person or artificial body (including among others any firm, corporation or government).

"**Personal Property**" means personal property and includes among other things Inventory, Equipment, Receivables, Books and Records, Chattel Paper, Goods, Documents of Title, Instruments, Intangibles (including intellectual property), Money and Securities, and includes all Accessions to such property.

"**Place of Business**" means a location where the Borrower carries on business or where any of the Collateral is located (including any location described in Schedule "BB").

"**PPSA**" means the *Personal Property Security Act, 1990* (Ontario), as such legislation may be amended, renamed or replaced from time to time (and includes all regulations from time to time made under such legislation).

"**Receivables**" means all debts, claims and choses in action (including among other things Accounts and Chattel Paper) - now or in the future due or owing to or owned by the Borrower.

"**Receiver**" means a receiver or a receiver and manager.

"**Securities**" has the meaning given to it in the PPSA or, if there is no such definition and the PPSA defines "security" instead, it means the plural of that term.

"**Serial Number**" means the number that the Person who manufactured or constructed a Serial Number Good permanently marked or attached to it for identification purposes or, if applicable. such other number as the PPSA stipulates as the serial number or vehicle information number to be used for registration purposes of such Serial Number Good.

"**Serial Number Good**" means a motor vehicle, trailer, mobile home, aircraft airframe, aircraft engine or aircraft propeller, boat or an outboard motor for a boat.

15. GENERAL

(a) Reservation of the Last Day of any Lease. The Charges created by this Agreement do not extend to the last day of the term of any lease or agreement for lease; however, the Borrower will hold such last day in trust for OIPC and, upon the exercise by OIPC of any of its rights under this Agreement following Default, will assign such last day as directed by OIPC.

(b) Attachment of Security Interest. The Security Interests created by this Agreement are intended to attach (i) to existing Collateral when the Borrower signs this Agreement, and (ii) to Collateral subsequently acquired by the Borrower, immediately upon the Borrower acquiring any rights in such Collateral. The parties do not intend to postpone the attachment of any Security Interest created by this Agreement.

(c) Purchase-Money Security Interest. If OIPC gives value for the purpose of enabling the Borrower to acquire rights in or to any of the Collateral, the Borrower will in fact apply such value to acquire those rights (and will provide OIPC with such evidence in this regard as OIPC may require), and the Borrower grants to OIPC, and OIPC takes, a Purchase-Money Security Interest in such Collateral to the extent that the value is applied to acquire such rights. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the amount of any such value.

(d) Entire Agreement. OIPC has not made any representation or undertaken any obligation in connection with the subject matter of this Agreement other than as specifically set out in this Agreement, and in particular nothing contained in this Agreement will require OIPC to make, renew or extend the time for payment of any loan or other credit accommodation to the Borrower or any other Person.

(a) Additional Security. The Charges created by this Agreement are in addition and without prejudice to any other Charge now or later held by OIPC. No Charge held by OIPC will be exclusive of or dependent upon or merge in any other Charge, and OIPC may exercise its rights under such Charges independently or in combination.

(b) Severability: Headings. Any provision of this Agreement that is void or unenforceable in any jurisdiction is, as to that jurisdiction, ineffective to that extent without invalidating the remaining provisions of this Agreement. The headings in this Agreement are for convenience only and do not limit or extend the provisions of this Agreement.

(c) Interpretation. When the context so requires, the singular will be read as the plural, and vice versa.

(d) Copy of Agreement. The Borrower acknowledges receipt of a copy of this Agreement.

(e) Notice. OIPC may send to the Borrower, by prepaid regular mail addressed to the Borrower at the Borrower's address last known to OIPC, copies of any document required by the PPSA to be delivered by OIPC to the Borrower. Any document mailed in this manner will be deemed to have been received by the Borrower upon the earlier of actual receipt by the Borrower and the expiry of 10 days after the mailing date. A certificate or affidavit of any of OIPC's authorized representatives is admissible in evidence to establish the mailing date.

(f) Enurement; Assignment. This Agreement will enure to the benefit of and be binding upon (i) OIPC, its successors and assigns, and (ii) the Borrower and the Borrower's heirs, executors, administrators, successors and permitted assigns. The Borrower will not assign this Agreement without OIPC's prior written consent.

SCHEDULE "AA"

The following is a description of property included in the Collateral (describe personal property by item or kind: if space is insufficient (use a separate sheet) :

SCHEDULE "BB"

The following are the Places of Business (if space is insufficient, use a separate sheet):

88 Market Street
Brantford, Ontario
N3T 5N8

gowlings montréal · ottawa · toronto · hamilton · waterloo region · calgary · vancouver · moscow · london

November 27, 2012

DELIVERED

Ms. Bernadette Chung
Ontario Infrastructure and Lands Corporation
777 Bay Street
Suite 900
Toronto, Ontario
M5G 2C8

Dear Bernadette:

Re: Brantford Power Inc. – Financing Agreement No. 11Bra9041011070FA

I am enclosing on behalf of Brantford Power Inc. a copy of the above-noted Financing Agreement duly signed by Brantford Power Inc and which incorporates a signed copy of the General Security Agreement in favour of Ontario Infrastructure and Lands Corporation.

In order for Brantford Power to have its fully executed copy, I would appreciate it if you could arrange to have a second version signed by OILC and sent directly to Brian Ambrose at Brantford Power.

Yours very truly,

Paul H. Harricks

PHH/kmm
Encl.

Ontario
Infrastructure Ontario

777 Bay Street, Suite 900, Toronto, ON M5G 2C8
777, rue Bay, bureau 900, Toronto, ON M5G 2C8

November 6, 2012

Brantford Power Inc.
84 Market Street, 3rd Floor
Brantford, ON, N3T 5N8

Dear Sir,

We are pleased to offer Brantford Power Inc. the following credit facilities (the "**Credit Facilities**"), subject to the terms and conditions set forth below and in the attached Schedules (collectively, the "**Agreement**" or "**Financing Agreement No. 11Bra9041011070FA**"). Unless otherwise provided, all dollar amounts are in Canadian currency. This Agreement is effective as of November 6, 2012 ("**Effective Date**") and supersedes and replaces the term sheet dated February 2, 2012 between OILC and the Borrower describing the terms and conditions of the credit facilities referred to herein.

Borrower:	Brantford Power Inc. (the "**Borrower**")
Lender:	Ontario Infrastructure and Lands Corporation ("**OILC**")
Aggregate Credit Limit:	$4,000,000 (the "**Committed Amount**")
Type of Credit Facilities:	1. Non-revolving floating rate construction loan in the aggregate maximum principal amount of $4,000,000 (the "**Construction Facility**") available until the Construction Loan Maturity Date. 2. Non-revolving fixed rate amortizing term loan in the aggregate maximum principal amount of $4,000,000 (the "**Term Facility**") available until the Term Loan Maturity Date.
Purpose:	To support the 2011 General Capital Spending Program (the "**Project**").
Construction Loan Maturity Date:	December 31, 2012, subject to acceleration by OILC pursuant to the terms set out in the Agreement.
Term Facility Maturity Date:	30 years after the conversion of the Construction Facility to the Term Facility, subject to acceleration by OILC pursuant to the terms set out in the Agreement.
Interest Rates:	1. Construction Facility: Floating rate posted on OILC's website as at the first Business Day of each calendar month. The indicative annual interest rate for the Construction Loan as at **March 14, 2012** is 1.75%.

	2. Term Facility: Fixed rate as at the date of the Term Loan based on OILC's cost of funds plus OILC's prevailing spread assigned to the borrower sector for program delivery costs and risks. The indicative annual interest rate for the **Amortizing** Term Loan as at **March 14, 2012** is **4.04%**. For all Credit Facilities, interest payments will be made in accordance with Schedule "A" attached hereto.
Repayment Amounts:	Construction Facility: Interest only. The interest on a floating basis is paid monthly with no principal repayment required. Term Facility: 60 equal semi-annual installments of blended principal and interest for the term of this loan at a fixed interest rate.
Standby Fee:	0.25% per annum of the unadvanced balance of the Committed Amount, subject to the terms set out in the Agreement.
Drawdown:	1. Construction Facility: Construction Loan Advances shall be made on either the 1st or 15th day of the month. The Borrower shall deliver a drawdown notice no later than 20 days prior to the requested Advance date. 2. Term Facility: Conversions of Construction Loan Advances shall be made either on the 1st or 15th day of the month. The Borrower shall deliver a conversion notice requesting a conversion of a Construction Loan Advance to a Term Loan Advance no later than 60 days prior to the Conversion Date.
Disbursement Conditions:	In addition to the customary conditions precedent for a drawdown set forth in Schedule "A", each of the following conditions precedent shall have been satisfied before each drawdown under the Construction Facility and the Term Facility, as applicable: **Construction Facility**: N/A **Term Facility:** N/A
Evidence of Indebtedness:	OILC shall record the principal amount of the Advances, the payment of principal and interest on account of the Advances, and all other amounts becoming due to OILC under this Agreement. OILC's accounts and records shall constitute, in absence of manifest error, *prima facie* evidence of the indebtedness of the Borrower under the Credit Facilities. For each Term Loan Advance, the Borrower shall provide a promissory note in favour of OILC which shall include the scheduled dates for principal repayment and interest payments.
Repayment:	1. The Construction Facility is a non-revolving facility and no

	amounts repaid under the Construction Facility may be re-borrowed under the Construction Facility and it is understood by the parties that in no event shall any amount outstanding under the Construction Facility be repaid in full later than the Construction Loan Maturity Date, except for Conversions permitted in accordance with this Agreement. Any conversion of a Construction Loan to a Term Loan must occur on or prior to the Construction Loan Maturity Date. 2. The Term Facility is a non-revolving facility and no amounts repaid under the Term Facility may be re-borrowed under the Term Facility and it is understood by the parties that in no event shall the amounts outstanding under the Term Facility be repaid in full later than the Term Facility Maturity Date.
Security:	The following security shall be provided to support all present and future indebtedness and liability of the Borrower, and shall be registered in first position unless otherwise noted below, and shall be on OILC's standard form, supported by resolutions and legal opinion, all acceptable to OILC: a) a 2nd priority ranking general security agreement (the "**GSA**") subject only to the 1st priority ranking GSA registered by the Royal Bank of Canada (the "**RBC**") attached hereto as Schedule "E". b) a subordination and postponement agreement in which the City of Brantford subordinates and postpones its security interest for the promissory note of $24,189,168 in favour of OILC attached hereto as Schedule "F"; c) a valid certificate of insurance in respect of fire and other perils on the property and assets of the Borrower with OILC added as a loss payee; and d) all other security documentation as may be reasonably required from time to time to protect the interests of OILC. All of the above security shall be referred to collectively in this Agreement as the "**OILC Security**".
Representations and Warranties:	The Borrower shall and is deemed to make the Representations and Warranties as set out in Schedule "A".
Positive Covenants:	So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower shall and shall ensure that its subsidiaries and each of the Guarantors observe the Positive Covenants as set out in Schedule "A" " and in addition, the Borrower shall:

	a) notify OILC forthwith of any assignment or transfer of any personal property security registrations under the *Personal Property Security Act* ("*PPSA*") by the Royal Bank of Canada ("RBC"), including that bearing registration number 20010502 1444 1530 6849.
Reporting:	The Borrower shall furnish OILC as soon as practicable with: a) a copy of audited annual financial statements within one hundred and twenty (120) days after the end of each Fiscal Year of the Borrower; b) a copy of semi-annual financial statements(internally prepared) within sixty (60) days after the end of each 2nd Fiscal Quarter of the Borrower; c) a copy of annual operating and capital budgets of the Borrower within sixty (60) days after the end of the Fiscal Year of the Borrower; d) a notification within five (5) Business Days if the Borrower changes its operating Bank, which currently is the Royal Bank of Canada. The Borrower shall forward OILC a copy of the term sheet issued by the Borrower's new operating Bank with regard to the new credit facilities once it becomes available; e) any other reports upon request relevant to the Borrower's business and financial fundamentals including without limitation, proof of tax payments and statutory deductions, notification of applications or filings submitted to the OEB, IESO or any other regulatory body; and f) with any other financial reporting information that OILC may require at its discretion and at any time prepared in accordance with GAAP.
Negative Covenants:	So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower shall and shall ensure that its subsidiaries and each of the Guarantors shall observe the Negative Covenants set out in Schedule "A" and in addition the Borrower shall not and shall ensure its subsidiaries not to: a) make loans to, invest in, or make guarantee for any affiliated or unaffiliated companies and/or persons in an aggregate amount exceeding 2.5% of its total assets; b) sell assets outside the ordinary course of business in an aggregate amount that exceeds 2.5% of its total assets unless prior to such sale, the Borrower or its subsidiaries has or have acquired replacement assets for a value not less than the assets being sold; c) distribute to the shareholder (except if the shareholder is the

	Borrower), in the form of bonus interest, dividend or share redemption, any amount that will exceed the Permitted Annual Distribution Limit; d) increase the limit of credit facility #1, being a revolving line of credit for the amount of $7,000,000 with the Royal Bank of Canada ("RBC"), without first obtaining written permission by OILC; e) increase the limit of credit facility #2, being a letter of guarantee for the amount of $13,375,721, unless the increase is required by the Independent Electricity System Operator (the "IESO") and the increase is pursuant to the Borrower's normal course of business; f) increase the limits of credit facility #3, being a non-revolving term facility up to $4,724,000 or credit facility #4, being a non-revolving term facility up to $828,000.
Permitted Liens:	Permitted Liens are listed in Schedule "A and also include: a) any Liens in connection with existing credit facilities provided by the Royal Bank of Canada to the Borrower not to exceed the respective credit limits as stipulated in the Negative Covenants section of this Agreement.
Financial Covenants:	a) The Borrower shall maintain a Debt Service Coverage Ratio at 1.2 to 1 or higher for the term of this Agreement; such ratio will otherwise be tested and calculated as of the end of each Fiscal Year as applicable. b) The Borrower shall maintain a Debt to Capitalization Ratio at 60% or lower for the term of this Agreement; such ratio will be tested and calculated as of the end of each Fiscal Year as applicable. c) The Borrower shall maintain a Current Ratio at 1.1 to 1 or higher for the term of this Agreement; such ratio will be tested and calculated as of the end of each Fiscal Year as applicable. d) OILC agrees to revise the required financial ratios should the difference between the rules under GAAP as at December 31, 2010 and the rules under International Financial Reporting Standards ("**IFRS**") have a material adverse impact on its financial ratios. The revision shall be based on the original intent of the required ratios in this Agreement but allow for reconciliation of the current accounting rules and the IFRS.

Events of Default:	OILC may accelerate the payment of principal and interest under any committed credit facility hereunder and/or terminate any undrawn portion of any committed credit facility hereunder, at any time after the occurrence of any one of the Events of Default contained in Schedule "A" attached hereto and after any one of the following additional Events of Default as further described in Schedule "A": 1. any material adverse change in legislation or regulation. 2. any material judgments. 3. The Borrower fails to hold a valid license from the OEB to distribute electricity. 4. The Borrower fails to deliver a fully executed subordination and postponement agreement signed by the City of Brantford in a form satisfactory to OILC no later than May 1, 2013.
Project Management Requirements:	The Borrower shall: (1) have a qualified project manager in place for the Project subject to OILC's prior approval; (2) comply with OILC's project management reporting requirements for the Project; and (3) submit the Reports to OILC pursuant to and as further described in the attached Schedule "C" to this Agreement. OILC reserves the right to impose additional Project approval requirements should, in the opinion of the Project Monitor, any issue arise with respect to the continued ability of the Borrower to complete the Project within the current approved budget.
Schedule "A" – Additional Terms and Conditions:	Schedule "A" sets out the Additional Terms and Conditions ("**Additional Terms and Conditions**") which apply to the Credit Facilities. The Additional Terms and Conditions, including the defined terms set out therein, form part of this Agreement, unless and to the extent this letter states specifically that one or more of the Additional Terms and Conditions do not apply or are modified.

We trust you will find these credit facilities helpful in meeting your ongoing financial requirements. We ask that if you wish to accept this offer of financing (which includes the Additional Terms and Conditions), please do so by signing and returning the attached duplicate copy of this letter to the undersigned. This offer will expire if not accepted in writing and received by OILC on or before November ~~16~~, 2012.

20 Dec. D

Yours Truly,

ONTARIO INFRASTRUCTURE AND LANDS CORPORATION

by: Dale Lawr

Name: Dale Lawr
Title: Chief Administrative Officer

TO: ONTARIO INFRASTRUCTURE AND LANDS CORPORATION

Brantford Power Inc. hereby accepts the foregoing offer and Financing Agreement No. 11Bra9041011070FA this 20 day of November, 2012.

BRANTFORD POWER INC.

by: ___________________________

Name: BRIAN D'AMBOISE

Title: CFO

____

Name: Heather Wyatt

Title: Board Secretary

We have authority to bind the Corporation.

SCHEDULE "A"

ADDITIONAL TERMS AND CONDITIONS

1. INTEREST CALCULATION AND PAYMENT

(a) Construction Facility

(i) Each Construction Loan Advance shall bear interest at a floating rate per annum as determined by OILC based on OILC's cost of funds plus OILC's prevailing spread assigned to the borrower sector for program delivery costs and risks (the "**Advance Interest Rate**"). The Advance Interest Rate for a Construction Loan Advance for the initial Interest Period shall be set by OILC based on OILC's cost of funds plus OILC's prevailing spread assigned to the borrower sector for program delivery costs and risks and will be effective on the date of the Construction Loan Advance. The Advance Interest Rate for each subsequent Interest Period shall be reset on the first Business Day of each calendar month (each such Business Day, a "**Reset Date**") for the following Interest Period as determined by OILC based on OILC's cost of funds plus OILC's prevailing spread assigned to the borrower sector for program delivery costs and risks and will be effective on the Reset Date, which Advance Interest Rate as so reset shall apply to the Construction Loan Advance for such Interest Period until reset again.

(ii) Interest accrued during an Interest Period on the principal balance of a Construction Loan Advance outstanding during such Interest Period shall be payable in arrears on the first Business Day of the calendar month following the Interest Period in an amount equal to the product of the Advance Interest Rate in effect during such Interest Period and the principal balance of the Construction Loan Advance outstanding as at the Reset Date for such Interest Period, or in the case of an initial Interest Period the principal balance outstanding on the date of the Construction Loan Advance, multiplied by a fraction, the numerator of which is the number of days in the Interest Period and the denominator of which is 365.

(iii) For purposes of disclosure pursuant to the *Interest Act (Canada),* the yearly rate of interest which is equivalent to a rate of interest payable in respect of the principal amount of any Advance for any period of less than a year may be determined by multiplying the rate of interest for such period by a fraction, the numerator of which is the actual number of days in a year commencing on and including the first day in such period and ending on but excluding the corresponding day in the next calendar year and the denominator of which is the actual number of days in such period.

(iv) Payments of interest due on each Advance under the Construction Facility shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OILC by the execution and delivery of the attached Schedule B to this

Agreement, together with such other authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OILC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

(v) The Borrower shall pay interest to OILC on any overdue amount of principal or interest in respect of any Advance, both before and after demand, default, maturity and judgment, at a rate per annum equal to the Prime Rate plus 200 basis points, calculated on a daily basis from the date such amount becomes overdue for so long as such amount remains overdue, and the Borrower shall pay to OILC any and all costs and losses incurred by OILC as a result of the payment having been overdue.

(vi) The principal amount outstanding under the Construction Facility, together with all interest, fees and other amounts payable under this Agreement in connection with the Construction Facility, shall be due and payable to OILC on the earlier to occur of:

(A) demand by OILC following the occurrence of an Event of Default which is continuing; and

(B) the Construction Loan Maturity Date subject to OILC's right to extend the Construction Loan Maturity Date in its sole discretion.

(b) <u>Conversion to Term Loan and Advances under Term Facility</u>

(i) Subject to the satisfaction of the conditions precedent hereinafter set forth in paragraph 4(b) and in compliance with the terms of this Agreement, all or any portion of the Construction Loan may, at the option of the Borrower, be converted to the Term Loan at any time during the Construction Period upon at least sixty (60) days prior written notice by the Borrower to OILC. In the event that the Construction Loan has not been converted to the Term Loan in accordance with the foregoing provisions during the Construction Period, the Construction Loan may, at the sole option of OILC and in its absolute discretion, be converted to the Term Loan on the Construction Loan Maturity Date. Any conversion to the Term Loan as aforesaid shall be deemed as an advance under the Term Facility and shall not affect the Borrower's obligations hereunder in respect of interest, fees or other amounts owing hereunder prior to conversion other than the principal.

(ii) The interest rate for each advance made or deemed to be made under the Term Facility shall be fixed by OILC at the time of such advance based on OILC's cost of funds plus OILC's prevailing spread assigned to the borrower sector for program delivery costs and risks. A rate confirmation letter will be sent to the Borrower by OILC confirming the interest rate for such advance under the Term Facility.

(iii) Payments of principal and interest due on each advance under the Term Facility, and any other payments due under this Agreement, shall be made by pre-authorized debit from an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OILC by the execution and delivery of the attached Schedule B to this Agreement, together with such authorizations, voided cheques and other documentation as the deposit-taking institution and the rules of the Canadian Payments Association may require for such pre-authorized debit, and the Borrower undertakes to notify OILC immediately in writing of any changes in its designated account for the purposes of pre-authorized debits.

(c) Repayment of the Term Loan

The principal amount of the Term Loan, together with all interest, fees and other amounts payable under this Agreement in connection with the Term Loan, shall be due and payable to OILC on the earlier to occur of:

(A) demand by OILC following the occurrence of an Event of Default which is continuing; and

(B) the Facilities Maturity Date.

2. DRAWDOWN PROVISIONS

(a) The Borrower may request a Construction Loan Advance or a Term Loan Advance to be made on either the 1st or the 15th day of any calendar month or the first Business Day following such date if such date is not a Business Day (either of which is defined as the "**Advance Date**"). For each Construction Loan, the Borrower shall deliver a Drawdown Notice no later than 20 days prior to the requested Advance Date. The Borrower shall deliver a Conversion Notice for a conversion of Construction Loan Advances to a Term Loan Advance no later than 60 days prior to the requested Conversion Date.

(b) The principal amount of all Advances will be tendered to the Borrower by electronic transfer of funds to an account of the Borrower maintained with a deposit-taking institution, such account to be designated by notice in writing to OILC by the execution and delivery of the attached Schedule B to this Agreement and the Borrower undertakes to notify OILC immediately in writing of any changes in its designated account for the purposes of such deposit.

3. RIGHT OF DEDUCTION, SECURITY AND STANDBY FEES

(a) If the Borrower fails to meet its obligations to OILC under the Agreement, and as security for the satisfaction by the Borrower of the Obligations, the Borrower hereby agrees, pursuant to subsections 25(1), 25(2) and 25(3) of the *Ontario Infrastructure and Lands Corporation Act, 2011* (Ontario), as amended from time to time hereafter, that the Minister of Finance is entitled to deduct from money appropriated by the Legislative Assembly of Ontario for payment to the Borrower, or from money appropriated by such Assembly for payment to the Borrower in respect of such matters as may be specified, amounts not exceeding the amounts that the Borrower fails to pay to OILC pursuant to this Agreement and to pay such amounts to OILC from the Consolidated Revenue Fund.

(b) As continuing collateral security for the payment by the Borrower to OILC under the terms of this Agreement and for performance by the Borrower of its obligations hereunder, the Borrower acknowledges and agrees that OILC shall have the benefit of the OILC Security.

(c) The Borrower shall pay OILC a standby fee (the "**Standby Fee**") calculated at the rate of 25 basis points (0.25% per annum) on the unadvanced balance of the Committed Amount should the Borrower fail to draw any funds pursuant to this Agreement from OILC during any period of twelve (12) months commencing initially from the Effective Date of this Agreement and subsequently from the date of the draw of any such funds until the earlier of the Facilities Maturity Date or the full advance of the Committed Amount. The Standby Fee shall be calculated daily on the basis of a calendar year of 365 or 366 days, as the case may be, and shall be due and payable by the Borrower monthly in arrears on the last Business Day of each month in accordance with the pre-authorized debt procedure outlined in paragraphs 1(a)(iv) and 1(b)(iii) above.

4. DISBURSEMENT CONDITIONS

(a) Construction Loan. Unless waived by OILC or previously delivered or satisfied to OILC's sole discretion, the following are the conditions precedent to the obligation of OILC to make any advance under the Construction Facility:

(i) Prior Liens: The Borrower shall have paid in full and discharged all principal balances and all other sums due and owing pursuant to any liens (including any liens arising under the CLA), charges, assessments, levies or other encumbrances of any nature affecting the Premises except for Permitted Liens;

(ii) Audit: At OILC's discretion, if any issues were raised in any audit conducted under paragraph 19(a). such issues have been resolved to OILC's satisfaction and/or OILC has neither required an audit under paragraph 19(a) nor is such an audit ongoing;

(iii) Taxes: The Borrower shall have provided to OILC, in a form satisfactory to OILC, evidence that all municipal property taxes, local improvement rates and other taxes which may give rise to lien against the Premises have been paid in full;

(iv) Insurance: The Borrower shall have provided to OILC and/or its insurance consultants with evidence satisfactory to OILC that all insurance required to be placed pursuant to the terms of this Agreement is in place;

(v) Security: The Borrower shall have executed and delivered or caused to be executed and delivered in favour of OILC the OILC Security, all in form and substance satisfactory to OILC, in its sole discretion. Notwithstanding the foregoing, the subordination and postponement agreement signed by the City of

Brantford is not required to be delivered prior to the first advance under the Construction Facility, but must be delivered no later than May 1, 2013;

(vi) Status: OILC shall be satisfied in its sole discretion that no event or circumstances has occurred or is likely to occur which may in any material respect, affect the basis upon which the Committed Amount was approved or which results or would result in a material adverse change in the Borrower's financial condition or ownership of the Premises;

(vii) Committed Amount Ceiling: The amount of the requested Advance when added to the aggregate amount of Advances then outstanding in respect of the Project does not exceed the Committed Amount;

(viii) Officers' Certificate: The Borrower shall provide to OILC an Officer's Certificate dated as of the date of each Advance, certifying:

(A) that all representations and warranties set forth in this Agreement and the OILC Security are true and correct on the date of the Advance;

(B) that all covenants and conditions in this Agreement to be observed or performed by the Borrower have been complied with, that no Event of Default exists and is continuing and as to such other matters as OILC may require; and

(C) that all conditions precedent to the Advance have been fulfilled or complied with; and

(ix) Opinion of Borrower's Counsel: The Borrower shall deliver to OILC an opinion of Borrower's counsel dated as of the date of the first Advance under the Construction Facility and addressed to OILC, in form and substance acceptable to OILC.

(b) Term Loan. Unless waived by OILC or previously delivered or satisfied to OILC's sole discretion, the following are the conditions precedent to the obligation of OILC to make any advance under the Term Loan that:

(i) Prior Liens: The Borrower shall have paid in full and discharged all principal balances and all other sums due and owing pursuant to any liens (including any liens arising under the CLA), charges, assessments, levies or other encumbrances of any nature affecting the Premises except for Permitted Liens;

(ii) Taxes: The Borrower shall have provided to OILC, in a form satisfactory to OILC, evidence that all municipal property taxes, local improvement rates and other taxes which may give rise to lien against the Premises have been paid in full;

(iii) Audit: At OILC's discretion, if any issues were raised in any audit conducted under paragraph 19(a), such issues have been resolved to OILC's satisfaction and/or OILC has neither required an audit under paragraph 19(a) nor is such an audit ongoing; and

(iv) Officers' Certificate: The Borrower shall provide to OILC an Officer's Certificate dated as of the date of each advance under the Term Loan, certifying:

(A) that all representations and warranties set forth in this Agreement and the OILC Security are true and correct on the date of the Term Loan Advance;

(B) that all covenants and conditions in this Agreement to be observed or performed by the Borrower have been complied with, that no default or event of default exists and as to such other matters as OILC may require; and

(C) that all conditions precedent to the advance under the Term Loan have been fulfilled or complied with.

5. REPRESENTATIONS AND WARRANTIES

The Borrower represents and warrants to OILC that:

(a) the information contained in the Application, to the extent that it relates to the Borrower or the Project, is true and correct in all material respects as of the date of this Agreement;

(b) the Borrower has been duly incorporated pursuant to the Act and the Borrower has the corporate power and capacity to:

(i) own, lease and operate its properties and assets and to carry on its activities as presently carried on;

(ii) to borrow money;

(iii) to enter into and complete the Project; and

(iv) to execute and deliver this Agreement and to perform its obligations hereunder;

(c) the Borrower has taken all necessary corporate action to authorize the execution, delivery and performance of this Agreement;

(d) this Agreement has been duly authorized, executed and delivered by the Borrower and constitutes a valid and legally binding obligation, enforceable against the Borrower in accordance with its respective terms, subject to applicable bankruptcy, insolvency and other laws affecting the enforcement of creditors' rights generally;

(e) the execution and delivery by the Borrower of this Agreement and the performance by the Borrower of its obligations hereunder do not violate, result in a breach of, or constitute a default under:

(i) any of the terms, conditions or provisions of its constating documents or by laws of the Borrower;

(ii) any resolution of the board of directors or any financial plan, budget, borrowing strategy or investment strategy of the Borrower; or

(iii) any statute, regulation or other law applicable to the Borrower;

(f) the Borrower is not currently in default under: (i) any Indebtedness; (ii) any loan documentation related to the Project; or (iii) any material agreements related to the Project; and the Borrower undertakes to immediately inform OILC if it is in default under any of these instruments or agreements at any time;

(g) all Project agreements and ancillary loan documentation have been executed and are in full force and effect;

(h) subject only to minor title defects not individually or in the aggregate material nor materially and adversely affecting the use thereof and subject to any security granted to OILC pursuant to the provisions hereof, the Borrower has good and marketable title to its real and personal properties free and clear of any encumbrances or security interests except Permitted Liens;

(i) since the date of incorporation of the Borrower, there has been no development materially adversely affecting the business or financial condition or position of the Borrower or its ability to carry on business as presently conducted or as contemplated hereunder to be conducted; and

(j) there is no litigation or judicial or administrative proceeding of any kind now existing, pending or to the Borrower's knowledge threatened that in any way seeks to restrain, enjoin, delay or otherwise adversely affect the commencement or completion of the Project or that would substantially impair the Borrower's ability to meet its debt obligations as they generally come due or that in any manner questions the proceedings and authority under which the Project or the borrowings applied for in the Application have been or will be authorized.

6. <u>ADDITIONAL POSITIVE COVENANTS</u>

The Borrower covenants and agrees with OILC that:

(a) the proceeds of the Advances provided by OILC shall be applied only for the purposes of capital expenditures in respect of hard and soft capital costs actually incurred or to be incurred by the Borrower for the Project and not for any other purpose;

(b) the Borrower shall duly and punctually pay or cause to be paid when due and payable the principal of and interest on all Advances and all other amounts owing in respect of all Advances, in conformity with the terms of this Agreement, and it shall faithfully observe and perform all the conditions, covenants and requirements of this Agreement;

(c) the Borrower shall at all times maintain its existence as a body corporate with all necessary approvals to carry on its operations as a corporation under Applicable Law and conduct its operations in a proper manner, and will keep or cause to be kept proper books of account and will take all necessary steps to ensure that its Material Related Entities conduct their operations in a proper manner and keep or cause to be kept proper books of account;

(d) the Borrower shall maintain insurance on its properties and assets and for the operation of its business whereby each such insurance policy shall (i) be written by insurers approved by OILC, acting reasonably, and (ii) provide for thirty (30) days written notice to OILC of a proposed cancellation or non-renewal from the insurer of any such policy or deletion or material change of any coverages thereunder or of any property covered thereby. OILC shall be entitled to retain an Insurance Consultant to review the existing insurance coverage to ascertain whether such insurance is adequate under the circumstances and the Borrower shall pay all amounts incurred by OILC for such review. The Borrower agrees to make such changes to its insurance policies as such Insurance Consultant may reasonably require and to the extent changes can reasonably be effected in accordance with market standards; the Borrower shall pay all amounts incurred by OILC to review the adequacy of the construction and operating insurance, and obtain all adequate insurance policies during the construction and operating phases of the Project; and

(e) the Borrower shall at all times comply with Applicable Law in the construction of the Project.

7. <u>NEGATIVE COVENANTS</u>

So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower shall not and shall ensure that its subsidiaries will not:

(a) create, incur, assume, or suffer to exist, any Lien of any nature, upon or with respect to any of its assets or undertakings, now owned or hereafter acquired, except for Permitted Liens;

(b) create, incur, assume or suffer to exist any other indebtedness for borrowed money (except for indebtedness resulting from Permitted Liens, if any) or guarantee or act as surety or agree to indemnify the debts of any other Person;

(c) merge or consolidate with any other Person, or acquire all or substantially all of the shares, assets or business of any other Person except as permitted under paragraph 10 below;

(d) terminate or enter into a surrender of any lease of any property mortgaged under the OILC Security;

(e) cease to carry on the business currently being carried on by each of the Borrower and its subsidiaries at the date hereof; and

(f) permit any change of ownership or change in the capital structure of the Borrower.

8. <u>ENVIRONMENTAL</u>

(a) The Borrower shall at all times comply with all applicable environmental laws and occupational health and safety laws, regulations and orders which affect the Borrower or any of its assets.

(b) The Borrower shall inform OILC in writing of each:

(i) environmental problem or condition which materially adversely affects the Borrower or any of its assets upon becoming aware of such problem; and

(ii) legal action or proceeding commenced against the Borrower with respect to any environmental matter which may materially adversely affect the Borrower or any of its assets, promptly upon the Borrower becoming aware of the commencement of such action or other proceeding.

(c) The Borrower shall specifically establish and maintain procedures for monitoring its continued compliance with applicable environmental laws, which procedures shall include periodic reviews of such compliance.

(d) If the Borrower (i) receives written notice that any material violation of any environmental law may have been committed or is about to be committed by it, (ii) receives written notice that any administrative or judicial complaint or order has been filed or is about to be filed against it alleging material violations of any environmental laws or requiring it to take any action of a material nature in connection with the release of Hazardous Materials into the environment, or (iii) receives any written notice from a governmental authority or other Person alleging that it may be liable or responsible for costs in a material amount associated with a response to or clean-up of a release of a Hazardous Material into the environment or any damages caused thereby, the Borrower shall provide to OILC with a copy of such notice within 10 Business Days of the Borrower's receipt thereof. The Borrower shall also provide to OILC, as soon as practicable after it becomes available, a copy of an environmental site assessment or audit report, if any, required to be submitted to any governmental authority. If any such assessment or report estimates the cost of any clean-up or remedial action required by such governmental authority, the Borrower shall provide evidence satisfactory to OILC of disbursements made from time to time to effect such clean-up or remedial action within such time as may be prescribed by such governmental authority.

(e) The Borrower shall indemnify OILC and its officers, directors, employees, agents, representatives, assignees, and the officers, directors, employees of each of them (each, an "**Indemnified Person**") and shall hold each of them harmless from and against any and all losses, liabilities, damage, costs, expenses and claims (including legal fees on a solicitor and client basis) relating to this Agreement or any other document delivered in connection with this Agreement and/or arising in respect of (i) any violation of an environmental law by the Borrower including the assertion of any Lien, (ii) the presence of any Hazardous Material affecting any real or personal property owned by it resulting in any way from the Borrower's use of such property, or (iii) the release by the Borrower of any Hazardous Material into the environment; provided that the Borrower shall not be obliged to indemnify any Indemnified Person for any losses, liabilities, damages, costs, expenses and claims which have arisen as a result of gross negligence or wilful misconduct of such Indemnified Person. The Borrower's obligations and indemnification under this section shall survive the payment and satisfaction of all obligations hereunder and the termination of this Agreement. OILC shall hold the benefit of this indemnity in trust for those other Indemnified Persons who are not parties to this Agreement.

9. TERM, TERMINATION AND DEFAULT

(a) This Agreement shall terminate ten (10) Business Days following the date on which the last Obligations outstanding hereunder are paid in full unless earlier terminated in accordance with paragraphs (b) or (c) below.

(b) OILC may terminate its obligations under this Agreement on thirty (30) days prior notice in writing to the Borrower if in the reasonable opinion of OILC the Borrower is in material default under this Agreement, other than for any cause enumerated in (c) below.

(c) OILC may terminate any or all of its obligations under this Agreement immediately, subject to paragraph 9(d) below,

(i) if the Borrower fails to make one or more payments of principal or interest in respect of any Construction Loan Advance or Term Loan Advance within five (5) Business Days after the same becomes due and payable;

(ii) if the Borrower reaches or exceeds its updated debt and financial obligation limit imposed by its by-laws or any resolution of its Board of Directors;

(iii) if the Borrower has failed to pay principal of or interest on any Indebtedness other than the Construction Loan Advances or Term Loan Advances issued under this Agreement when due and such default continues for five (5) Business Days;

(iv) if the Borrower has failed to meet and pay any of its liabilities and obligations other than Indebtedness when due and default in payment is occasioned from financial difficulties affecting the Borrower;

(v) if the Borrower has become involved in financial difficulties such that default or unusual difficulty in meeting debts or obligations or in providing adequate funds to meet current expenditures may ensue;

(vi) if the Borrower uses any Advance or the proceeds of any Term Loan for any purpose other than financing the Project(s);

(vii) if the Borrower takes any action to authorize the termination of the existence of the Borrower or a resolution is passed authorizing the termination of the existence of the Borrower, unless such action or resolution is being pursued by the Borrower on the basis that it has made provision for payment of all of its

Indebtedness including all of the Advances issued under this Agreement, that no court proceedings are pending against it and that it has obtained the approval of its creditors to a plan for the rateable distribution of all of its property;

(viii) if the Borrower is subject to any proceeding whereby such proceeding shall be instituted against the Borrower or applying to a substantial part of its property or assets seeking to adjudicate it a bankrupt or insolvent, or seeking liquidation, dissolution, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or any substantial part of its property or debt under any law relating to bankruptcy, insolvency or reorganization or relief of debts, or seeking an order for relief or the appointment of a receiver, trustee or other similar official for it or for any substantial part of its property and such proceeding shall have continued undismissed or unstayed for 60 days, or a creditor or creditors of the Borrower shall privately appoint a receiver, trustee or similar official for any substantial part of the property of the Borrower and, if the Borrower shall be contesting such appointment in good faith, such appointment shall continue for 90 days; or any such action or proceeding shall have been consented to or not expeditiously opposed by the Borrower;

(ix) if the Borrower shall fail to observe or perform any covenant or condition contained herein (other than a covenant or condition whose breach or default in performance is elsewhere in this paragraph 9(c) specifically dealt with) and the Borrower shall not make good such default within a period of thirty (30) days after written notice has been given to the Borrower by OILC;

(x) if the representations and warranties made by the Borrower in this Agreement or the Application, or in any certificate or other document delivered hereunder shall be incorrect in any material respect when made and, if such incorrect representation or warranty is curable, the Borrower shall fail to make good such default within a period of thirty (30) days after notice in writing has been given to the Borrower by OILC;

(xi) if issues raised in an audit required under paragraph 19(a) have not been resolved to OILC's satisfaction within a reasonable time after the Borrower has been notified of such issues;

(xii) if the report of the auditors on any annual financial statements delivered pursuant to this Agreement or any other financial information requested by OILC delivered pursuant to this Agreement hereof shall be qualified in any way which OILC, acting reasonably deems to be materially adverse or if the Borrower should fail to supply any documents requested pursuant to this Agreement;

(xiii) if any final judgment is obtained against the Borrower for an amount in excess of $100,000 and, within 10 days of the obtaining thereof, such judgment has not been discharged or execution thereunder stayed;

(xiv) if at any time any licence or approval required by the Borrower under any Applicable Law or from any Public Authority to carry on its business has been assigned, cancelled or suspended; and

(xv) if the Borrower shall enter into any Indebtedness which is senior to any Indebtedness to OILC, other than as permitted under this Agreement, without the prior written consent of OILC.

(d) If OILC elects to terminate its obligations under this Agreement pursuant to paragraph 9(c), it shall give notice in writing of such termination to the Borrower, specifying the reason for such termination. Upon delivery of such notice OILC shall have no further obligation to make any Advances hereunder. In such notice OILC may also declare all Obligations outstanding hereunder to be immediately due and payable, whereupon such Obligations shall become immediately due and payable; and OILC may exercise any rights or remedies it may have at law or in equity to enforce such Obligations.

(e) No delay on the part of OILC in exercising any remedy and no waiver by OILC of any of its rights against the Borrower shall operate as a waiver of any other rights nor shall any single or partial exercise of any remedy against the Borrower restrict other or further exercises of such remedy, all remedies being cumulative and not exclusive.

(f) If OILC elects to terminate its obligations under this Agreement in accordance with paragraphs 9(b) or 9(c) above, the Borrower shall pay to OILC the Make-Whole Amount on account of the losses that it will incur as a result of the full repayment or early termination.

10. SUCCESSOR CORPORATIONS

The Borrower may:

(a) amalgamate, merge, consolidate or otherwise combine pursuant to statute or by private agreement with any other Person, or

(b) sell, lease or otherwise dispose of all or substantially all of its assets, rights and properties, whether in a single transaction or a series of related transactions, to any other Person;

provided, in either case that:

(i) the resulting or acquiring entity (the "**Successor Entity**") is a body corporate existing and organized under the laws of Canada or any province or territory thereof;

(ii) the Successor Entity is an Eligible Borrower;

(iii) the Successor Entity expressly assumes the due and punctual payment of the principal of, and all interest on, all Advances (including Term Loan Advances) and all other amounts owing hereunder and the performance and observance of all of the covenants and conditions of this Agreement on the part of the Borrower to be performed;

(iv) the Successor Entity delivers an opinion acceptable to counsel for OILC, acting reasonably, to the effect that the Successor Entity has validly assumed such obligations; and

(v) no Event of Default shall have occurred or be continuing as of the effective date of each such transaction or shall arise as of the effective date of each such transaction and as a result thereof, and the Borrower shall have provided OILC with an Officer's Certificate to such effect.

11. NON-WAIVER

Any failure of OILC to object to or take action with respect to a breach of this Agreement or any OILC Security or upon the occurrence of an Event of Default shall not constitute a waiver of OILC's right to take action at a later date with respect to such breach. No course of conduct by OILC will give rise to any reasonable expectation which is in any way inconsistent with the terms and conditions of this Agreement and the OILC Security and OILC's rights thereunder.

12. EVIDENCE OF INDEBTEDNESS

OILC shall open and maintain in accordance with its usual practice books of account evidencing all Advances and all other amounts owing by the Borrower to OILC. OILC shall enter in the foregoing accounts details of each Advance and of all amounts from time to time owing or paid by the Borrower to OILC hereunder, the amounts of principal, interest and fees payable from time to time hereunder. The information entered in the foregoing accounts shall constitute, in the absence of manifest error, prima facie evidence of the obligations of the Borrower to OILC hereunder, the date OILC made each Advance to the Borrower and the amounts the Borrower has paid from time to time on account of the principal of, interest on and fees related to the Advances. For each Term Loan Advance, the Borrower shall provide a promissory note in favour of OILC which shall include the scheduled dates for principal repayment and interest payments.

13. ENTIRE AGREEMENT

This Agreement, together with the Schedules, the Drawdown Certificate, the Officer's Certificates delivered hereunder, and the mortgage/charge and OILC Security constitute the entire agreement between the parties with respect to the subject matter referenced in those documents and supersedes all prior agreements, negotiations, discussions, undertakings, representations, warranties and understandings, whether written or oral.

14. ASSIGNMENT

The Borrower may not assign its rights or transfer its obligations under this Agreement without the prior written consent of OILC. OILC may assign its rights or transfer its obligations under this Agreement without the prior written consent of the Borrower by giving thirty (30) days notice of such assignment or transfer to the Borrower. This Agreement enures to the benefit of and binds the parties and their respective successors and permitted assigns.

15. INDEMNITY

(a) To the fullest extent permitted by law, the Borrower shall indemnify and hold harmless OILC, its officers, directors, employees and agents (the "**Indemnified Parties**") from and against all (i) claims and causes of action, pending or threatened, of any kind (whether based in contract, tort or otherwise) by third parties or by whomever made related to or arising out of or in any way related to the Reports, this Agreement or the Project and (ii) liabilities, losses, damages, costs and expenses (including, without limitation, legal fees and disbursements) suffered or incurred by any of the Indemnified Parties in connection with any claims or causes of action described in (i) above in this paragraph. The obligations contained in this paragraph shall survive the termination or expiry of this Agreement.

(b) Reports submitted by the Borrower to OILC are for OILC's reference only and in no way shall OILC, its officers, directors, agents, subcontractors, or employees be held responsible or liable at law for: (a) any claim, demand or action brought forward by any party, including third parties, against OILC; and (b) direct or indirect consequential damages, including bodily injury, death or property damages, arising out of or in any way related to the Reports, this Agreement or the Project.

16. COMMUNICATIONS REQUIREMENTS

(a) OILC and the Borrower will work together to ensure that OILC financing of the Project receives recognition and prominence through agreed upon communications activities. An example of such activity could include signage at the project site signifying Government of Ontario project financing.

(b) OILC reserves the right to undertake its own communications activities in relation to OILC financing of the Project at anytime in its sole discretion and at its expense. This may include, but is not limited to, disclosure of the Borrower and the loan amount hereunder to a third party.

(c) All joint communications activities between the Borrower and OILC must comply with the Government of Ontario's Visual Identity Directive and guidelines.

17. CONFIDENTIALITY AND RELEASE OF INFORMATION

(a) The Borrower agrees that OILC may provide any assignee with any information concerning the financial condition of the Borrower.

(b) Subject to paragraph17(a), OILC acknowledges the confidential nature of the financial, operational and other information and data provided and to be provided to it by the Borrower pursuant to this Agreement (the "**Information**") and agrees to use all reasonable efforts to prevent its disclosure provided, however, that:

   (i) it may disclose all or any part of the Information if, in its opinion, such disclosure is required in connection with any actual or threatened judicial, administrative or governmental proceeding; and

(ii) it shall incur no liability in respect of any disclosure of Information to any, or pursuant to the requirements of any, judicial authority, law enforcement agency or taxation authority.

(c) The Borrower acknowledges that OILC is an institution to which the *Freedom of Information and Protection of Privacy Act (Ontario)* ("**FIPPA**") applies and in the event of an access request under FIPPA for records in the control of OILC that may be in the possession of the Borrower, the Borrower will co-operate in identifying, copying and returning such records to OILC. The Borrower agrees that if it collects or receives Personal Information (as such term is defined in FIPPA) it will only do so, and it will only use, disclose or destroy such information, in accordance with the provisions of FIPPA relating to Personal Information in the custody or control of OILC to which FIPPA applies.

18. <u>FURTHER ASSURANCES</u>

The Borrower shall from time to time and at all times hereafter, upon every reasonable request of OILC, make, do, execute, and deliver or cause to be made, done, executed and delivered all such further acts, deeds, assurances and things as may be necessary in the opinion of OILC acting reasonably for more effectually implementing and carrying out the true intent and meaning of this Agreement.

19. <u>MISCELLANEOUS</u>

(a) OILC reserves the right to audit compliance with this Agreement at any time. Such right will survive any termination of this Agreement. The cost of any such audit will be at OILC's or the Borrower's expense at OILC's discretion. The Borrower is required to keep any supporting documents required for any such audit for a minimum of seven (7) years.

(b) No amendment, supplement, restatement or termination of any provision of this Agreement is binding unless it is in writing and signed by each party.

(c) This Agreement is governed by, and is to be construed and interpreted in accordance with, the laws of the Province of Ontario and the federal laws of Canada applicable in the Province of Ontario.

(d) This Agreement and any amendment, supplement, restatement or termination of any provision of this Agreement may be executed and delivered in any number of counterparts, each of which when executed and delivered is an original but all of which taken together constitute one and the same instrument.

(e) Either party may deliver an executed copy of this Agreement by fax but that party shall immediately deliver to the other party an original executed copy of this Agreement.

(f) Unless otherwise specified, each notice to a party must be given in writing and delivered personally or by courier, sent by prepaid registered mail or transmitted by fax to the address, or fax number address set out below:

(i) Ontario Infrastructure and Lands Corporation
777 Bay Street, 9th Floor
Toronto, Ontario M5G 2C8

Attn: Director, Loans Operations
Tel.: 416-326-1149
Fax: 416-212-6452

(ii) Brantford Power Inc.
84 Market Street, 3rd Floor
Brantford, ON N3T 5N8

Attn: Chief Financial Officer
Tel.: 519-759-4222 Ext. 3234
Fax: 519-753-4130

Any notice so mailed shall be deemed to have been received on the fifth Business Day next following the registered mailing of such notice, provided that postal service is in normal operation during such time. Any notice delivered by courier, or personal delivery shall be deemed to have been received on the Business Day that it was delivered. Any facsimile notice shall be deemed to have been received on transmission (and receipt of confirmation of transmission) if sent by any party to this Agreement before 4:00 p.m. Toronto time on a Business Day and, if not, on the next Business Day following transmission.

(g) If any provision of this Agreement is or becomes illegal, invalid or unenforceable in any jurisdiction, the illegality, invalidity or unenforceability of that provision will not affect:

(i) the legality, validity or enforceability of the remaining provisions of this Agreement; or

(ii) the legality, validity or enforceability of that provision in any other jurisdiction.

(h) All covenants, agreements, representations and warranties made herein or in any document delivered pursuant to the provisions hereof are material, shall be deemed to have been relied upon by each party hereto and, notwithstanding any investigation heretofore or hereafter made by such party shall survive the execution and delivery of this Agreement until all amounts owing pursuant to the provisions hereof have been paid in full.

(i) Words importing the singular include the plural and vice versa.

20. DEFINITIONS

Capitalized terms used in this Agreement shall have the following meanings:

"**Acquired Assets**" means any assets, rights or properties, of any nature or kind, acquired, constructed or improved by the Borrower or any Related Entity after the date of this Agreement and, for greater certainty, shall include any buildings or other fixtures, acquired, constructed or improved by the Borrower after the date of this Agreement.

"**Act**" means the *Business Corporations Act (Ontario),* as amended, supplemented or replaced from time to time.

"**Advance**" means a Construction Loan Advance or a Term Loan Advance, as applicable.

"**Advance Interest Rate**" has the meaning given to it in paragraph 1(a) hereof.

"**Agreement**" means the agreement constituted by this agreement including all attached schedules and referenced documents including the general security agreement, charge/mortgage, assignment of rents, guarantee, assignment of construction rights agreement and the respective terms and conditions thereunder, as the same may be amended, restated, modified or replaced from time to time. Terms such as "hereof", "herein" and "hereto" refer to this Agreement.

"**Applicable Law**" means, in respect of any Person, property, transaction or event, all present or future applicable laws, statutes, regulations, treaties, judgments and decrees and all present or future applicable published directives, rules, policy statements, construction building codes, instruments and orders of any Public Authority and all applicable orders and decrees of courts and arbitrators of like application.

"**Application**" means the OILC loan application number 11070 of the Borrower.

"**Authorized Officer**" means with respect to the Borrower, the Chief Executive Officer, Secretary-Treasurer, Chairperson, Vice-Chairperson or any other officer or Person designated from time to time by a resolution of the Board of Directors of the Borrower.

"**Business Day**" means a day on which banking institutions in Toronto, Ontario, Canada are not authorized or obligated by law or executive order to be closed, other than Saturday or Sunday.

"**Canada Yield Price**" on any date (which in the case of any calculation of the Make-Whole Amount hereunder shall be the fifth Business Day prior to the applicable termination date) means a price, in respect of any principal amount outstanding on such date, necessary to provide a yield to maturity on such principal amount from such date to the Facilities Maturity Date equal to the Government of Canada Yield on such date.

"**Capital Lease Obligations**" of any Person means the obligations of such Person to pay rent or other amounts under any lease of (or other arrangement conveying the right to use) real or personal property, or a combination thereof, which obligations are required to be classified and accounted for as capital leases on a balance sheet of such Person under GAAP and the amount of such obligations shall be the capitalized amount thereof determined in accordance with GAAP.

"**CLA**" means the *Construction Lien Act*, R.S.O. 1990, c.30, as amended, supplemented or replaced from time to time.

"**Committed Amount**" means the aggregate principal amount of $4,000,000.00 committed by OILC to be made available to the Borrower subject to the terms and conditions of the Agreement.

"**Construction Loan**" means, at any time, the aggregate of all Advances made, or deemed to be made, by or on behalf of OILC to or on behalf of the Borrower under the credit facility established pursuant to Section 1(a) of Schedule A which remain unpaid or outstanding at such time.

"**Construction Loan Advance**" means a short-term loan under the Construction Facility made by OILC to the Borrower in Canadian dollars pursuant to the terms and conditions of this Agreement.

"**Construction Loan Maturity Date**" means December 31, 2012, subject to acceleration by OILC pursuant to the terms hereof.

"**Construction Period**" means the period commencing on the date of the Initial Drawdown and ending on the Construction Loan Maturity Date.

"**Conversion Date**" means the earlier of December 31, 2012, as such date may be extended by OILC in its sole discretion, and the date as of which the Borrower elects to convert the Construction Loan to the Term Loan in accordance with the provisions of Section 1(b) of Schedule A;

"**Conversion Notice**" means a notice substantially in the form set out in Schedule "D".

"**Current Ratio**" is defined as current assets divided by current liabilities. Current assets shall exclude any loans and accounts receivable due from related companies, subsidiaries, officers, and employees that have no fixed term of repayment.

"**Debt to Capitalization Ratio**" is defined as Debt divided by total Capitalization, where:

> "Debt" means all short-term and long-term interest-bearing debt but excluding debt that is subordinate to OILC's loans.
>
> "Capitalization" means all Debt and any debt that is subordinate to OILC's loans plus shareholder's net worth which is defined as the sum of share capital, preferred shares and retained earnings minus advances and/or investments to/in affiliated or related companies or third party entities minus goodwill and other intangible assets including future income tax assets.

"**Debt Service Coverage Ratio**" is defined as Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA) excluding extraordinary items minus 40% of Net Capital Expenditures divided by the sum of principal and interest payments made on all interest-bearing debts, during the fiscal year in question.

DSCR = (EBITDA– 40% of Net Capital Expenditures) / (Principal + Interest)

"Drawdown Certificate" means a certificate substantially in the form as provided by OILC to the Borrower.

"Drawdown Notice" means a notice in the form of Schedule C delivered in accordance with Section 2(a).

"Eligible Borrower" means a public body that is eligible to borrow from OILC pursuant to the *Ontario Infrastructure and Lands Corporation Act, 2011* (Ontario).

"Event of Default" means any of the events described in paragraph 9(c).

"Facilities Maturity Date" means December 31, 2042, subject to acceleration by OILC pursuant to the terms hereof.

"Financial Instrument Obligations" means all obligations and liabilities of the Borrower or a Related Entity under or in respect of any interest or currency rate swap, forward agreement or other instrument which is a financial derivative.

"Fiscal Quarter" means the fiscal quarter of the Borrower ending on March 31, June 30, September 30 and December 31, as applicable, in each calendar year.

"Fiscal Year" means the fiscal year of the Borrower ending on December 31 in each calendar year.

"GAAP" means those generally accepted accounting principles consistently applied in Canada and, following the adoption of IFRS by the Borrower, means IFRS.

"Governmental Authority" means any federal, provincial, state, municipal or local government, parliament or legislature, or any regulatory authority, agency, tribunal, commission, board or department of any government, parliament or legislature, or any court or other law, regulation or rule-making entity, having or purporting to have jurisdiction in the relevant circumstances, including the Ontario Electricity Financial Corporation.

"Government of Canada Yield" on any date means the arithmetical average of the yield to maturity on such date, assuming semi-annual compounding, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity equal to the remaining term of the Facilities hereunder from the termination date to the Facilities Maturity Date quoted at 10:00 a.m. (Toronto time) by two major Canadian investment dealers selected by OILC from Scotia Capital Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc. and TD Securities Inc. or any of their successors and any other investment dealer approved for such purpose by OILC.

"Hazardous Materials" means any substance, material or waste regulated, listed or prohibited by environmental laws including, without limitation: (i) any substance, material or waste that is (a) petroleum, (b) asbestos, (c) polychlorinated biphenyls, (d) flammable explosives or (e) radioactive materials.

"**Holdback Amount**" means an amount equal to the amount of the holdback or holdbacks required by the CLA (which is currently an amount equal to 10% of the price of all services or materials as they are actually supplied under the construction agreements under which a lien may arise) which the Borrower, at the time of determination:

(i) was required under the CLA to have retained from previous payments made pursuant to any provisions of any construction agreement or other agreement pursuant to which a lien under the CLA could arise against the Project; and

(ii) will be required under the CLA to retain from any payment currently due or about to become due pursuant to any construction agreement or other agreement whether or not such payment is made from funds loaned by OILC to the Borrower;

"IESO" means the Independent Electricity System Operator.

"**IFRS**" means the International Financial Reporting Standards.

"**Indebtedness**" means, at any time and in respect of any Person, without duplication:

(i) all obligations of such Person for money borrowed including:

(A) obligations with respect to bankers' acceptances;

(B) contingent reimbursement obligations with respect to letters of credit and other financial instruments; and

(C) all Purchase Money Obligations which would be indebtedness under GAAP but excluding, for greater certainty, trade indebtedness accounted for as accounts payable, accrued expenses and other similar current liabilities incurred in the ordinary course of operations determined in accordance with GAAP;

(ii) any Capital Lease Obligation of such Person; and

(iii) all undertakings of such Person in respect of obligations of any Person of the type described in (i) which such Person has guaranteed, directly or indirectly, or the holder of which such Person has otherwise assured against loss thereon.

"**Independent Insurance Consultant**" or "**Insurance Consultant**" means an insurance consultant appointed by OILC pursuant to this Agreement.

"**Initial Drawdown**" means the initial Drawdown of funds by the Borrower under the Construction Loan made subject to and in accordance with the terms of this Agreement;

"**Interest Period**" for a Construction Loan Advance means: (i) initially, the period from and including the date of the Construction Loan Advance to but excluding the next following Reset

Date; and (ii) subsequently, each period from and including a Reset Date to but excluding the next following Reset Date.

"**Liens**" means mortgages, pledges, liens, hypothecs, charges, security agreements or other encumbrances or other arrangements that in substance secure payment or performance of an obligation, statutory and other non-consensual liens or encumbrances and includes the interest of a vendor or lessor under any conditional sale agreement, capital lease or other title retention agreement.

"**Limited Recourse Debt**" means Indebtedness, under which recourse in respect of a default in the repayment of such Indebtedness is limited to the asset or assets acquired with such Indebtedness by the Borrower or any Related Entity.

"**Make-Whole Amount**" in respect of the aggregate principal amount of all the outstanding Term Loan Advances means the positive amount, if any, by which (i) the Canada Yield Price for such principal amount exceeds (ii) such principal amount.

"**Material Related Entity**" means, at any relevant time, any Related Entity, the book value of whose assets, rights and properties constitutes in excess of 10% of the book value of the assets, rights and properties of the Borrower and all its Related Entities, considered as a whole.

"Net Capital Expenditures" are the capital expenditures in the period less the proceeds from sale of property, plant and equipment and other fixed assets in the normal course of business, and less the amount of such capital expenditures financed by contributed capital by the shareholder or other entities.

"**Obligations**" means the amount of all Advances provided to the Borrower pursuant to this Agreement and any unpaid interest thereon.

"OEB" means the Ontario Energy Board or its successor.

"**Officer's Certificate**" means a certificate of the Borrower that has been signed by an Authorized Officer.

"Permitted Annual Distribution Limit" means the Borrower's net cash balance as at the last day of the applicable fiscal year. The Borrower's net cash balance is defined as cash or cash equivalent minus the outstanding balance on the Borrower's operating line of credit.

"**Permitted Liens**" means and refers to:

(i) Liens to which any Acquired Assets are subject at the time such Acquired Assets are acquired by the Borrower or any Related Entity provided that such Lien is limited to the Acquired Assets and such Lien has not been created or incurred in anticipation of such acquisition;

(ii) any Lien on or against cash or marketable debt securities to secure Financial Instrument Obligations incurred by the Borrower or any Related Entity in the course of its operations and not for speculative purposes;

(iii) any Lien in respect of a Purchase Money Obligation, Capital Lease Obligation or Limited Recourse Debt incurred in connection with or within 180 days of the acquisition, construction or improvement of any Acquired Assets and which secures the purchase price of such asset or the cost of acquiring, constructing or improving such asset provided that the amount secured by such Lien does not exceed the purchase price or cost of acquiring, constructing or improving such asset (including any applicable interest and/or lease payments to be paid);

(iv) any Liens to which assets acquired or which are deemed to have been acquired by the Borrower or any Related Entity pursuant to a merger or other combination with any other entity are subject at the time of such merger or other combination;

(v) Liens for Taxes, utility charges, levies, assessments or governmental charges:

(A) not at such time past due; or

(B) the validity of which are being contested in good faith and by appropriate proceedings;

(vi) the Lien of any judgment rendered, or claim filed, which is being contested in good faith and by appropriate proceedings;

(vii) undetermined or inchoate Liens and charges incidental to, purchases of goods, construction, maintenance or current operations which have not at such time been filed or registered pursuant to law, which relate to obligations which are at such time not past due or which, if filed or registered, are being contested in good faith and by appropriate proceedings;

(viii) easements, rights-of-way, servitudes or other similar rights in property (including rights-of-way and servitudes for railways, sewers, drains, gas and oil pipe lines, gas and water mains, electric light and power and telephone or telegraph or cable television conduits, poles, wires and cables) granted to or reserved or taken by other Persons;

(ix) security given to a public utility or any municipality or governmental or other public authority when and to the extent required by such utility or municipality or other authority in the ordinary course of operations of the Borrower or any Related Entity and not in connection with the borrowing of money or obtaining of credit by the Borrower or any Related Entity;

(x) the right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, license, franchise, grant or permit, or by any statutory provision, to terminate any such lease, license, franchise, grant or permit, or to require annual or other periodic payments as a condition of the continuance thereof;

(xi) the reservation in any original grant from the Crown of any land or interests therein and statutory exceptions to title;

(xii) Liens created or assumed by the Borrower or any Related Entity if an Authorized Officer has certified to OILC that such Liens secure amounts which are not material having regard to the then current market value of the assets, rights and properties of the Borrower and its Related Entities, considered as a whole;

(xiii) any renewal, replacement or temporal extension (or successive renewals, replacements or extensions) in whole or in part of any Permitted Lien so long as the principal amount secured by such Permitted Lien does not exceed the principal amount secured by the Permitted Lien immediately prior to such extension; and

(xiv) any and all Liens, whether direct or indirect, contingent or otherwise, to which any of the assets, rights and properties of the Borrower and its Related Entities are subject on the date of this Agreement.

"**Person**" means an individual, company, partnership (whether or not having separate legal personality), corporation (including a business trust), joint stock company, trust, unincorporated association, joint venture, income fund or other entity, or a government, state or political subdivision thereof or any agency of such government, state or political subdivision.

"**Premises**" means all locations where the Borrower undertakes the Project.

"**Prime Rate**" means, on any day, the annual rate of interest which is the arithmetic mean of the prime rates announced from time to time by the Reference Banks as their reference rates in effect on such day for Canadian dollar commercial loans made in Canada. If fewer than five of the Reference Banks quote a prime rate on such days, the "Prime Rate" shall be the arithmetic mean of the rates quoted by the remaining Reference Banks.

"**Project**" means the Borrower's 2011 General Capital Spending Program.

"**Project Monitor**" means a Person who has been engaged by the Borrower, at Borrower's cost and expense, to provide independent project monitor reports with respect to the Project to OILC on a timely basis and to confirm that that the Project budget is sufficient to complete the Project; the Project Monitor shall be acceptable to OILC and shall have one or more principals who are Professional Quantity Surveyors in good standing of the Canadian Institute of Quantity Surveyors.

"**Public Authority**" means any governmental, regional, municipal or local body having authority over either of OILC or the Borrower.

"**Purchase Money Obligation**" means any unpaid part of, or indebtedness incurred or assumed for the purpose of acquiring, a particular asset, right or property, the repayment of which is secured by recourse against such asset, right or property.

"**Reference Banks**" means, collectively, The Toronto-Dominion Bank, Bank of Nova Scotia, Bank of Montreal, Royal Bank of Canada and Canadian Imperial Bank of Commerce.

"**Related Entity**" means any company, corporation, partnership or other entity which is controlled by the Borrower either through the ownership of voting securities, by contract or otherwise.

"**Reports**" means the project management reports and any other project monitoring reports provided by the Project Monitor for and on behalf of the Borrower pursuant to this Agreement.

"**Reset Date**" has the meaning given to it in paragraph 1(a)(i) of this Schedule "A".

"**Taxes**" means any present or future income, property, land transfer, municipal, local improvement, transfer, excise, goods and services, harmonized sales, sales, retail, excise, value-added, turnover, stamp, customs, countervail, anti-dumping, import and export, taxes, levies, charges, duties and assessments, including all payments in lieu thereof, special payments, fees, premiums, imposts, rates, withholdings, dues, Canada Pension Plan contributions, Employment Insurance Act premiums, payroll taxes, government contributions and other charges or taxes of any kind whatsoever, whether direct or indirect, together with all interest, penalties, fines, additions thereto or other additional amounts, imposed by any Governmental Authority.

"**Term Loan Advance**" means a long-term loan under the Term Facility made or deemed to be made by OILC to the Borrower in Canadian dollars pursuant to the terms and conditions of this Agreement.

SCHEDULE "E"

GENERAL SECURITY AGREEMENT

TO: ONTARIO INFRASTRUCUTRE AND LANDS CORPORATION

The undersigned **BRANTFORD POWER INC.** (hereinafter called the "Debtor") hereby enters into this General Security Agreement with **ONTARIO INFRASTRUCTURE AND LANDS CORPORATION** (hereinafter called the "Secured Party") for valuable consideration and as security for the repayment of the principal sum of $4,000,000.00, loaned to the Debtor by the Secured Party pursuant to a Financing Agreement dated November 6, 2012 together with interest and all expenses (including legal fees on a solicitor and client basis) incurred by the Secured Party, its receiver or agent in the enforcement of security or other agreements held by the Secured Party in respect of such indebtedness or liabilities (which indebtedness and liabilities, and interest thereon, as provided herein, are herein collectively called the "Indebtedness").

A. GRANT OF SECURITY INTERESTS

1. The Debtor hereby grants to the Secured Party, by way of mortgage, charge, assignment and transfer a security interest in the undertaking of the Debtor and in all Goods (including all attachments, additions and accessions thereto), Chattel Paper, Documents of Title (whether negotiable or not), Instruments, Intangibles, Money and Securities now or hereafter owned or acquired by or on behalf of the Debtor and in all proceeds and renewals thereof, accretions thereto and substitutions therefor (hereinafter collectively called the "Collateral"), including, without limitation, all of the following now or hereafter owned or acquired by or on behalf of the Debtor:

(a) all inventory of whatever kind and wherever situate ("Inventory");

(b) all equipment (other than Inventory) of whatever kind and wherever situate including, without limitation, all machinery, tools, apparatus, plant, furniture, fixtures and vehicles of whatsoever nature or kind;

(c) all accounts and book debts and generally all debts, dues, claims, choses in action and demands of every nature and kind howsoever arising or secured including letters of credit, guarantees and advice of credit which are now due, owing or accruing or growing due to or owned by or which may hereafter become due, owing or accruing or growing due to or owned by the Debtor ("Debts");

(d) all contractual rights and insurance claims and all goodwill, patents, trademarks, copyrights and other industrial property;

(e) all monies other than trust monies lawfully belonging to others;

(f) all other property and assets, real and personal, movable or immoveable, of whatsoever nature and kind.

2. The mortgages, charges and security interests hereby created shall not extend or apply to the last day of the term of any lease, oral or written, or agreement therefor, now held or hereafter acquired by the Debtor, but upon the enforcement of the Security Interest the Debtor shall stand possessed of such last day in trust to assign and dispose of the same to any person acquiring such term. There shall also be excluded from the security created by this General Security Agreement any property of the Debtor that constitutes consumer goods for the personal use of the Debtor.

B. ATTACHMENT

3. The Debtor warrants and acknowledges that the Debtor and the Secured Party intend each of the security in this General Security Agreement in existing Collateral to attach upon the execution of this General Security Agreement; that value has been given; that the Debtor has rights in such existing Collateral; and that the Debtor and the Secured Party intend the security interests in this General Security Agreement in hereafter acquired Collateral to attach at the same time as the Debtor acquires rights in the said after acquired Collateral.

C. REPRESENTATIONS AND WARRANTIES OF DEBTOR

4. The Debtor hereby represents and warrants to the Secured Party that:

(a) The Debtor has or expects hereafter to have assets at the location(s) set out in Schedule "A";

(b) The Collateral is primarily situate or located at the location(s) set out in Schedule "A" on the date hereof but may from time to time be located at other premises of the Debtor; may also be located at other places while in transit to and from such locations and premises; and may from time to time be situate or located at any other place when on lease or consignment to any lessee or consignee from the Debtor;

(c) The Collateral is genuine and owned by the Debtor free of all security interests, mortgages, liens, claims, charges or other encumbrances, save for the security interest created by this General Security Agreement.

D. COVENANTS AND AGREEMENTS OF DEBTOR

5. The Debtor hereby covenants and agrees with the Secured Party that until all of the Indebtedness is paid in full:

(a) The Debtor shall not without the prior written consent of the Secured Party sell or dispose of any of the Collateral in the ordinary course of business or otherwise, and if the amounts of any of the Collateral referred to in paragraph 1 hereof shall be paid to the Debtor, the Debtor shall receive the same in trust for the Secured Party and forthwith pay over the same to the Secured Party upon request; provided however that Inventory may be sold or disposed of in the ordinary course of business and for the purpose of carrying on the same;

(b) The Debtor shall not without the prior written consent of the Secured Party create or permit any liens upon or assign or transfer as security or pledge or hypothecate as security or create a security interest in the Collateral except to the Secured Party;

(c) The Debtor shall at all times have and maintain insurance over the Collateral against risks of fire (including extended coverage), theft, and such risks as the Secured Party may reasonably require in writing, containing such terms, in such form, for such periods and written by such companies as may be reasonably satisfactory to the Secured Party. The Debtor shall duly and seasonably pay all premiums and other sums payable for maintaining such insurance and shall cause the insurance money thereunder to be payable to the Secured Party as its interest hereunder may appear and shall, if required, furnish the Secured Party with certificates or other evidence satisfactory to the Secured Party of compliance with the foregoing insurance provisions. In the event that Debtor fails to pay all premiums and other sums payable in accordance with the foregoing insurance provision the Secured Party may make such payments to be repayable by the Debtor on demand and any such payments made by the Secured Party shall be secured hereby;

(d) The Debtor shall keep the Collateral in good condition and repair according to the nature and description thereof, and the Secured Party may, whenever it deems necessary, either in person or by agent, inspect the Collateral and the reasonable cost of such inspection shall be paid by the Debtor and secured hereby and the Secured Party may make repairs as it deems necessary, and the cost thereof shall be paid by the Debtor and secured hereby;

(e) The Debtor shall duly pay all taxes, rates, licence fees and other charges assessed or imposed upon it or the Collateral, or any part thereof and upon the income and profit of the Debtor. In the event that the Debtor fails to pay any taxes as they come due, the Secured Party may make payments in respect of any unpaid taxes to be repayable by the Debtor on demand and any such payments made by the Secured Party shall be secured hereby; and

(f) The Debtor agrees that the Secured Party may require any account debtor of the Debtor to make payment to the Secured Party and the Secured Party may take control of the proceeds referred to in paragraph 1 hereof and may hold all amounts received from any account debtor and any proceeds as cash collateral as part of the Collateral and as security for the Indebtedness.

6. The Debtor shall at all times and from time to time do, execute, acknowledge and deliver or cause to be done, executed, acknowledged or delivered all and singular every such further act, deed, transfer, assignment, assurance, document or instrument as the Secured Party may reasonably require for the better granting, transferring, assigning, charging, setting over, assuring and confirming unto the Secured Party the property and assets hereby mortgaged, charged or subjected to security interests or intended so to be or which the Debtor may hereafter become bound to mortgage, charge, transfer, assign or subject to a security interest in favour of the Secured Party and for the better accomplishing and effectuating of this General Security Agreement and the provisions contained herein and every officer of the Secured Party and each of them is irrevocably appointed attorneys or attorney to execute in the name and on behalf of the Debtor any document or instrument for the said purposes.

7. The Debtor shall permit the Secured Party at any time, either in person or by agent, to inspect the Debtor's books and records pertaining to the Collateral including, without limiting the generality of the foregoing, inventory, accounts and contract rights. The Debtor shall at all times upon request by the Secured Party furnish the Secured Party with such information concerning the Collateral and the Debtor's affairs and business as the Secured Party may reasonably request, including lists of inventory and equipment and lists of accounts receivable showing the amounts owing upon each account and securities

therefor and copies of all financial statements, books and accounts, invoices, letters, papers and other documents in any way evidencing or relating to the account.

8. The Debtor acknowledges and agrees that in the event it amalgamates with any other corporation or corporations it is the intention of the parties hereto that the security interest created hereby:

(a) shall extend to "Collateral" (as that term is herein defined) owned by each of the amalgamating corporations and the amalgamated corporation at the time of amalgamation and to any "Collateral" thereafter owned or acquired by the amalgamated corporation, such that the term "Debtor" when used herein would apply to each of the amalgamating corporations and the amalgamated corporation and;

(b) shall secure the "Indebtedness" (as that term is herein defined) of each of the amalgamating corporations and the amalgamated corporation to the Secured Party at the time of amalgamation and any "Indebtedness" of the amalgamated corporation to the Secured Party thereafter arising.

The security interest shall attach to the additional "Collateral" at the time of amalgamation and to any "Collateral" thereafter owned or acquired by the amalgamated corporation when such becomes owned or is acquired.

E. DEFAULT

9. The Debtor shall be in default under this General Security Agreement upon the occurrence of any one of the following events:

(a) the non-payment by the Debtor, when due, whether by acceleration or otherwise, of any of the Indebtedness;

(b) the failure of the Debtor to observe or perform any material covenant, undertaking or agreement heretofore or hereafter given to the Secured Party, whether contained herein or not, if such failure is not rectified within thirty (30) days after written notice from the Secured Party;

(c) an execution or any other process of the Court becomes enforceable against the Debtor or a distress or an analogous process is levied upon the property of the Debtor or any part thereof;

(d) if the Debtor shall become insolvent or shall make a bulk sale of all or substantially all of its assets or a general assignment for the benefit of creditors or a proposal under the Bankruptcy and Insolvency Act or if a bankruptcy or similar petition with respect to bankruptcy, insolvency or other enforced liquidation of the Debtor shall be filed or presented (unless the same is dismissed, appealed or discharged within 15 days of its institution) or if a custodian or a sequestrator or a receiver or a receiver and manager or any other officer with similar powers shall be appointed of the Debtor or any of its property or any part thereof;

(e) if any proceedings are commenced with respect to the Debtor under the Companies Creditors Arrangement Act or any successor or similar legislation;

(f) the Debtor ceases or threatens to cease carrying on its business or if a petition shall be filed, an order shall be made or an effective resolution be passed for the winding-up, dissolution or liquidation of the Debtor; or

(g) the Debtor defaults in the observance or performance of any provision relating to indebtedness of the Debtor to any creditor other than the Secured Party and thereby enables such creditor to demand payment of such indebtedness.

10. The Secured Party may in writing waive any breach by the Debtor of any of the provisions contained herein or any default by the Debtor in the observance or performance of any covenant or condition required by the Secured Party to be observed or performed by the Debtor; provided that no act or omission by the Secured Party in the premises shall extend to or be taken in any manner whatsoever to affect any subsequent breach or default or the rights resulting therefrom.

F. REMEDIES OF THE SECURED PARTY

11. (a) Upon any default under this General Security Agreement, the Secured Party may declare any or all of the Indebtedness to be immediately due and payable and the Secured Party may proceed to realize the security hereby constituted and to enforce its rights by entry or by the appointment by instrument in writing of a receiver or receivers of the subject matter of such security or any part thereof and such receiver or receivers may be any person or persons, whether an officer or officers or employee or employees of the Secured Party or not, and the Secured Party may remove any receiver or receivers so appointed and appoint another or others in his or their stead; or by proceedings in any court of competent jurisdiction for the appointment of a receiver or receivers or for sale of the Collateral or any part thereof; or by any other action, suit, remedy or proceeding authorized or permitted hereby or by law or by equity; and may file such proofs of claim and other documents as may be necessary or advisable in order to have its claim lodged in any bankruptcy, winding-up or other judicial proceedings relative to the Debtor.

(b) Any such receiver or receivers so appointed shall have power:

(i) to take possession of the Collateral or any part thereof and to carry on the business of the Debtor;

(ii) to borrow money required for the maintenance, preservation or protection of the Collateral or any part thereof or the carrying on of the business of the Debtor;

(iii) to further charge the Collateral in priority to the security constituted by this General Security Agreement as security for money so borrowed; and

(iv) to sell, lease or otherwise dispose of the whole or any part of the Collateral on such terms and conditions and in such manner as he shall determine.

In exercising any powers any such receiver or receivers shall act as agent or agents for the Debtor and the Secured Party shall not be responsible for his or their actions.

(c) In addition, the Secured Party may enter upon and lease or sell the whole or any part or parts of the Collateral and any such sale may be made hereunder by public auction, by public tender or by private contract, with or without notice and with or without advertising and without any other formality, all of which are hereby waived by the

Debtor, and such sale shall be on such terms and conditions as to credit or otherwise and as to upset or reserve bid or price as to the Secured Party in its sole discretion may seem advantageous and such sale may take place whether or not the Secured Party has taken possession of such property and assets.

(d) No remedy for the realization of the security hereof or for the enforcement of the rights of the Secured Party shall be exclusive of or dependent on any other such remedy, but any one or more of such remedies may from time to time be exercised independently or in combination.

(e) The term "receiver" as used in this General Security Agreement includes a receiver and manager.

G. RIGHTS OF THE SECURED PARTY

12. All payments made in respect of the Indebtedness and money realized from any securities held therefor may be applied on such part or parts of the Indebtedness as the Secured Party may see fit and the Secured Party shall at all times and from time to time have the right to change any appropriation of any money received by it and to reapply the same on any other part or parts of the Indebtedness as the Secured Party may see fit, notwithstanding any previous application by whomsoever made.

13. The Secured Party, without exonerating in whole or in part the Debtor, may grant time, renewals, extensions, indulgences, releases and discharges to, may take securities from and give the same and any or all existing securities up to, may abstain from taking securities from or from perfecting securities of, may accept compositions from, and may otherwise deal with the Debtor and all other persons and securities as the Secured Party may see fit.

14. The Secured Party may assign, transfer and deliver to any transferee any of the Indebtedness or any security or any documents or instruments held by the Secured Party in respect thereof provided that no such assignment, transfer or delivery shall release the Debtor from any of the Indebtedness; and thereafter the Secured Party shall be fully discharged from all responsibility with respect to the Indebtedness and security, documents and instruments so assigned, transferred or delivered. Such transferee shall be vested with all powers and rights of the Secured Party under such security, documents or instruments but the Secured Party shall retain all rights and powers with respect to any such security, documents or instruments not so assigned, transferred or delivered. The Debtor shall not assign any of its rights or obligations hereunder without the prior written consent of the Secured Party.

H. MISCELLANEOUS

15. This General Security Agreement is in addition to, not in substitution for and shall not be merged in any other agreement, security, document or instrument now or hereafter held by the Secured Party or existing at law or in equity or by statute.

16. Nothing herein shall obligate the Secured Party to make any advance or loan or further advance or loan or to renew any note or extend any time for payment of any indebtedness of the Debtor to the Secured Party.

17. This General Security Agreement shall be binding upon the Debtor and its heirs, legatees, trustees, executors, administrators, successors and assigns including any successor by reason of amalgamation of or any other change in the Debtor and shall enure to the benefit of the Secured Party and its successors and assigns.

18. In construing this General Security Agreement, capitalized terms not otherwise defined herein shall have the same meaning as defined in the PPSA (as hereinafter defined), unless the context otherwise requires. Words importing gender shall include all genders.

19. If one or more of the provisions contained herein shall be invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

20. Where any provision or remedy contained or referred to in this General Security Agreement is prohibited, modified or altered by the laws of any province or territory of Canada which governs that aspect of this General Security Agreement and the provision or remedies may be waived or excluded by the Debtor in whole or in part, the Debtor hereby waives and excludes such provision to the fullest extent permissible by law.

21. The headings in this General Security Agreement are included herein for convenience of reference only, and shall not constitute a part of this General Security Agreement for any other purpose.

22. Any notice or statement referred to herein may be delivered, or providing that postal service throughout Canada is fully operative, may be mailed by ordinary prepaid mail to the Debtor at his last address known to the Secured Party and the Debtor shall be deemed to have received such notice or statement on the day of delivery, if delivered, and three business days after mailing, if mailed.

23. This General Security Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario as the same may be in effect from time to time including, where applicable, the Personal Property Security Act (Ontario), as amended or substituted (the "PPSA"). For the purpose of legal proceedings this General Security Agreement shall be deemed to have been made in the said Province and to be performed there and the courts of that Province shall have jurisdiction over all disputes which may arise under this General Security Agreement and the Debtor hereby irrevocably and unconditionally submits to the non-exclusive jurisdiction of such courts, provided always that nothing herein contained shall prevent the Secured Party from proceeding at its election against the Debtor in the courts of any other Province, country or jurisdiction.

25. The Debtor acknowledges having received a copy of this General Security Agreement.

THIS GENERAL SECURITY AGREEMENT has been executed by the Debtor as of the 5th day of October, 2012.

BRANTFORD POWER INC.

Per: ______________________

Authorized Signing Officer

____

BRIAN D'AMBROSE
CFO

SCHEDULE "A"

LOCATIONS OF COLLATERAL

84 Market Street, 3rd Floor, Brantford, Ontario N3T 5N8 and all other locations where the Debtor undertakes its 2011 capital program.

ATTACHMENT P

REFERENCE: 8.0 Staff-30

Please refer to RTSR Workform Model.

Utility Name	Brantford Power Inc.
Assigned EB Number	
Name and Title	Heather Wyatt, Director Regulatory Affairs,
Phone Number	519-751-3522 ext. 3629
Email Address	hwyatt@brantford.ca
Date	
Last COS Re-based Year	**2008**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

v 3.0

RTSR Workform for Electricity Distributors (2013 Filers)

Board Secretary

ely for the purpose of filing your COS/IRM application. You may use and copy this model
isting you in that regard. Except as indicated above, any copying, reproduction,
e or dissemination of this model without the express written consent of the Ontario
sing or assisting you in preparing the application or reviewing your draft rate order, you

applications, the onus remains on the applicant to ensure the accuracy of the data and

Algoma Power Inc.
Atikokan Hydro Inc.
Attawapiskat Power Corporation
Bluewater Power Distribution Corp.
Brant County Power
Brantford Power Inc.
Burlington Hydro Inc.
Cambridge and North Dumfries Hydro
Canadian Niagara Power Inc. – Eastern Ontario Power/Fort Erie/Port Colborne
Centre Wellington Hydro Ltd.
Chapleau Public Utilities Corporation
COLLUS Power Corp.
Cooperative Hydro Embrun Inc.
E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.
Entegrus Powerlines Inc.
ENWIN Utilities Ltd.
Erie Thames Powerlines Corp.
Espanola Regional Hydro Distribution Corporation
Essex Powerlines Corporation
Festival Hydro Inc.
Fort Albany Power Corporation
Fort Frances Power Corporation
Greater Sudbury Hydro Inc.
Grimsby Power Inc.
Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.
Hearst Power Distribution Co. Ltd.

Horizon Utilities Corporation
Hydro 2000 Inc.
Hydro Hawkesbury Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc.
Hydro One Remote Communities Inc.
Hydro Ottawa Limited
Innisfil Hydro Dist. Systems Limited
Kashechewan Power Corporation
Kenora Hydro Electric Corporation Ltd.
Kingston Hydro Corporation
Kitchener-Wilmot Hydro Inc.
Lakefront Utilities Inc.

Lakeland Power Distribution Ltd.
London Hydro Inc.
Midland Power Utility Corporation
Milton Hydro Distribution Inc.
Newmarket – Tay Power Distribution Ltd.
Niagara Peninsula Energy Inc.
Niagara-on-the-Lake Hydro Inc.
Norfolk Power Distribution Ltd.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Oakville Hydro Distribution Inc.
Orangeville Hydro Limited
Orillia Power Distribution Corp.
Oshawa PUC Networks Inc.
Ottawa River Power Corporation
Parry Sound Power Corporation
Peterborough Distribution Inc.
PowerStream Inc.
PUC Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.
St. Thomas Energy Inc.
Sioux Lookout Hydro Inc.
Thunder Bay Hydro Electricity Distribution
Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.
Wasaga Distribution Inc.
Waterloo North Hydro Inc.
Welland Hydro Electric System Corp.
Wellington North Power Inc.
West Coast Huron Energy Inc.
Westario Power Inc.
Whitby Hydro Electric Corporation
Woodstock Hydro Services Inc.

RTSR Wo
Electricity
(201

sale

esale

Current WS

Current WS

o Forecast WS

Forecast WS

S Rates

1. Select the appropriate rate classes that appear on your most recent Board-Approved
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and

Rate Class
Residential
General Service Less Than 50 kW
General Service 50 to 4,999 kW
Unmetered Scattered Load
Sentinel Lighting
Street Lighting
Embedded Distributor
Standby Power – INTERIM APPROVAL
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
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Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class

Workform for
city Distributors
013 Filers)

Tariff of Rates and Charges.
Charges

Unit	RTSR-Network	RTSR-Connection
kWh	$ 0.0080	$ 0.0055
kWh	$ 0.0072	$ 0.0048
kW	$ 2.4601	$ 1.6398
kWh	$ 0.0072	$ 0.0048
kW	$ 2.2973	$ 1.5315
kW	$ 2.2708	$ 1.5138
kW	$ 2.4601	$ 1.6398
kW		

In the green shaded cells, enter the most recent reported RRR billing deter
non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh
Residential	kWh	291,380,972
General Service Less Than 50 kW	kWh	99,001,655
General Service 50 to 4,999 kW	kW	430,250,985
Unmetered Scattered Load	kWh	1,556,530
Sentinel Lighting	kW	475,427
Street Lighting	kW	7,330,830
Embedded Distributor	kW	
Standby Power – INTERIM APPROVAL	kW	

RTSR Workform for
ectricity Distributors
(2013 Filers)

rminants. Please ensure that billing determinants are

Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
	1.0420		303,618,973	-
	1.0420		103,159,725	-
1,156,162		**51.01%**	430,250,985	1,156,162
	1.0420		1,621,904	-
1,423		**45.78%**	475,427	1,423
22,428		**44.80%**	7,330,830	22,428
156,840		**0.00%**	-	156,840
			-	-

Uniform Transmission Rates	Unit
Rate Description	
Network Service Rate	kW
Line Connection Service Rate	kW
Transformation Connection Service Rate	kW

Hydro One Sub-Transmission Rates	Unit
Rate Description	
Network Service Rate	kW
Line Connection Service Rate	kW
Transformation Connection Service Rate	kW
Both Line and Transformation Connection Service Rate	kW

Hydro One Sub-Transmission Rate Rider 6A	Unit

Rate Description

RSVA Transmission network – 4714 – which affects 1584	kW
RSVA Transmission connection – 4716 – which affects 1586	kW
RSVA LV – 4750 – which affects 1550	kW
RARA 1 – 2252 – which affects 1590	kW
Hydro One Sub-Transmission Rate Rider 6A	kW

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y Distributors
3 Filers)

Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate	Rate	Rate
$ 3.22	$ 3.57	$ 3.63
$ 0.79	$ 0.80	$ 0.75
$ 1.77	$ 1.86	$ 1.85

Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate	Rate	Rate
$ 2.65	$ 2.65	$ 3.18
$ 0.64	$ 0.64	$ 0.70
$ 1.50	$ 1.50	$ 1.63
$ 2.14	$ 2.14	$ 2.33

Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013

Rate	Rate	Rate
$ 0.0470	$ -	$ -
-$ 0.0250	$ -	$ -
$ 0.0580	$ -	$ -
-$ 0.0750	$ -	$ -
$ 0.0050	$ -	$ -

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	158,056	$3.22	$ 508,940	160,986	$0.79	$ 127,108	135,661	$1.77	$ 240,120	$ 367,228
February	154,508	$3.22	$ 497,516	161,229	$0.79	$ 127,371	105,510	$1.77	$ 186,753	$ 314,124
March	145,699	$3.22	$ 469,009	147,886	$0.79	$ 116,830	96,528	$1.77	$ 170,855	$ 287,685
April	131,837	$3.22	$ 424,515	140,039	$0.79	$ 110,631	93,430	$1.77	$ 165,371	$ 276,002
May	170,516	$3.22	$ 549,062	177,713	$0.79	$ 140,393	127,187	$1.77	$ 225,121	$ 365,514
June	183,492	$3.22	$ 590,844	185,036	$0.79	$ 146,178	142,175	$1.77	$ 251,650	$ 397,828
July	202,480	$3.22	$ 651,986	203,121	$0.79	$ 160,466	179,370	$1.77	$ 317,485	$ 477,950
August	173,113	$3.22	$ 557,424	176,351	$0.79	$ 139,317	155,086	$1.77	$ 274,502	$ 413,820
September	174,800	$3.22	$ 562,856	177,698	$0.79	$ 140,381	156,209	$1.77	$ 276,490	$ 416,871
October	131,873	$3.22	$ 424,631	132,554	$0.79	$ 104,718	116,370	$1.77	$ 205,975	$ 310,693
November	141,505	$3.22	$ 455,646	146,561	$0.79	$ 115,783	129,940	$1.77	$ 229,994	$ 345,777
December	143,725	$3.22	$ 462,795	148,916	$0.79	$ 117,644	130,210	$1.77	$ 230,472	$ 348,115
Total	1,911,604	$ 3.22	$ 6,155,223	1,958,090	$ 0.79	$ 1,546,820	1,567,676	$ 1.77	$ 2,774,787	$ 4,321,607

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	158,056	$3.22	$ 508,940	160,986	$0.79	$ 127,108	135,661	$1.77	$ 240,120	$ 367,228
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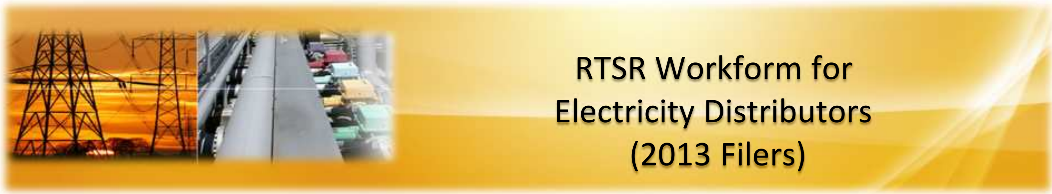
December	143,725	$3.22	$ 462,795	148,916	$0.79	$ 117,644	130,210	$1.77	$ 230,472	$ 348,115
Total	1,911,604	$ 3.22	$ 6,155,223	1,958,090	$ 0.79	$ 1,546,820	1,567,676	$ 1.77	$ 2,774,787	$ 4,321,607



The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	158,056	$ 3.5700	$ 564,260	160,986	$ 0.8000	$ 128,789	135,661	$ 1.8600	$ 252,329	$ 381,118
February	154,508	$ 3.5700	$ 551,594	161,229	$ 0.8000	$ 128,983	105,510	$ 1.8600	$ 196,249	$ 325,232
March	145,699	$ 3.5700	$ 520,145	147,886	$ 0.8000	$ 118,309	96,528	$ 1.8600	$ 179,542	$ 297,851
April	131,837	$ 3.5700	$ 470,658	140,039	$ 0.8000	$ 112,031	93,430	$ 1.8600	$ 173,780	$ 285,811
May	170,516	$ 3.5700	$ 608,742	177,713	$ 0.8000	$ 142,170	127,187	$ 1.8600	$ 236,568	$ 378,738
June	183,492	$ 3.5700	$ 655,066	185,036	$ 0.8000	$ 148,029	142,175	$ 1.8600	$ 264,446	$ 412,474
July	202,480	$ 3.5700	$ 722,854	203,121	$ 0.8000	$ 162,497	179,370	$ 1.8600	$ 333,628	$ 496,125
August	173,113	$ 3.5700	$ 618,013	176,351	$ 0.8000	$ 141,081	155,086	$ 1.8600	$ 288,460	$ 429,541
September	174,800	$ 3.5700	$ 624,036	177,698	$ 0.8000	$ 142,158	156,209	$ 1.8600	$ 290,549	$ 432,707
October	131,873	$ 3.5700	$ 470,787	132,554	$ 0.8000	$ 106,043	116,370	$ 1.8600	$ 216,448	$ 322,491
November	141,505	$ 3.5700	$ 505,173	146,561	$ 0.8000	$ 117,249	129,940	$ 1.8600	$ 241,688	$ 358,937
December	143,725	$ 3.5700	$ 513,098	148,916	$ 0.8000	$ 119,133	130,210	$ 1.8600	$ 242,191	$ 361,323
Total	1,911,604	$ 3.57	$ 6,824,426	1,958,090	$ 0.80	$ 1,566,472	1,567,676	$ 1.86	$ 2,915,877	$ 4,482,349

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
February	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
March	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
April	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
May	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
June	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
July	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
August	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
September	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
October	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
November	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
December	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	158,056	$ 3.57	$ 564,260	160,986	$ 0.80	$ 128,789	135,661	$ 1.86	$ 252,329	$ 381,118
February	154,508	$ 3.57	$ 551,594	161,229	$ 0.80	$ 128,983	105,510	$ 1.86	$ 196,249	$ 325,232
March	145,699	$ 3.57	$ 520,145	147,886	$ 0.80	$ 118,309	96,528	$ 1.86	$ 179,542	$ 297,851
April	131,837	$ 3.57	$ 470,658	140,039	$ 0.80	$ 112,031	93,430	$ 1.86	$ 173,780	$ 285,811
May	170,516	$ 3.57	$ 608,742	177,713	$ 0.80	$ 142,170	127,187	$ 1.86	$ 236,568	$ 378,738
June	183,492	$ 3.57	$ 655,066	185,036	$ 0.80	$ 148,029	142,175	$ 1.86	$ 264,446	$ 412,474
July	202,480	$ 3.57	$ 722,854	203,121	$ 0.80	$ 162,497	179,370	$ 1.86	$ 333,628	$ 496,125
August	173,113	$ 3.57	$ 618,013	176,351	$ 0.80	$ 141,081	155,086	$ 1.86	$ 288,460	$ 429,541
September	174,800	$ 3.57	$ 624,036	177,698	$ 0.80	$ 142,158	156,209	$ 1.86	$ 290,549	$ 432,707
October	131,873	$ 3.57	$ 470,787	132,554	$ 0.80	$ 106,043	116,370	$ 1.86	$ 216,448	$ 322,491
November	141,505	$ 3.57	$ 505,173	146,561	$ 0.80	$ 117,249	129,940	$ 1.86	$ 241,688	$ 358,937
December	143,725	$ 3.57	$ 513,098	148,916	$ 0.80	$ 119,133	130,210	$ 1.86	$ 242,191	$ 361,323
Total	1,911,604	$ 3.57	$ 6,824,426	1,958,090	$ 0.80	$ 1,566,472	1,567,676	$ 1.86	$ 2,915,877	$ 4,482,349

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	158,056	$ 3.6300	$ 573,743	160,986	$ 0.7500	$ 120,740	135,661	$ 1.8500	$ 250,973	$ 371,712
February	154,508	$ 3.6300	$ 560,864	161,229	$ 0.7500	$ 120,922	105,510	$ 1.8500	$ 195,194	$ 316,115
March	145,699	$ 3.6300	$ 528,887	147,886	$ 0.7500	$ 110,915	96,528	$ 1.8500	$ 178,577	$ 289,491
April	131,837	$ 3.6300	$ 478,568	140,039	$ 0.7500	$ 105,029	93,430	$ 1.8500	$ 172,846	$ 277,875
May	170,516	$ 3.6300	$ 618,973	177,713	$ 0.7500	$ 133,285	127,187	$ 1.8500	$ 235,296	$ 368,581
June	183,492	$ 3.6300	$ 666,076	185,036	$ 0.7500	$ 138,777	142,175	$ 1.8500	$ 263,024	$ 401,801
July	202,480	$ 3.6300	$ 735,002	203,121	$ 0.7500	$ 152,341	179,370	$ 1.8500	$ 331,835	$ 484,175
August	173,113	$ 3.6300	$ 628,400	176,351	$ 0.7500	$ 132,263	155,086	$ 1.8500	$ 286,909	$ 419,172
September	174,800	$ 3.6300	$ 634,524	177,698	$ 0.7500	$ 133,274	156,209	$ 1.8500	$ 288,987	$ 422,260
October	131,873	$ 3.6300	$ 478,699	132,554	$ 0.7500	$ 99,416	116,370	$ 1.8500	$ 215,285	$ 314,700
November	141,505	$ 3.6300	$ 513,663	146,561	$ 0.7500	$ 109,921	129,940	$ 1.8500	$ 240,389	$ 350,310
December	143,725	$ 3.6300	$ 521,722	148,916	$ 0.7500	$ 111,687	130,210	$ 1.8500	$ 240,889	$ 352,576
Total	1,911,604	$ 3.63	$ 6,939,123	1,958,090	$ 0.75	$ 1,468,568	1,567,676	$ 1.85	$ 2,900,201	$ 4,368,768

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
February	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
March	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
April	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
May	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
June	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
July	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
August	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
September	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
October	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
November	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
December	-	$ 3.1800	$ -	-	$ 0.7000	$ -	-	$ 1.6300	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	158,056	$ 3.63	$ 573,743	160,986	$ 0.75	$ 120,740	135,661	$ 1.85	$ 250,973	$ 371,712
February	154,508	$ 3.63	$ 560,864	161,229	$ 0.75	$ 120,922	105,510	$ 1.85	$ 195,194	$ 316,115
March	145,699	$ 3.63	$ 528,887	147,886	$ 0.75	$ 110,915	96,528	$ 1.85	$ 178,577	$ 289,491
April	131,837	$ 3.63	$ 478,568	140,039	$ 0.75	$ 105,029	93,430	$ 1.85	$ 172,846	$ 277,875
May	170,516	$ 3.63	$ 618,973	177,713	$ 0.75	$ 133,285	127,187	$ 1.85	$ 235,296	$ 368,581
June	183,492	$ 3.63	$ 666,076	185,036	$ 0.75	$ 138,777	142,175	$ 1.85	$ 263,024	$ 401,801
July	202,480	$ 3.63	$ 735,002	203,121	$ 0.75	$ 152,341	179,370	$ 1.85	$ 331,835	$ 484,175
August	173,113	$ 3.63	$ 628,400	176,351	$ 0.75	$ 132,263	155,086	$ 1.85	$ 286,909	$ 419,172
September	174,800	$ 3.63	$ 634,524	177,698	$ 0.75	$ 133,274	156,209	$ 1.85	$ 288,987	$ 422,260
October	131,873	$ 3.63	$ 478,699	132,554	$ 0.75	$ 99,416	116,370	$ 1.85	$ 215,285	$ 314,700
November	141,505	$ 3.63	$ 513,663	146,561	$ 0.75	$ 109,921	129,940	$ 1.85	$ 240,389	$ 350,310
December	143,725	$ 3.63	$ 521,722	148,916	$ 0.75	$ 111,687	130,210	$ 1.85	$ 240,889	$ 352,576
Total	1,911,604	$ 3.63	$ 6,939,123	1,958,090	$ 0.75	$ 1,468,568	1,567,676	$ 1.85	$ 2,900,201	$ 4,368,768

The purpose of this sheet is to re-align the current RTS Network Rates to rec

Rate Class	Unit	Current RTSR-Network	
Residential	kWh	$	0.0080
General Service Less Than 50 kW	kWh	$	0.0072
General Service 50 to 4,999 kW	kW	$	2.4601
Unmetered Scattered Load	kWh	$	0.0072
Sentinel Lighting	kW	$	2.2973
Street Lighting	kW	$	2.2708
Embedded Distributor	kW	$	2.4601
Standby Power – INTERIM APPROVAL	kW	$	-

:SR Workform for
:tricity Distributors
(2013 Filers)

:over current wholesale network costs.

Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing
303,618,973	-	$ 2,428,952	37.6%	$ 2,562,923
103,159,725	-	$ 742,750	11.5%	$ 783,717
430,250,985	1,156,162	$ 2,844,274	44.0%	$ 3,001,152
1,621,904	-	$ 11,678	0.2%	$ 12,322
475,427	1,423	$ 3,270	0.1%	$ 3,450
7,330,830	22,428	$ 50,930	0.8%	$ 53,739
-	156,840	$ 385,842	6.0%	$ 407,124
-	-	$ -	0.0%	$ -
		$ 6,467,695		

Proposed RTSR Network
$ 0.0084
$ 0.0076
$ 2.5958
$ 0.0076
$ 2.4240
$ 2.3960
$ 2.5958
$ -

The purpose of this sheet is to re-align the current RTS Connection Rates to

Rate Class	Unit	Current RTSR-Connection	
Residential	kWh	$	0.0055
General Service Less Than 50 kW	kWh	$	0.0048
General Service 50 to 4,999 kW	kW	$	1.6398
Unmetered Scattered Load	kWh	$	0.0048
Sentinel Lighting	kW	$	1.5315
Street Lighting	kW	$	1.5138
Embedded Distributor	kW	$	1.6398
Standby Power – INTERIM APPROVAL	kW	$	-

'SR Workform for
:tricity Distributors
(2013 Filers)

recover current wholesale connection costs.

Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing
303,618,973	-	$ 1,669,904	38.3%	$ 1,715,959
103,159,725	-	$ 495,167	11.4%	$ 508,823
430,250,985	1,156,162	$ 1,895,874	43.5%	$ 1,948,161
1,621,904	-	$ 7,785	0.2%	$ 8,000
475,427	1,423	$ 2,180	0.0%	$ 2,240
7,330,830	22,428	$ 33,952	0.8%	$ 34,888
-	156,840	$ 257,186	5.9%	$ 264,279
-	-	$ -	0.0%	$ -
		$ 4,362,048		

Proposed RTSR Connection	
$	0.0057
$	0.0049
$	1.6850
$	0.0049
$	1.5737
$	1.5555
$	1.6850
$	-

The purpose of this sheet is to update the re-align RTS Network Rates to rec

Rate Class	Unit	Adjusted RTSR-Network	
Residential	kWh	$	0.0084
General Service Less Than 50 kW	kWh	$	0.0076
General Service 50 to 4,999 kW	kW	$	2.5958
Unmetered Scattered Load	kWh	$	0.0076
Sentinel Lighting	kW	$	2.4240
Street Lighting	kW	$	2.3960
Embedded Distributor	kW	$	2.5958
Standby Power – INTERIM APPROVAL	kW	$	-

TSR Workform for
ctricity Distributors
(2013 Filers)

over forecast wholesale network costs.

Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing
303,618,973	-	$ 2,562,923	37.6%	$ 2,605,997
103,159,725	-	$ 783,717	11.5%	$ 796,889
430,250,985	1,156,162	$ 3,001,152	44.0%	$ 3,051,592
1,621,904	-	$ 12,322	0.2%	$ 12,529
475,427	1,423	$ 3,450	0.1%	$ 3,508
7,330,830	22,428	$ 53,739	0.8%	$ 54,642
-	156,840	$ 407,124	6.0%	$ 413,966
-	-	$ -	0.0%	$ -
		$ 6,824,426		

Proposed RTSR Network
$ 0.0086
$ 0.0077
$ 2.6394
$ 0.0077
$ 2.4647
$ 2.4363
$ 2.6394
$ -

RT
Elec

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forec

Rate Class	Unit	Adjusted RTSR-Connection	
Residential	kWh	$	0.0057
General Service Less Than 50 kW	kWh	$	0.0049
General Service 50 to 4,999 kW	kW	$	1.6850
Unmetered Scattered Load	kWh	$	0.0049
Sentinel Lighting	kW	$	1.5737
Street Lighting	kW	$	1.5555
Embedded Distributor	kW	$	1.6850
Standby Power – INTERIM APPROVAL	kW	$	-

'SR Workform for
;tricity Distributors
(2013 Filers)

ast wholesale connection costs.

Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing
303,618,973	-	$ 1,715,959	38.3%	$ 1,672,477
103,159,725	-	$ 508,823	11.4%	$ 495,929
430,250,985	1,156,162	$ 1,948,161	43.5%	$ 1,898,795
1,621,904	-	$ 8,000	0.2%	$ 7,797
475,427	1,423	$ 2,240	0.0%	$ 2,183
7,330,830	22,428	$ 34,888	0.8%	$ 34,004
-	156,840	$ 264,279	5.9%	$ 257,582
-	-	$ -	0.0%	$ -
		$ 4,482,349		

Proposed RTSR Connection
$ 0.0055
$ 0.0048
$ 1.6423
$ 0.0048
$ 1.5339
$ 1.5161
$ 1.6423
$ -

RTSR Workform for Electricity Distributors (2013 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0086	$ 0.0055
General Service Less Than 50 kW	kWh	$ 0.0077	$ 0.0048
General Service 50 to 4,999 kW	kW	$ 2.6394	$ 1.6423
Unmetered Scattered Load	kWh	$ 0.0077	$ 0.0048
Sentinel Lighting	kW	$ 2.4647	$ 1.5339
Street Lighting	kW	$ 2.4363	$ 1.5161
Embedded Distributor	kW	$ 2.6394	$ 1.6423
Standby Power – INTERIM APPROVAL	kW	$ -	$ -

ATTACHMENT Q

REFERENCE: 9.0 Staff-35

Please refer to the 2013 Revised Smart Meter Model.

Utility Name	Brantford Power Inc.
Assigned EB Number	EB-2012-0109
Name and Title	Heather Wyatt, Director of Regulatory Affai
Phone Number	519-751-3522 Ext 3269
Email Address	hwyatt@branford.ca
Date	22-Oct-13
Last COS Re-based Year	**2008**

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 appl results. The use of any models and spreadsheets does not automatically imply Board appro Board-issued Excel models and spreadsheets are offered to assist parties in providing the ne remains on the applicant to ensure the accuracy of the data and the results.

Smart Meter Model for Electricity Distributors (2013 Filers)

Version 3.00

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for the purpose of filing your appliation. You may use and copy this model for that purpose,
ard. Except as indicated aboveany copying, reproduction, publication, sale, adaptation,
without the express written conset of the Ontario Energy Board is prohibited. If you
ipplication or reviewing your drft rate order, you must ensure that the person understands

plications, the onus remains on th applicant to ensure the accuracy of the data and the
roval. The onus is on the distributc to prepare, document and support its application.
necessary information so as to facilate an expeditious review of an application. The onus

Algoma Power Inc.
Atikokan Hydro Inc.
Attawapiskat Power Corporation
Bluewater Power Distribution Corp.
Brant County Power
Brantford Power Inc.
Burlington Hydro Inc.
Cambridge and North Dumfries Hydro
Canadian Niagara Power Inc. – Eastern Ontario Power/Fort Erie/Port Colborne
Centre Wellington Hydro Ltd.
Chapleau Public Utilities Corporation
COLLUS Power Corp.
Cooperative Hydro Embrun Inc.
E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.
Entegrus Powerlines Inc.
ENWIN Utilities Ltd.
Erie Thames Powerlines Corp.
Espanola Regional Hydro Distribution Corporation
Essex Powerlines Corporation
Festival Hydro Inc.
Fort Albany Power Corporation
Fort Frances Power Corporation
Greater Sudbury Hydro Inc.
Grimsby Power Inc.
Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.
Hearst Power Distribution Co. Ltd.

Horizon Utilities Corporation
Hydro 2000 Inc.
Hydro Hawkesbury Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc.
Hydro One Remote Communities Inc.
Hydro Ottawa Limited
Innisfil Hydro Dist. Systems Limited
Kashechewan Power Corporation
Kenora Hydro Electric Corporation Ltd.
Kingston Hydro Corporation
Kitchener-Wilmot Hydro Inc.
Lakefront Utilities Inc.

Lakeland Power Distribution Ltd.
London Hydro Inc.
Midland Power Utility Corporation
Milton Hydro Distribution Inc.
Newmarket – Tay Power Distribution Ltd.
Niagara Peninsula Energy Inc.
Niagara-on-the-Lake Hydro Inc.
Norfolk Power Distribution Ltd.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Oakville Hydro Distribution Inc.
Orangeville Hydro Limited
Orillia Power Distribution Corp.
Oshawa PUC Networks Inc.
Ottawa River Power Corporation
Parry Sound Power Corporation
Peterborough Distribution Inc.
PowerStream Inc.
PUC Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.
St. Thomas Energy Inc.
Sioux Lookout Hydro Inc.
Thunder Bay Hydro Electricity Distribution
Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.
Wasaga Distribution Inc.
Waterloo North Hydro Inc.
Welland Hydro Electric System Corp.
Wellington North Power Inc.
West Coast Huron Energy Inc.
Westario Power Inc.
Whitby Hydro Electric Corporation
Woodstock Hydro Services Inc.

Smart Meter Model for Electricity Distributors (2013 Filers)

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

		2006	2007	2008	2009	2010	2011	2012	2013	Total
Smart Meter Capital Cost and Operational Expense Data		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan										
Actual/Planned number of Smart Meters installed during the Calendar Year										
Residential				293	6,331	27,735	458	110		34927
General Service < 50 kW					204	1,057	1,380	107		2748
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		0	0	293	6535	28792	1838	217	0	37675
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		0.00%	0.00%	0.78%	18.12%	94.55%	99.42%	100.00%	0.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed										0
Other (please identify)										0
Total Number of Smart Meters installed or planned to be installed		0	0	293	6535	28792	1838	217	0	37675
1 Capital Costs										
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	**Asset Type** Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter			14,945	1,375,700	2,452,471	34,884	73,273		$ 3,951,273
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				13,969	342,583	2,565			$ 359,118
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Hardware				39,852	2,086				$ 41,939
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Software									$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ 14,945	$ 1,429,521	$ 2,797,141	$ 37,449	$ 73,273	$ -	$ 4,352,329
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Smart Meter				184,684					$ 184,684
1.2.2 Repeaters *(may include radio licence, etc.)*										$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Smart Meter				11,113	77,304	25,829	888		$ 115,134
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 195,798	$ 77,304	$ 25,829	$ 888	$ -	$ 299,818

	Asset Type									
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware										$ -
1.3.2 Computer Software	Computer Software				106	78	1,780			$ 1,963
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*										$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ 106	$ 78	$ 1,780	$ -	$ -	$ 1,963
	Asset Type									
1.4 WIDE AREA NETWORK (WAN)		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees										$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Asset Type									
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*										$ -
1.5.2 AMI Interface to CIS										$ -
1.5.3 Professional Fees	Smart Meter		12,763	19,371	22,381	25,177	9,542	12,367		$ 101,601
1.5.4 Integration	Smart Meter				7,632	47,057	60,811			$ 115,499
1.5.5 Program Management	Smart Meter	12,808			120,065	139,096	230,558			$ 502,527
1.5.6 Other AMI Capital										$ -
Total Other AMI Capital Costs Related to Minimum Functionality		$ 12,808	$ 12,763	$ 19,371	$ 150,078	$ 211,330	$ 300,911	$ 12,367	$ -	$ 719,627
Total Capital Costs Related to Minimum Functionality		$ 12,808	$ 12,763	$ 34,316	$ 1,775,503	$ 3,085,852	$ 365,968	$ 86,528	$ -	$ 5,373,737
	Asset Type									
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06										$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service										$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.										$ -
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter Capital Costs		$ 12,808	$ 12,763	$ 34,316	$ 1,775,503	$ 3,085,852	$ 365,968	$ 86,528	$ -	$ 5,373,737

2 OM&A Expenses

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1.1 Maintenance *(may include meter reverification costs, etc.)*				2,468	22,585	695			$ 25,748
2.1.2 Other *(please specify)*									$ -
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ 2,468	$ 22,585	$ 695	$ -	$ -	$ 25,748
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)									
2.2.1 Maintenance						26,601	139,030	187,477	$ 353,107
2.2.2 Other *(please specify)*									$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ 26,601	$ 139,030	$ 187,477	$ 353,107
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)									
2.3.1 Hardware Maintenance *(may include server support, etc.)*									$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*									$ -
2.3.2 Other *(please specify)*									$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)									
2.4.1 WAN Maintenance									$ -
2.4.2 Other *(please specify)*									$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY									
2.5.1 Business Process Redesign									$ -
2.5.2 Customer Communication (may include project communication, etc.)									$ -
2.5.3 Program Management				2,674		23,920	54,227		$ 80,821
2.5.4 Change Management (may include training, etc.)									$ -
2.5.5 Administration Costs									$ -
2.5.6 Other AMI Expenses *(please specify)*									$ -
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ -	$ -	$ 2,674	$ -	$ 23,920	$ 54,227	$ -	$ 80,821
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ 5,142	$ 22,585	$ 51,215	$ 193,256	$ 187,477	$ 459,676
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual			
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06									$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service									$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.									$ -
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ 5,142	$ 22,585	$ 51,215	$ 193,256	$ 187,477	$ 459,676

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**									
3.1.1	Smart Meter	$ 12,808	$ 12,763	$ 34,316	$ 1,735,545	$ 3,083,688	$ 364,189	$ 86,528	$ -	$ 5,329,836
3.1.2	Computer Hardware	$ -	$ -	$ -	$ 39,852	$ 2,086	$ -	$ -	$ -	$ 41,939
3.1.3	Computer Software	$ -	$ -	$ -	$ 106	$ 78	$ 1,780	$ -	$ -	$ 1,963
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ 12,808**	**$ 12,763**	**$ 34,316**	**$ 1,775,503**	**$ 3,085,852**	**$ 365,968**	**$ 86,528**	**$ -**	**$ 5,373,737**
3.2	**OM&A Costs**									
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 5,142**	**$ 22,585**	**$ 51,215**	**$ 193,256**	**$ 187,477**	**$ 459,676**

Smart Meter Model for Electricity Distributors (2013 Filers)

	2006	2007	2008	2009	2010	2011	2012	2013
Cost of Capital								
Capital Structure[1]								
Deemed Short-term Debt Capitalization			4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	49.3%	52.7%	56.0%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%	40.0%
Preferred Shares	0.0%							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters								
Deemed Short-term Debt Rate			4.47%	1.33%	2.07%	2.46%	2.46%	2.08%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.04%	6.04%	6.10%	7.62%	5.87%	5.32%	5.32%	4.03%
Target Return on Equity (ROE)	8.6%	8.57%	8.57%	8.01%	9.85%	9.58%	9.58%	8.93%
Return on Preferred Shares								
WACC	7.31%	7.31%	7.19%	7.54%	7.31%	6.91%	6.91%	5.91%
Working Capital Allowance								
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	13.0%
(% of the sum of Cost of Power + controllable expenses)								
Taxes/PILs								
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.50%	26.50%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%	0.00%

Depreciation Rates
(expressed as expected useful life in years)

Smart Meters - years	15	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

CCA Rates

Smart Meters - CCA Class	47	47	47	47	47	47	47	47
Smart Meters - CCA Rate	8%	8%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	10	10	10	10	10	10	10	10
Computer Equipment - CCA Rate	30%	30%	30%	30%	30%	30%	30%	30%
General Equipment - CCA Class	8	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class	52	52	52	52	52	52	52	52
Applications Software - CCA Rate	100%	100%	100%	100%	100%	100%	100%	100%

Assumptions

[1] *Planned smart meter installations occur evenly throughout the year.*

[2] *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Smart Meter Model for Electricity Distributors (2013 Filers)

	2006	2007	2008	2009	2010	2011	2012	2013
Net Fixed Assets - Smart Meters								
Gross Book Value								
Opening Balance		$ 12,808	$ 25,571	$ 59,887	$ 1,795,432	$ 4,879,120	$ 5,243,308	$ 5,329,836
Capital Additions during year (from Smart Meter Costs)	$ 12,808	$ 12,763	$ 34,316	$ 1,735,545	$ 3,083,688	$ 364,189	$ 86,528	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ 12,808	$ 25,571	$ 59,887	$ 1,795,432	$ 4,879,120	$ 5,243,308	$ 5,329,836	$ 5,329,836
Accumulated Depreciation								
Opening Balance		-$ 427	-$ 1,706	-$ 4,555	-$ 66,399	-$ 288,884	-$ 626,298	-$ 978,736
Amortization expense during year	-$ 427	-$ 1,279	-$ 2,849	-$ 61,844	-$ 222,485	-$ 337,414	-$ 352,438	-$ 355,322
Retirements/Removals (if applicable)								
Closing Balance	-$ 427	-$ 1,706	-$ 4,555	-$ 66,399	-$ 288,884	-$ 626,298	-$ 978,736	-$ 1,334,059
Net Book Value								
Opening Balance	$ -	$ 12,381	$ 23,865	$ 55,332	$ 1,729,033	$ 4,590,236	$ 4,617,010	$ 4,351,100
Closing Balance	$ 12,381	$ 23,865	$ 55,332	$ 1,729,033	$ 4,590,236	$ 4,617,010	$ 4,351,100	$ 3,995,777
Average Net Book Value	$ 6,190	$ 18,123	$ 39,599	$ 892,183	$ 3,159,634	$ 4,603,623	$ 4,484,055	$ 4,173,438
Net Fixed Assets - Computer Hardware								
Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ 39,852	$ 41,939	$ 41,939	$ 41,939
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 39,852	$ 2,086	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ 39,852	$ 41,939	$ 41,939	$ 41,939	$ 41,939
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	-$ 3,985	-$ 12,164	-$ 20,552	-$ 28,940
Amortization expense during year	$ -	$ -	$ -	-$ 3,985	-$ 8,179	-$ 8,388	-$ 8,388	-$ 8,388
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	-$ 3,985	-$ 12,164	-$ 20,552	-$ 28,940	-$ 37,328
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ 35,867	$ 29,774	$ 21,387	$ 12,999
Closing Balance	$ -	$ -	$ -	$ 35,867	$ 29,774	$ 21,387	$ 12,999	$ 4,611
Average Net Book Value	$ -	$ -	$ -	$ 17,934	$ 32,821	$ 25,580	$ 17,193	$ 8,805

Net Fixed Assets - Computer Software (including Applications Software)

Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ 106	$ 183	$ 1,963	$ 1,963
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 106	$ 78	$ 1,780	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ 106	$ 183	$ 1,963	$ 1,963	$ 1,963
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	-$ 11	-$ 39	-$ 254	-$ 647
Amortization expense during year	$ -	$ -	$ -	-$ 11	-$ 29	-$ 215	-$ 393	-$ 393
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	-$ 11	-$ 39	-$ 254	-$ 647	-$ 1,039
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ 95	$ 144	$ 1,709	$ 1,316
Closing Balance	$ -	$ -	$ -	$ 95	$ 144	$ 1,709	$ 1,316	$ 924
Average Net Book Value	$ -	$ -	$ -	$ 48	$ 119	$ 926	$ 1,513	$ 1,120

Net Fixed Assets - Tools and Equipment

Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Smart Meter Model for Electricity Distributors (2013 Filers)

	2006	2007	2008	2009	2010	2011	2012	2013
Average Net Fixed Asset Values (from Sheet 4)								
Smart Meters	$ 6,190	$ 18,123	$ 39,599	$ 892,183	$ 3,159,634	$ 4,603,623	$ 4,484,055	$ 4,173,438
Computer Hardware	$ -	$ -	$ -	$ 17,934	$ 32,821	$ 25,580	$ 17,193	$ 8,805
Computer Software	$ -	$ -	$ -	$ 48	$ 119	$ 926	$ 1,513	$ 1,120
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ 6,190**	**$ 18,123**	**$ 39,599**	**$ 910,164**	**$ 3,192,575**	**$ 4,630,130**	**$ 4,502,760**	**$ 4,183,363**
Working Capital								
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ 5,142	$ 22,585	$ 51,215	$ 193,256	$ 187,477
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%	13%
Working Capital Allowance	$ -	$ -	$ -	$ 771	$ 3,388	$ 7,682	$ 28,988	$ 24,372
Incremental Smart Meter Rate Base	**$ 6,190**	**$ 18,123**	**$ 39,599**	**$ 910,935**	**$ 3,195,962**	**$ 4,637,812**	**$ 4,531,749**	**$ 4,207,735**
Return on Rate Base								
Capital Structure								
Deemed Short Term Debt	$ -	$ -	$ 1,584	$ 36,437	$ 127,838	$ 185,512	$ 181,270	$ 168,309
Deemed Long Term Debt	$ 3,095	$ 9,061	$ 19,522	$ 480,063	$ 1,789,739	$ 2,597,175	$ 2,537,779	$ 2,356,332
Equity	$ 3,095	$ 9,061	$ 18,493	$ 394,435	$ 1,278,385	$ 1,855,125	$ 1,812,699	$ 1,683,094
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ 6,190	$ 18,123	$ 39,599	$ 910,935	$ 3,195,962	$ 4,637,812	$ 4,531,749	$ 4,207,735
Return on								
Deemed Short Term Debt	$ -	$ -	$ 71	$ 485	$ 2,646	$ 4,564	$ 4,459	$ 3,501
Deemed Long Term Debt	$ 187	$ 547	$ 1,191	$ 36,581	$ 105,058	$ 138,170	$ 135,010	$ 94,960
Equity	$ 265	$ 777	$ 1,585	$ 31,594	$ 125,921	$ 177,721	$ 173,657	$ 150,300
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ 452	$ 1,324	$ 2,846	$ 68,660	$ 233,625	$ 320,454	$ 313,126	$ 248,761
Operating Expenses	$ -	$ -	$ -	$ 5,142	$ 22,585	$ 51,215	$ 193,256	$ 187,477
Amortization Expenses (from Sheet 4)								
Smart Meters	$ 427	$ 1,279	$ 2,849	$ 61,844	$ 222,485	$ 337,414	$ 352,438	$ 355,322
Computer Hardware	$ -	$ -	$ -	$ 3,985	$ 8,179	$ 8,388	$ 8,388	$ 8,388
Computer Software	$ -	$ -	$ -	$ 11	$ 29	$ 215	$ 393	$ 393
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ 427	$ 1,279	$ 2,849	$ 65,840	$ 230,693	$ 346,017	$ 361,218	$ 364,103
Incremental Revenue Requirement before Taxes/PILs	$ 879	$ 2,603	$ 5,695	$ 139,642	$ 486,903	$ 717,686	$ 867,601	$ 800,341
Calculation of Taxable Income								
Incremental Operating Expenses	$ -	$ -	$ -	$ 5,142	$ 22,585	$ 51,215	$ 193,256	$ 187,477
Amortization Expense	$ 427	$ 1,279	$ 2,849	$ 65,840	$ 230,693	$ 346,017	$ 361,218	$ 364,103
Interest Expense	$ 187	$ 547	$ 1,262	$ 37,065	$ 107,704	$ 142,733	$ 139,469	$ 98,461
Net Income for Taxes/PILs	$ 265	$ 777	$ 1,585	$ 31,594	$ 125,921	$ 177,721	$ 173,657	$ 150,300
Grossed-up Taxes/PILs (from Sheet 7)	$ 138.85	$ 371.29	$ 716.72	$ 12,663.88	$ 41,852.32	$ 54,360.59	$ 58,953.00	$ 61,498.15
Revenue Requirement, including Grossed-up Taxes/PILs	$ 1,018	$ 2,974	$ 6,412	$ 152,306	$ 528,755	$ 772,047	$ 926,554	$ 861,839

Smart Meter Model for Electricity Distributors (2013 Filers)

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Forecast
Opening UCC	$ -	$ 12,295.27	$ 23,564.59	$ 54,622.89	$ 1,716,375.90	$ 4,539,406.04	$ 4,525,874.56	$ 4,246,871.14
Capital Additions	$ 12,807.57	$ 12,763.48	$ 34,316.12	$ 1,735,544.62	$ 3,083,687.72	$ 364,188.55	$ 86,527.65	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ 12,807.57	$ 25,058.75	$ 57,880.71	$ 1,790,167.51	$ 4,800,063.62	$ 4,903,594.59	$ 4,612,402.21	$ 4,246,871.14
Half Year Rule (1/2 Additions - Disposals)	$ 6,403.79	$ 6,381.74	$ 17,158.06	$ 867,772.31	$ 1,541,843.86	$ 182,094.28	$ 43,263.83	$ -
Reduced UCC	$ 6,403.79	$ 18,677.01	$ 40,722.65	$ 922,395.20	$ 3,258,219.76	$ 4,721,500.31	$ 4,569,138.39	$ 4,246,871.14
CCA Rate Class	47	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%	8%
CCA	$ 512.30	$ 1,494.16	$ 3,257.81	$ 73,791.62	$ 260,657.58	$ 377,720.03	$ 365,531.07	$ 339,749.69
Closing UCC	$ 12,295.27	$ 23,564.59	$ 54,622.89	$ 1,716,375.90	$ 4,539,406.04	$ 4,525,874.56	$ 4,246,871.14	$ 3,907,121.45

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 33,964.27	$ 25,614.42	$ 19,442.91	$ 13,610.03
Capital Additions Computer Hardware	$ -	$ -	$ -	$ 39,852.41	$ 2,086.25	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ 105.56	$ 77.78	$ 1,779.78	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ 39,957.97	$ 36,128.30	$ 27,394.20	$ 19,442.91	$ 13,610.03
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 19,978.99	$ 1,082.02	$ 889.89	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ 19,978.99	$ 35,046.29	$ 26,504.31	$ 19,442.91	$ 13,610.03
CCA Rate Class	10	10	10	10	10	10	10	10
CCA Rate	30%	30%	30%	30%	30%	30%	30%	30%
CCA	$ -	$ -	$ -	$ 5,993.70	$ 10,513.89	$ 7,951.29	$ 5,832.87	$ 4,083.01
Closing UCC	$ -	$ -	$ -	$ 33,964.27	$ 25,614.42	$ 19,442.91	$ 13,610.03	$ 9,527.02

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	8	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC - Applications Software

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	52	52	52	52	52	52	52	52
CCA Rate	100%	100%	100%	100%	100%	100%	100%	100%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Smart Meter Model for Electricity Distributors (2013 Filers)

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Forecast
INCOME TAX								
Net Income	$ 265.26	$ 776.56	$ 1,584.81	$ 31,594.24	$ 125,920.91	$ 177,720.96	$ 173,656.61	$ 150,300.31
Amortization	$ 426.92	$ 1,279.29	$ 2,848.61	$ 65,839.76	$ 230,693.04	$ 346,016.63	$ 361,218.48	$ 364,102.74
CCA - Smart Meters	-$ 512.30	-$ 1,494.16	-$ 3,257.81	-$ 73,791.62	-$ 260,657.58	-$ 377,720.03	-$ 365,531.07	-$ 339,749.69
CCA - Computers	$ -	$ -	$ -	-$ 5,993.70	-$ 10,513.89	-$ 7,951.29	-$ 5,832.87	-$ 4,083.01
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ 179.87	$ 561.69	$ 1,175.61	$ 17,648.69	$ 85,442.49	$ 138,066.27	$ 163,511.15	$ 170,570.34
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.50%	26.50%
Income Taxes Payable	$ 64.97	$ 202.88	$ 393.83	$ 5,824.07	$ 26,487.17	$ 39,003.72	$ 43,330.45	$ 45,201.14
ONTARIO CAPITAL TAX								
Smart Meters	$ 12,380.65	$ 23,864.84	$ 55,332.36	$ 1,729,033.01	$ 4,590,235.69	$ 4,617,009.99	$ 4,351,099.51	$ 3,995,777.13
Computer Hardware	$ -	$ -	$ -	$ 35,867.17	$ 29,774.31	$ 21,386.58	$ 12,998.85	$ 4,611.12
Computer Software (Including Application Software)	$ -	$ -	$ -	$ 95.00	$ 143.89	$ 1,709.03	$ 1,316.40	$ 923.78
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ 12,380.65	$ 23,864.84	$ 55,332.36	$ 1,764,995.18	$ 4,620,153.89	$ 4,640,105.59	$ 4,365,414.76	$ 4,001,312.03
Less: Exemption								
Deemed Taxable Capital	$ 12,380.65	$ 23,864.84	$ 55,332.36	$ 1,764,995.18	$ 4,620,153.89	$ 4,640,105.59	$ 4,365,414.76	$ 4,001,312.03
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ 37.14	$ 53.70	$ 124.50	$ 3,971.24	$ 3,465.12	$ -	$ -	$ -
Change in Income Taxes Payable	$ 64.97	$ 202.88	$ 393.83	$ 5,824.07	$ 26,487.17	$ 39,003.72	$ 43,330.45	$ 45,201.14
Change in OCT	$ 37.14	$ 53.70	$ 124.50	$ 3,971.24	$ 3,465.12	$ -	$ -	$ -
PILs	$ 102.11	$ 256.58	$ 518.33	$ 9,795.31	$ 29,952.29	$ 39,003.72	$ 43,330.45	$ 45,201.14
Gross Up PILs								
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.50%	26.50%
Change in Income Taxes Payable	$ 101.71	$ 317.60	$ 592.22	$ 8,692.64	$ 38,387.20	$ 54,360.59	$ 58,953.00	$ 61,498.15
Change in OCT	$ 37.14	$ 53.70	$ 124.50	$ 3,971.24	$ 3,465.12	$ -	$ -	$ -
PILs	**$ 138.85**	**$ 371.29**	**$ 716.72**	**$ 12,663.88**	**$ 41,852.32**	**$ 54,360.59**	**$ 58,953.00**	**$ 61,498.15**

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
2006 Q1			Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
2007 Q1	4.59%	4.72%	May-06	2006	Q2	$ -	$ 2,479.10	4.14%	$ -	$ 2,479.10		$ 0.30
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	$ 2,479.10	$ 15,532.19	4.14%	$ 8.55	$ 18,019.84		$ 0.30
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	$ 18,011.29	$ 12,170.75	4.59%	$ 68.89	$ 30,250.93		$ 0.30
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	$ 30,182.04	$ 10,266.90	4.59%	$ 115.45	$ 40,564.39		$ 0.30
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	$ 40,448.94	$ 9,697.03	4.59%	$ 154.72	$ 50,300.69		$ 0.30
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	$ 50,145.97	$ 10,685.26	4.59%	$ 191.81	$ 61,023.04		$ 0.30
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	$ 60,831.23	$ 9,746.74	4.59%	$ 232.68	$ 70,810.65		$ 0.30
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	$ 70,577.97	$ 9,912.36	4.59%	$ 269.96	$ 80,760.29	$ 81,532.39	$ 0.30
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	$ 80,490.33	$ 10,918.10	4.59%	$ 307.88	$ 91,716.31		$ 0.30
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	$ 91,408.43	$ 8,953.44	4.59%	$ 349.64	$ 100,711.51		$ 0.30
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	$ 100,361.87	$ 10,986.35	4.59%	$ 383.88	$ 111,732.10		$ 0.30
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	$ 111,348.22	$ 9,903.45	4.59%	$ 425.91	$ 121,677.58		$ 0.30
2010 Q1	0.55%	4.34%	May-07	2007	Q2	$ 121,251.67	$ 10,482.10	4.59%	$ 463.79	$ 132,197.56		$ 0.28
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	$ 131,733.77	$ 9,796.12	4.59%	$ 503.88	$ 142,033.77		$ 0.28
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	$ 141,529.89	$ 10,352.94	4.59%	$ 541.35	$ 152,424.18		$ 0.28
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	$ 151,882.83	$ 10,144.28	4.59%	$ 580.95	$ 162,608.06		$ 0.28
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	$ 162,027.11	$ 9,646.91	4.59%	$ 619.75	$ 172,293.77		$ 0.28
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	$ 171,674.02	$ 10,797.15	5.14%	$ 735.34	$ 183,206.51		$ 0.28
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	$ 182,471.17	$ 9,893.02	5.14%	$ 781.58	$ 193,145.77		$ 0.28
2011 Q4	1.47%	3.92%	Dec-07	2007	Q4	$ 192,364.19	$ 10,066.58	5.14%	$ 823.96	$ 203,254.73	$ 128,458.35	$ 0.28
2012 Q1	1.47%	3.92%	Jan-08	2008	Q1	$ 202,430.77	$ 10,996.93	5.14%	$ 867.08	$ 214,294.78		$ 0.28
2012 Q2	1.47%	3.51%	Feb-08	2008	Q1	$ 213,427.70	$ 9,440.32	5.14%	$ 914.18	$ 223,782.20		$ 0.28
2012 Q3	1.47%	3.51%	Mar-08	2008	Q1	$ 222,868.02	$ 10,812.98	5.14%	$ 954.62	$ 234,635.62		$ 0.28
2012 Q4	1.47%	3.23%	Apr-08	2008	Q2	$ 233,681.00	$ 10,560.35	4.08%	$ 794.52	$ 245,035.87		$ 0.28
2013 Q1	1.47%	3.23%	May-08	2008	Q2	$ 244,241.35	$ 10,322.30	4.08%	$ 830.42	$ 255,394.07		$ 0.28
2013 Q2	1.47%	3.23%	Jun-08	2008	Q2	$ 254,563.65	$ 9,941.52	4.08%	$ 865.52	$ 265,370.69		$ 0.28
2013 Q3	1.47%	3.23%	Jul-08	2008	Q3	$ 264,505.17	$ 10,357.94	3.35%	$ 738.41	$ 275,601.52		$ 0.28

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
2013 Q4	1.47%	3.23%	Aug-08	2008	Q3	$ 274,863.11	$ 10,160.07	3.35%	$ 767.33	$ 285,790.51		$ 0.28
			Sep-08	2008	Q3	$ 285,023.18	$ 10,467.03	3.35%	$ 795.69	$ 296,285.90		$ 0.28
			Oct-08	2008	Q4	$ 295,490.21	$ 10,373.81	3.35%	$ 824.91	$ 306,688.93		$ 0.28
			Nov-08	2008	Q4	$ 305,864.02	$ 9,843.21	3.35%	$ 853.87	$ 316,561.10		$ 0.28
			Dec-08	2008	Q4	$ 315,707.23	$ 10,530.57	3.35%	$ 881.35	$ 327,119.15	$ 133,894.93	$ 0.28
			Jan-09	2009	Q1	$ 326,237.80	$ 10,904.16	2.45%	$ 666.07	$ 337,808.03		$ 0.28
			Feb-09	2009	Q1	$ 337,141.96	$ 9,385.93	2.45%	$ 688.33	$ 347,216.22		$ 0.28
			Mar-09	2009	Q1	$ 346,527.89	$ 11,202.54	2.45%	$ 707.49	$ 358,437.92		$ 0.28
			Apr-09	2009	Q2	$ 357,730.43	$ 10,246.77	1.00%	$ 298.11	$ 368,275.31		$ 0.28
			May-09	2009	Q2	$ 367,977.20	$ 15,281.06	1.00%	$ 306.65	$ 383,564.91		$ 1.00
			Jun-09	2009	Q2	$ 383,258.26	$ 57,173.69	1.00%	$ 319.38	$ 440,751.33		$ 1.00
			Jul-09	2009	Q3	$ 440,431.95	$ 37,855.16	0.55%	$ 201.86	$ 478,488.97		$ 1.00
			Aug-09	2009	Q3	$ 478,287.11	$ 36,486.46	0.55%	$ 219.21	$ 514,992.78		$ 1.00
			Sep-09	2009	Q3	$ 514,773.57	$ 37,709.41	0.55%	$ 235.94	$ 552,718.92		$ 1.00
			Oct-09	2009	Q4	$ 552,482.98	$ 37,588.35	0.55%	$ 253.22	$ 590,324.55		$ 1.00
			Nov-09	2009	Q4	$ 590,071.33	$ 36,383.06	0.55%	$ 270.45	$ 626,724.84		$ 1.00
			Dec-09	2009	Q4	$ 626,454.39	$ 39,032.53	0.55%	$ 287.12	$ 665,774.04	$ 343,702.95	$ 1.00
			Jan-10	2010	Q1	$ 665,486.92	$ 36,574.16	0.55%	$ 305.01	$ 702,366.09		$ 1.00
			Feb-10	2010	Q1	$ 702,061.08	$ 34,908.86	0.55%	$ 321.78	$ 737,291.72		$ 1.00
			Mar-10	2010	Q1	$ 736,969.94	$ 39,841.63	0.55%	$ 337.78	$ 777,149.35		$ 1.00
			Apr-10	2010	Q2	$ 776,811.57	$ 35,278.56	0.55%	$ 356.04	$ 812,446.17		$ 1.00
			May-10	2010	Q2	$ 812,090.13	$ 46,643.59	0.55%	$ 372.21	$ 859,105.93		$ 2.07
			Jun-10	2010	Q2	$ 858,733.72	$ 99,949.82	0.55%	$ 393.59	$ 959,077.13		$ 2.07
			Jul-10	2010	Q3	$ 958,683.54	$ 84,419.58	0.89%	$ 711.02	$ 1,043,814.14		$ 2.07
			Aug-10	2010	Q3	$ 1,043,103.12	$ 78,607.46	0.89%	$ 773.63	$ 1,122,484.21		$ 2.07
			Sep-10	2010	Q3	$ 1,121,710.58	$ 75,347.27	0.89%	$ 831.94	$ 1,197,889.79		$ 2.07
			Oct-10	2010	Q4	$ 1,197,057.85	$ 79,094.69	1.20%	$ 1,197.06	$ 1,277,349.60		$ 2.07
			Nov-10	2010	Q4	$ 1,276,152.54	$ 78,425.16	1.20%	$ 1,276.15	$ 1,355,853.85		$ 2.07
			Dec-10	2010	Q4	$ 1,354,577.70	$ 76,510.60	1.20%	$ 1,354.58	$ 1,432,442.88	$ 773,832.17	$ 2.07
			Jan-11	2011	Q1	$ 1,431,088.30	$ 75,418.34	1.47%	$ 1,753.08	$ 1,508,259.72		$ 2.07
			Feb-11	2011	Q1	$ 1,506,506.64	$ 76,324.87	1.47%	$ 1,845.47	$ 1,584,676.98		$ 2.07
			Mar-11	2011	Q1	$ 1,582,831.51	$ 83,621.94	1.47%	$ 1,938.97	$ 1,668,392.42		$ 2.07

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
			Apr-11	2011	Q2	$ 1,666,453.45	$ 76,495.07	1.47%	$ 2,041.41	$ 1,744,989.93		$ 2.07
			May-11	2011	Q2	$ 1,742,948.52	$ 81,075.95	1.47%	$ 2,135.11	$ 1,826,159.58		$ 2.07
			Jun-11	2011	Q2	$ 1,824,024.47	$ 74,388.23	1.47%	$ 2,234.43	$ 1,900,647.13		$ 2.07
			Jul-11	2011	Q3	$ 1,898,412.70	$ 77,534.79	1.47%	$ 2,325.56	$ 1,978,273.05		$ 2.07
			Aug-11	2011	Q3	$ 1,975,947.49	$ 80,315.09	1.47%	$ 2,420.54	$ 2,058,683.12		$ 2.07
			Sep-11	2011	Q3	$ 2,056,262.58	$ 76,931.02	1.47%	$ 2,518.92	$ 2,135,712.52		$ 2.07
			Oct-11	2011	Q4	$ 2,133,193.60	$ 68,971.95	1.47%	$ 2,613.16	$ 2,204,778.71		$ 2.07
			Nov-11	2011	Q4	$ 2,202,165.55	$ 87,816.68	1.47%	$ 2,697.65	$ 2,292,679.88		$ 2.07
			Dec-11	2011	Q4	$ 2,289,982.23	$ 79,107.29	1.47%	$ 2,805.23	$ 2,371,894.75	$ 965,330.75	$ 2.07
			Jan-12	2012	Q1	$ 2,369,089.52	$ 81,775.81	1.47%	$ 2,902.13	$ 2,453,767.46		$ 2.07
			Feb-12	2012	Q1	$ 2,450,865.33	$ 73,022.81	1.47%	$ 3,002.31	$ 2,526,890.45		$ 2.07
			Mar-12	2012	Q1	$ 2,523,888.14	$ 81,380.02	1.47%	$ 3,091.76	$ 2,608,359.92		$ 2.07
			Apr-12	2012	Q2	$ 2,605,268.16	$ 78,380.11	1.47%	$ 3,191.45	$ 2,686,839.72		$ 2.07
			May-12	2012	Q2	$ 2,683,648.27	$ 20.85	1.47%	$ 3,287.47	$ 2,686,956.59		
			Jun-12	2012	Q2	$ 2,683,669.12	-$ 0.14	1.47%	$ 3,287.49	$ 2,686,956.47		
			Jul-12	2012	Q3	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Aug-12	2012	Q3	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Sep-12	2012	Q3	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Oct-12	2012	Q4	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Nov-12	2012	Q4	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Dec-12	2012	Q4	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47	$ 353,067.01	
			Jan-13	2013	Q1	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Feb-13	2013	Q1	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Mar-13	2013	Q1	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Apr-13	2013	Q2	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			May-13	2013	Q2	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Jun-13	2013	Q2	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Jul-13	2013	Q3	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Aug-13	2013	Q3	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Sep-13	2013	Q3	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Oct-13	2013	Q4	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		
			Nov-13	2013	Q4	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47		

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder
			Dec-13	*2013*	*Q4*	$ 2,683,668.98		1.47%	$ 3,287.49	$ 2,686,956.47	$ 39,449.88	
			Total Funding Adder Revenues Collected				**$ 2,683,668.98**		**$ 96,149.57**	**$ 2,779,818.55**	**$ 2,779,818.55**	

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	3.92%
2012 Q1	1.47%	3.92%
2012 Q2	1.47%	3.51%
2012 Q3	1.47%	3.51%
2012 Q4	1.47%	3.23%
2013 Q1	1.47%	3.23%
2013 Q2	1.47%	3.23%
2013 Q3	1.47%	3.23%
2013 Q4	1.47%	3.23%

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Date	*Year*	*Quarter*	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	*2006*	*Q1*	$ -	$ -	$ -	-	0.00%	-	-
Feb-06	*2006*	*Q1*	-	$ -	$ -	-	0.00%	-	-
Mar-06	*2006*	*Q1*	-	$ -	$ -	-	0.00%	-	-
Apr-06	*2006*	*Q2*	-	$ -	$ -	-	4.14%	-	-
May-06	*2006*	*Q2*	-	$ -	$ -	-	4.14%	-	-
Jun-06	*2006*	*Q2*	-	$ -	$ -	-	4.14%	-	-
Jul-06	*2006*	*Q3*	-	$ -	$ -	-	4.59%	-	-
Aug-06	*2006*	*Q3*	-	$ -	$ -	-	4.59%	-	-
Sep-06	*2006*	*Q3*	-	$ -	$ -	-	4.59%	-	-
Oct-06	*2006*	*Q4*	-	$ -	$ -	-	4.59%	-	-
Nov-06	*2006*	*Q4*	-	$ -	$ -	-	4.59%	-	-
Dec-06	*2006*	*Q4*	-	$ -	$ -	-	4.59%	-	-
Jan-07	*2007*	*Q1*	-	$ -	$ -	-	4.59%	-	-
Feb-07	*2007*	*Q1*	-	$ -	$ -	-	4.59%	-	-
Mar-07	*2007*	*Q1*	-	$ -	$ -	-	4.59%	-	-
Apr-07	*2007*	*Q2*	-	$ -	$ -	-	4.59%	-	-
May-07	*2007*	*Q2*	-	$ -	$ -	-	4.59%	-	-
Jun-07	*2007*	*Q2*	-	$ -	$ -	-	4.59%	-	-
Jul-07	*2007*	*Q3*	-	$ -	$ -	-	4.59%	-	-
Aug-07	*2007*	*Q3*	-	$ -	$ -	-	4.59%	-	-
Sep-07	*2007*	*Q3*	-	$ -	$ -	-	4.59%	-	-
Oct-07	*2007*	*Q4*	-	$ -	$ -	-	5.14%	-	-
Nov-07	*2007*	*Q4*	-	$ -	$ -	-	5.14%	-	-
Dec-07	*2007*	*Q4*	-	$ -	$ -	-	5.14%	-	-
Jan-08	*2008*	*Q1*	-	$ -	$ -	-	5.14%	-	-
Feb-08	*2008*	*Q1*	-	$ -	$ -	-	5.14%	-	-
Mar-08	*2008*	*Q1*	-	$ -	$ -	-	5.14%	-	-
Apr-08	*2008*	*Q2*	-	$ -	$ -	-	4.08%	-	-
May-08	*2008*	*Q2*	-	$ -	$ -	-	4.08%	-	-
Jun-08	*2008*	*Q2*	-	$ -	$ -	-	4.08%	-	-
Jul-08	*2008*	*Q3*	-	$ -	$ -	-	3.35%	-	-
Aug-08	*2008*	*Q3*	-	$ -	$ -	-	3.35%	-	-
Sep-08	*2008*	*Q3*	-	$ -	$ -	-	3.35%	-	-
Oct-08	*2008*	*Q4*	-	$ -	$ -	-	3.35%	-	-
Nov-08	*2008*	*Q4*	-	$ -	$ -	-	3.35%	-	-

Dec-08	2008	Q4	-	$ -	$ -	-	3.35%	-	-
Jan-09	2009	Q1	-	$ 1,133.13	$ -	1,133.13	2.45%	-	-
Feb-09	2009	Q1	1,133.13	$ -	$ -	1,133.13	2.45%	2.31	2.31
Mar-09	2009	Q1	1,133.13	$ -	$ -	1,133.13	2.45%	2.31	4.63
Apr-09	2009	Q2	1,133.13	$ -	$ -	1,133.13	1.00%	0.94	5.57
May-09	2009	Q2	1,133.13	$ -	$ -	1,133.13	1.00%	0.94	6.52
Jun-09	2009	Q2	1,133.13	$ 235.67	$ -	1,368.80	1.00%	0.94	7.46
Jul-09	2009	Q3	1,368.80	$ 357.87	$ -	1,726.67	0.55%	0.63	8.09
Aug-09	2009	Q3	1,726.67	$ 947.74	$ -	2,674.41	0.55%	0.79	8.88
Sep-09	2009	Q3	2,674.41	$ -	$ -	2,674.41	0.55%	1.23	10.10
Oct-09	2009	Q4	2,674.41	$ -	$ -	2,674.41	0.55%	1.23	11.33
Nov-09	2009	Q4	2,674.41	$ 250.00	$ -	2,924.41	0.55%	1.23	12.56
Dec-09	2009	Q4	2,924.41	$ 2,217.97	$ -	5,142.38	0.55%	1.34	13.90
Jan-10	2010	Q1	5,142.38	$ -	$ 31,148.42	36,290.80	0.55%	2.36	16.25
Feb-10	2010	Q1	36,290.80	$ 1,186.80	$ 31,148.42	68,626.01	0.55%	16.63	32.89
Mar-10	2010	Q1	68,626.01	$ 4,296.71	$ 31,148.42	104,071.14	0.55%	31.45	64.34
Apr-10	2010	Q2	104,071.14	$ 2,377.20	$ 31,148.42	137,596.76	0.55%	47.70	112.04
May-10	2010	Q2	137,596.76	$ 4,695.32	$ 31,148.42	173,440.49	0.55%	63.07	175.10
Jun-10	2010	Q2	173,440.49	$ 3,063.48	$ 31,148.42	207,652.39	0.55%	79.49	254.60
Jul-10	2010	Q3	207,652.39	$ 5,239.50	$ 31,148.42	244,040.31	0.89%	154.01	408.61
Aug-10	2010	Q3	244,040.31	$ 541.39	$ 31,148.42	275,730.11	0.89%	181.00	589.60
Sep-10	2010	Q3	275,730.11	$ -	$ 31,148.42	306,878.53	0.89%	204.50	794.10
Oct-10	2010	Q4	306,878.53	$ 550.64	$ 31,148.42	338,577.59	1.20%	306.88	1,100.98
Nov-10	2010	Q4	338,577.59	$ 633.89	$ 31,148.42	370,359.89	1.20%	338.58	1,439.56
Dec-10	2010	Q4	370,359.89	$ -	$ 31,148.42	401,508.31	1.20%	370.36	1,809.92
Jan-11	2011	Q1	401,508.31	$ -	$ 26,280.33	427,788.64	1.47%	491.85	2,301.77
Feb-11	2011	Q1	427,788.64	$ -	$ 26,280.33	454,068.98	1.47%	524.04	2,825.81
Mar-11	2011	Q1	454,068.98	$ 3,967.95	$ 26,280.33	484,317.26	1.47%	556.23	3,382.04
Apr-11	2011	Q2	484,317.26	$ 1,934.42	$ 26,280.33	512,532.01	1.47%	593.29	3,975.33
May-11	2011	Q2	512,532.01	$ 1,996.41	$ 26,280.33	540,808.76	1.47%	627.85	4,603.18
Jun-11	2011	Q2	540,808.76	$ 2,010.05	$ 26,280.33	569,099.14	1.47%	662.49	5,265.67
Jul-11	2011	Q3	569,099.14	$ 297.78	$ 26,280.33	595,677.25	1.47%	697.15	5,962.82
Aug-11	2011	Q3	595,677.25	$ 4,042.98	$ 26,280.33	626,000.57	1.47%	729.70	6,692.52
Sep-11	2011	Q3	626,000.57	$ -	$ 26,280.33	652,280.90	1.47%	766.85	7,459.38
Oct-11	2011	Q4	652,280.90	$ 4,978.93	$ 26,280.33	683,540.16	1.47%	799.04	8,258.42
Nov-11	2011	Q4	683,540.16	$ 1,138.00	$ 26,280.33	710,958.50	1.47%	837.34	9,095.76
Dec-11	2011	Q4	710,958.50	$ 30,848.77	$ 26,280.33	768,087.60	1.47%	870.92	9,966.68
Jan-12	2012	Q1	768,087.60	$ 17,262.15	$ 26,776.67	812,126.42	1.47%	940.91	10,907.59
Feb-12	2012	Q1	812,126.42	$ 19,146.44	$ 26,776.67	858,049.52	1.47%	994.85	11,902.44
Mar-12	2012	Q1	858,049.52	$ 18,812.35	$ 26,776.67	903,638.54	1.47%	1,051.11	12,953.55
Apr-12	2012	Q2	903,638.54	$ 12,079.31	$ 26,776.67	942,494.52	1.47%	1,106.96	14,060.51
May-12	2012	Q2	942,494.52	$ 12,036.75	$ 26,776.67	981,307.93	1.47%	1,154.56	15,215.07
Jun-12	2012	Q2	981,307.93	$ 11,904.37	$ 26,776.67	1,019,988.97	1.47%	1,202.10	16,417.17
Jul-12	2012	Q3	1,019,988.97	$ 13,767.01	$ 26,776.67	1,060,532.65	1.47%	1,249.49	17,666.65
Aug-12	2012	Q3	1,060,532.65	$ 13,405.39	$ 26,776.67	1,100,714.70	1.47%	1,299.15	18,965.81
Sep-12	2012	Q3	1,100,714.70	$ 7,648.26	$ 26,776.67	1,135,139.63	1.47%	1,348.38	20,314.18
Oct-12	2012	Q4	1,135,139.63	$ 32,487.15	$ 26,776.67	1,194,403.45	1.47%	1,390.55	21,704.73
Nov-12	2012	Q4	1,194,403.45	$ 14,800.28	$ 26,776.67	1,235,980.39	1.47%	1,463.14	23,167.87
Dec-12	2012	Q4	1,235,980.39	$ 19,906.89	$ 26,776.67	1,282,663.95	1.47%	1,514.08	24,681.95
Jan-13	2013	Q1	1,282,663.95	$ 6,947.82	$ 26,776.67	1,316,388.44	1.47%	1,571.26	26,253.21
Feb-13	2013	Q1	1,316,388.44	$ 6,682.55	$ 26,776.67	1,349,847.65	1.47%	1,612.58	27,865.79
Mar-13	2013	Q1	1,349,847.65	$ 7,622.56	$ 26,776.67	1,384,246.88	1.47%	1,653.56	29,519.35
Apr-13	2013	Q2	1,384,246.88	$ 28,875.57	$ 26,776.67	1,439,899.12	1.47%	1,695.70	31,215.05
May-13	2013	Q2	1,439,899.12	$ 19,437.60	$ 26,776.67	1,486,113.38	1.47%	1,763.88	32,978.93
Jun-13	2013	Q2	1,486,113.38	$ 19,988.00	$ 26,776.67	1,532,878.05	1.47%	1,820.49	34,799.42
Jul-13	2013	Q3	1,532,878.05	$ 19,419.16	$ 26,776.67	1,579,073.88	1.47%	1,877.78	36,677.20
Aug-13	2013	Q3	1,579,073.88	$ 14,269.71	$ 26,776.67	1,620,120.25	1.47%	1,934.37	38,611.56
Sep-13	2013	Q3	1,620,120.25	$ 17,233.89	$ 26,776.67	1,664,130.81	1.47%	1,984.65	40,596.21
Oct-13	2013	Q4	1,664,130.81	$ 13,700.00	$ 26,776.67	1,704,607.48	1.47%	2,038.56	42,634.77
Nov-13	2013	Q4	1,704,607.48	$ 13,700.00	$ 26,776.67	1,745,084.14	1.47%	2,088.14	44,722.91
Dec-13	2013	Q4	1,745,084.14	$ 19,600.00	$ 26,776.67	1,791,460.81	1.47%	2,137.73	46,860.64

$	272,198.95	$	1,010,465.00	$	1,282,663.95

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ -	$ 426.92	$ 426.92	$ 213.46	4.37%	$ 9.32
2007	$ -	$ 1,279.29	$ 1,706.21	$ 1,066.56	4.73%	$ 50.42
2008	$ -	$ 2,848.61	$ 4,554.81	$ 3,130.51	3.98%	$ 124.59
2009	$ 5,142.38	$ 65,839.76	$ 75,536.96	$ 40,045.88	1.14%	$ 455.52
2010	$ 22,584.93	$ 230,693.04	$ 328,814.93	$ 202,175.94	0.80%	$ 1,612.35
2011	$ 51,215.29	$ 346,016.63	$ 726,046.85	$ 527,430.89	1.47%	$ 7,753.23
2012	$ 193,256.35	$ 361,218.48	$ 1,280,521.68	$ 1,003,284.26	1.47%	$ 14,748.28
2013	$ 187,476.86	$ 364,102.74	$ 1,832,101.28	$ 1,556,311.48	1.47%	$ 22,877.78
Cumulative Interest to 2011						$ 10,005.44
Cumulative Interest to 2012						$ 24,753.72
Cumulative Interest to 2013						$ 47,631.50

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This workshee any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that curr will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board al SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approve The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effec initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to suppo This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's cir such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requireme related costs to December 31, 2012 and associated OM&A.**

		2006		**2007**		**2008**
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$	1,017.97	$	2,974.45	$	6,411.79
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$	-	$	-	$	-

X	Sheet 8A (Interest calculated on monthly balances)	$	-	$	-	$	-
	Sheet 8B (Interest calculated on average annual balances)						

SMFA Revenues (from Sheet 8)	$	80,490.33	$	121,940.44	$	123,807.03
SMFA Interest (from Sheet 8)	$	1,042.06	$	6,517.91	$	10,087.90
Net Deferred Revenue Requirement	-$	80,514.42	-$	125,483.90	-$	127,483.14

Number of Metered Customers (average for 2013 test year)
- Number of metered customers for which smart meter were deployed as part of program). Residential and GS < 50 kW customer classes and any other metered and ODS assets)

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding			1
Deferred Incremental Revenue Requirement from 2006 to December 31, 2012 plus Interest on OM&A and Amortization		$	2,414,747.25
SMFA Revenues collected from 2006 to 2013 test year (inclusive) Plus Simple Interest on SMFA Revenues		$	2,819,268.43
Net Deferred Revenue Requirement		-$	404,521.18
SMDR	May 1, 2012 to April 30, 2013	-$	0.88
Check: Forecasted SMDR Revenues		-$	404,817.60
Check: Forecasted SMIRR Revenues		$	860,237.40

Match

worksheet also c
d that current fundin
ne Board also noted
is approved by th
was in effect. The S
e to support its p
butor's circumsta

requirement associated with the recovery

	2009	2010	2011	2012	2013	Total
	$ 152,305.66	$ 528,755.13	$ 772,046.77	$ 926,553.53	$ 861,839.06	$ 2,390,065.30
	$ 13.90	$ 1,796.02	$ 8,156.76	$ 14,715.27		$ 24,681.95

$	13.90	$	1,796.02	$	8,156.76	$	14,715.27	$	22,178.69	$	24,681.95
$	339,249.12	$	765,601.38	$	938,001.22	$	314,579.46	$	-	$	2,683,668.98
$	4,453.83	$	8,230.79	$	27,329.53	$	38,487.55	$	39,449.88	$	135,599.45
-$	191,383.40	-$	243,281.01	-$	185,127.22	$	588,201.79	$	822,389.18	-$	404,521.18

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ed classes involved (e.g. GS 50 to 4999 kW for which interval meters were upgraded to utilize AM

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the class-specific SMDRs according to accepted practice. A distributor may choose to use its own methodology, but should provide analogous support for its allocation and derivation of class-specific SMDRs and SMIRRs.

Class-specific SMDRs

Revenue Requirement for Historical Years	2006	2007	2008	2009	2010	2011	2012	Total 2006 to 2012
Return on Capital	$ 452.20	$ 1,323.87	$ 2,846.46	$ 68,659.64	$ 233,624.84	$ 320,454.26	$ 313,125.70	$ 940,486.98
Depreciation/Amortization expense and related interest	$ 426.92	$ 1,279.29	$ 2,848.61	$ 65,839.76	$ 230,693.04	$ 346,016.63	$ 361,218.48	
	$ -	$ -	$ -	$ 12.89	$ 1,635.87	$ 7,105.11	$ 9,586.42	
	$ 426.92	$ 1,279.29	$ 2,848.61	$ 65,852.65	$ 232,328.91	$ 353,121.74	$ 370,804.90	$ 1,026,663.01
Operating Expenses and related interest	$ -	$ -	$ -	$ 5,142.38	$ 22,584.93	$ 51,215.29	$ 193,256.35	
	$ -	$ -	$ -	$ 1.01	$ 160.15	$ 1,051.65	$ 5,128.85	

Explanation / Allocator	Residential	GS < 50 kW	GS 50 to 4999 kW
Check Row if SMDR/SMIRR apply to class	X	X	
	%	%	%
Weighted Meter Cost - Capital	73.91%	26.09%	
Allocated per class	$ 695,116.55	$ 245,370.43	$ -
Weighted Meter Cost - Capital	74%	26%	0%
Allocated per class	$ 758,809.49	$ 267,853.52	$ -
	#	#	#
Number of Smart Meters installed by Class	35,364	2,733	

Smart Meter Model for Electricity Distributors (2013 Filers)

This worksheet calculates the class-specific SMIRRs according to accepted practice. A distributor may choose to use its own methodology, but should provide analogous suppor for its allocation and derivation of class-specific SMDRs and SMIRRs.

Class-specific SMDRs

Revenue Requirement for 2013	2013	**Explanation / Allocator**	Residential	GS < 50 kW	GS 50 to 4999 kW
		Check Row if SMDR/SMIRR apply to class	X	X	
			%	%	%
		Weighted Meter Cost - Capital	73.91%	26.09%	0.00%
Return on Capital	$ 248,761.32	Allocated per class	$ 183,860.18	$ 64,901.13	$ -
Depreciation/Amortization expense		Weighted Meter Cost - Capital	73.91%	26.09%	0.00%
	$ 364,102.74	Allocated per class	$ 269,109.35	$ 94,993.39	$ -
Operating Expenses	$ 187,476.86				
			#	#	#
		Number of Smart Meters installed by Class	35,364	2,733	-

ATTACHMENT R

REFERENCE: Chapter 2 Appendices Revisions

The following are revisions to the Chapter 2 Appendices

Updated Appendix 2-B

FA Cont 2012 – revised additions and disposals (Cost & Accumulated Depreciation sections) to actual data for 2012 as per 2-Energy Probe-9 (a) interrogatory.

FA Cont 2013 – revised to reflect actual data for 2012, along with actual expenditures closed to rate base in 2013 along with the remaining forecast for 2013 test year.

Updated Appendix 2F

- 2012 actuals (3-SEC-10, 3-EP-18 a)
- 2013 most recent YTD, and 2012 same YTD month (3-EP-18 c)

Updated Appendix 2G with 2013 Year-to-Date Actuals (4-SEC-12)

- Correct version of 2-CG and 2-CH (4-EP-23)

Updated Appendix 2W

- Updated rates resulting from: Cost of Power Non-RPP correction; Load forecast with Negative Impact Variable that uses the Half-Year rule for CDM; 2012
- Actuals update to Trial Balance; Updated RTSR Model; Updates to Smart Meter and Stranded Meter Rate Riders. (1-Staff-3)

Filing Requiremer
Transmission and Distr
Chapter 2 A

Utility Name	Brantford Power Inc.
Service Territory	Brantford ON
Assigned EB Number	EB-2012-0109
Name of Contact and Title	Heather Wyatt, Director of Regulatory Affairs, Board Secretary
Phone Number	519-751-3522 X 3269
Email Address	Hwyatt@brantford.ca
Bridge Year	2012
Test Year	2013
Last Rebasing Year	2008

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate ite

White cells contain fixed values, automatically generated values or formulae.

nts for Electricity
tribution Applications
ppendicies

Version 1.1

m from the drop-down list.

Filing Requirements for Transmission and Distribution Applications
Chapter 2 Appendicies

Appendix 2-A
Capital Projects Table

Projects	2008	Projects	2009	Projects	2010	Projects
Reporting Basis	CGAP		CGAP		CGAP	
Capital Project #1- Residential Seconary Services	$ 93,448	Capital Project #1- Residential Seconary Services	$ 112,524	Capital Project #1- Residential Seconary Services	$ 156,047	Capital Project #1- Residential Seconary Services
Capital Project #2 - Overhead Line Extensions	$ 263,594	Capital Project #2 - Overhead Line Extensions	$ 206,127	Capital Project #2 - Overhead Line Extensions	$ 354,061	Capital Project #2 - Overhead Line Extensions
Capital Project #3 - Underground Line Extensions	$ 330,157	Capital Project #3 - Underground Line Extensions	$ 236,335	Capital Project #3 - Underground Line Extensions	$ 483,721	Capital Project #3 - Underground Line Extensions
Capital Project #4 -Overhead Transformers	$ 314,189	Capital Project #4 - Overhead Transformers	$ 202,555	Capital Project #4- Underground Transformers	$ 593,583	Capital Project #4 - Overhead Transformers
Capital Project #5 - Underground Transformers	$ 617,980	Capital Project #5 - Underground Transformers	$ 277,149	Capital Project #5- Powerline Feeder Upgrades	$ 524,514	Capital Project #5 - Underground Transformers
Capital Project #6- New Subdivisions and Townhomes	$ 838,213	Capital Project #6 - Powerline Feeder Upgrades	$ 353,641	Capital Projects #6 - New Subdivisions and Townhomes	$ 265,408	Capital Project #6 - Powerline Feeder Upgrades
Capital Project #7City/Ministry of Transportation Relocates	$ 103,262	Capital Project #7 - New Subdivisions and Townhomes	$ 1,654,016	Capital Project #7 - Scada & Distribution/ System Upgrade to Windows	$ 246,707	Capital Projects #7 - New Subdivisions and Townhomes
Capital Project #8 - Scada & Distribution Automation/Brantford General Hospital Automatic Load Transfer System	$ 179,175	Capital Project #8 - Scada & Distribution Automation/Reloser Installation	$ 96,919	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ 432,011	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds
Capital Project #9- Conversion of Lines from 4 & 8 Kv to 27 KvSystem - Applewood & Brier Park Subdivision	$ 1,960,631	Capital Project #9 - Conversion of Lines from 4 & 8 Kv to 27 Kv System - Tranquility, Rosewood, etc.	$ 1,402,272	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park	$ 1,537,546	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park/Dunsdon Rebuild
Capital Project #10- Annual Pole Replacements - General Yearly Rebuilds	$ 471,404	Capital Project #10 - Annual Pole Replacements - General Yearly Rebuilds	$ 512,324	Capital Project #10-- Metering	$ 355,369	Capital Project #10 - Asset Management & Consultancy Software
Capital Project #11 - AM/FM GIS System Upgrade	$ 241,944	Capital Project #11 - Testing of G-Technology Version 9.4	$ 70,814	Capital Project #11-- Wholesale Metering (Brantford TS)	$ 769,365	Capital Project #11 Upgrade to G-Technology Version 10
Capital Project #12 - Metering	$ 229,050	Capital Project #12 - Metering	$ 349,517	Capital Project #12- Replacement of Vehicles	$ 248,832	Capital Project #12 - Metering
Capital Project #13 - Replacement of Vehicles	$ 165,750	Capital Project #13 - Replacement of Vehicles	$ 312,919			Capital Project #13-- Wholesale Metering (Brantford TS)
						Capital Project #14 - Replacement of Vehicles
Capital Contributions	-$ 627,570	Capital Contributions	-$ 745,257	Capital Contribtuions	-$ 196,588	Capital Contributions
Sub Total:	$ 5,181,227	Sub Total:	$ 5,041,855	Sub Total:	$ 5,770,576	Sub Total:
Miscellaneous	$ 22,289	Miscellaneous	-$ 88,042	Miscellaneous	$ 101,275	Miscellaneous
Total:	$ 5,158,938	Total	$ 5,129,897	Total:	$ 5,669,301	Total:

Notes:

1 Please provide a breakdown of the major components of each capital project. Please ensure that all projects below the materiality threshold are i

2 Amounts should be reported on a MIFRS basis for the adoption year and any subsequent years, only.

File Number:	EB-2012-0109
Exhibit:	2
Tab:	
Schedule:	
Page:	2
Date:	July 17,2013

Appendix 2-B
Fixed Asset Continuity Schedule

Year 2008

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)					$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 208,241	-$ 20,312	$ -	$ 187,929	$ -	$ -	$ -	$ -	$ 187,929
CEC	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1808	Buildings		$ 1,192,568	-$ 28,837	$ -	$ 1,163,732	-$ 82,210	-$ 23,274	$ 4,048	-$ 101,436	$ 1,062,296
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541	$ -	$ -	$ 4,469,541	-$ 332,907	-$ 111,739	$ -	-$ 444,646	$ 4,024,895
47	1820	Distribution Station Equipment <50 kV		$ 140,683	-$ 66,256	$ -	$ 74,427	-$ 33,449	-$ 2,480	$ 15,828	-$ 20,101	$ 54,326
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 13,076,251	$ 610,799	$ -	$ 13,687,050	-$ 3,383,375	-$ 547,481	$ -	-$ 3,930,856	$ 9,756,194
47	1835	Overhead Conductors & Devices		$ 9,890,796	$ 570,913	$ -	$ 10,461,708	-$ 2,069,539	-$ 418,481	$ -	-$ 2,488,019	$ 7,973,689
47	1840	Underground Conduit		$ 10,628,960	$ 641,725	$ -	$ 11,270,685	-$ 2,809,075	-$ 450,828	$ -	-$ 3,259,903	$ 8,010,782
47	1845	Underground Conductors & Devices		$ 11,158,523	$ 1,856,542	$ -	$ 13,015,065	-$ 1,580,663	-$ 534,022	$ -	-$ 2,114,685	$ 10,900,380
47	1850	Line Transformers		$ 13,619,321	$ 1,180,002	$ -	$ 14,799,323	-$ 3,103,832	-$ 595,764	$ -	-$ 3,699,596	$ 11,099,727
47	1855	Services (Overhead & Underground)		$ 637,358	$ 103,915	$ -	$ 741,273	-$ 47,749	-$ 36,874	$ -	-$ 84,623	$ 656,650
47	1860	Meters		$ 6,960,135	$ 259,720	$ -	$ 7,219,856	-$ 1,537,900	-$ 288,812	$ -	-$ 1,826,713	$ 5,393,143
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ -	$ 167,826	$ -	$ 167,826	$ -	-$ 33,566	$ -	-$ 33,566	$ 134,260
10	1930	Transportation Equipment		$ 2,352,981	$ 164,863	-$ 49,409	$ 2,468,434	-$ 1,438,613	-$ 246,533	$ 49,409	-$ 1,635,736	$ 832,698
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 110,829	$ 31,935	$ -	$ 142,764	-$ 49,094	-$ 14,272	$ -	-$ 63,366	$ 79,398
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 1,176	$ -	$ -	$ 1,176	-$ 471	-$ 236	$ -	-$ 707	$ 469
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1970	Load Management Controls - Customer Premises		$ 547,972	$ -	$ -	$ 547,972	-$ 392,711	-$ 54,797	$ -	-$ 447,508	$ 100,464
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 148,397	$ 198,266	$ -	$ 346,663	-$ 9,895	-$ 23,107	$ -	-$ 33,002	$ 313,661
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 2,016,598	-$ 627,570	$ -	-$ 2,644,169	$ 145,935	$ 105,762	$ -	$ 251,698	-$ 2,392,471
N/A	2040	Plant Held for Future Use			$ 115,404		$ 115,404			-$ 19,876	-$ 19,876	$ 95,528
	etc.										$ -	$ -
		Total		**$ 73,127,134**	**$ 5,158,937**	**-$ 49,409**	**$ 78,236,661**	**-$ 16,725,548**	**-$ 3,276,505**	**$ 49,409**	**-$ 19,952,643**	**$ 58,284,018**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ 246,533
Stores Equipment	$ -
Net Depreciation	$ 3,029,972

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA

Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

File Number:	EB-2012-0109
Exhibit:	2
Tab:	
Schedule:	
Page:	3
Date:	July 17,2013

Appendix 2-B
Fixed Asset Continuity Schedule

Year 2009

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 187,929	-$ 5,968	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ -	$ 5,968	$ -	$ 5,968	$ -	$ -	$ -	$ -	$ 5,968
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ 1,163,732	-$ 101,436	-$ 23,274	$ -	-$ 124,710	$ 1,039,022
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541	$ -	$ -	$ 4,469,541	-$ 444,646	-$ 111,739	$ -	-$ 556,385	$ 3,913,156
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ 74,427	-$ 20,101	-$ 2,481	$ -	-$ 22,582	$ 51,845
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 13,687,050	$ 828,621	$ -	$ 14,515,671	-$ 3,930,856	-$ 580,647	$ -	-$ 4,511,503	$ 10,004,168
47	1835	Overhead Conductors & Devices		$ 10,461,708	$ 468,598	$ -	$ 10,930,306	-$ 2,488,019	-$ 437,210	$ -	-$ 2,925,229	$ 8,005,077
47	1840	Underground Conduit		$ 11,270,685	$ 681,004	$ -	$ 11,951,689	-$ 3,259,903	-$ 478,072	$ -	-$ 3,737,975	$ 8,213,714
47	1845	Underground Conductors & Devices		$ 13,015,065	$ 1,877,443	$ -	$ 14,892,508	-$ 2,114,685	-$ 609,145	$ -	-$ 2,723,830	$ 12,168,678
47	1850	Line Transformers		$ 14,799,323	$ 973,674	$ -	$ 15,772,997	-$ 3,699,596	-$ 634,684	$ -	-$ 4,334,280	$ 11,438,717
47	1855	Services (Overhead & Underground)		$ 741,273	$ 146,412	$ -	$ 887,685	-$ 84,623	-$ 41,314	$ -	-$ 125,937	$ 761,748
47	1860	Meters		$ 7,219,856	$ 424,756	$ -	$ 7,644,612	-$ 1,826,713	-$ 241,581	$ -	-$ 2,068,293	$ 5,576,318
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 167,826	$ 28,529	$ -	$ 196,355	-$ 33,566	-$ 39,270	$ -	-$ 72,836	$ 123,519
10	1930	Transportation Equipment		$ 2,468,434	$ 312,919	-$ 100,056	$ 2,681,297	-$ 1,635,736	-$ 275,557	$ 100,056	-$ 1,811,237	$ 870,060
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 142,764	$ 35,793	$ -	$ 178,557	-$ 63,366	-$ 17,859	$ -	-$ 81,225	$ 97,332
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 1,176	$ -	$ -	$ 1,176	-$ 707	-$ 236	$ -	-$ 943	$ 233
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1970	Load Management Controls - Customer Premises		$ 547,972	$ -	$ -	$ 547,972	-$ 447,508	-$ 54,797	$ -	-$ 502,305	$ 45,667
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 346,663	$ 97,406	$ -	$ 444,069	-$ 33,002	-$ 29,731	$ -	-$ 62,733	$ 381,336
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 2,644,169	-$ 745,257	$ -	-$ 3,389,425	$ 251,698	$ 135,584	$ -	$ 387,281	-$ 3,002,144
N/A	2040	Plant Held for Future Use		$ 115,404	$ 17,515	-$ 95,592	$ 37,327	-$ 19,876	$ -	$ 19,876	$ -	$ 37,327
	etc.						$ -				$ -	$ -
		Total		**$ 78,236,661**	**$ 5,147,412**	**-$ 195,649**	**$ 83,188,424**	**-$ 19,952,643**	**-$ 3,442,012**	**$ 119,933**	**-$ 23,274,722**	**$ 59,913,702**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ 275,557
Stores Equipment	
Net Depreciation	$ 3,166,455

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

Fixed

CCA Class	OEB	Description	Depreciation Rate	Opening Balance
12	1611	Computer Software (Formally known as Account 1925)		$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -
N/A	1805	Land		$ 181,961
CEC	1806	Land Rights		$ 5,968
47	1808	Buildings		$ 1,163,732
13	1810	Leasehold Improvements		$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541
47	1820	Distribution Station Equipment <50 kV		$ 74,427
47	1825	Storage Battery Equipment		$ -
47	1830	Poles, Towers & Fixtures		$ 14,515,671
47	1835	Overhead Conductors & Devices		$ 10,930,306
47	1840	Underground Conduit		$ 11,951,689
47	1845	Underground Conductors & Devices		$ 14,892,508
47	1850	Line Transformers		$ 15,772,997
47	1855	Services (Overhead & Underground)		$ 887,685
47	1860	Meters		$ 7,644,612
47	1860	Meters (Smart Meters)		$ -
N/A	1905	Land		$ -
47	1908	Buildings & Fixtures		$ -
13	1910	Leasehold Improvements		$ -
8	1915	Office Furniture & Equipment (10 years)		$ -
8	1915	Office Furniture & Equipment (5 years)		$ -
10	1920	Computer Equipment - Hardware		$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -
	1925	Computer Software		$ 196,355
10	1930	Transportation Equipment		$ 2,681,297
8	1935	Stores Equipment		$ -
8	1940	Tools, Shop & Garage Equipment		$ 178,557
8	1945	Measurement & Testing Equipment		$ -
8	1950	Power Operated Equipment		$ -
8	1955	Communications Equipment		$ 1,176
8	1955	Communication Equipment (Smart Meters)		$ -
8	1960	Miscellaneous Equipment		$ -

	1970	Load Management Controls - Customer Premises		$ 547,972
47	1975	Load Management Controls Utility Premises		$ -
47	1980	System Supervisor Equipment		$ 444,069
47	1985	Miscellaneous Fixed Assets		$ -
47	1995	Contributions & Grants		-$ 3,389,425
N/A	2040	Plant Held for Future Use		$ 37,327
	etc.			$ -
				$ -
		Total		**$ 83,188,424**

10		Transportation
8		Stores Equipment

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted f historical years back to its last rebasing; or 2) at least three years of historical actuals, in ad

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes ir Classes for tax purposes. If an applicant uses any different classes from those shown in the

3 The table may need to be customized for a utility's asset categories or for any new asset ac

4 The depreciation column (D) is not required as the relevant information will be provided in tl

Appendix 2-B

d Asset Continuity Schedule

Year **2010**

Cost			Accumulated Depreciation		
Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ 181,961	$ -	$ -	$ -
$ -	$ -	$ 5,968	$ -	$ -	$ -
$ -	$ -	$ 1,163,732	-$ 124,710	-$ 23,274	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ 4,469,541	-$ 556,385	-$ 111,739	$ -
$ -	$ -	$ 74,427	-$ 22,582	-$ 2,481	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 778,060	$ -	$ 15,293,731	-$ 4,511,503	-$ 611,734	$ -
$ 530,675	$ -	$ 11,460,981	-$ 2,925,229	-$ 458,439	$ -
$ 647,491	$ -	$ 12,599,181	-$ 3,737,975	-$ 503,959	$ -
$ 1,378,158	$ -	$ 16,270,666	-$ 2,723,830	-$ 623,972	$ -
$ 781,090	$ -	$ 16,554,086	-$ 4,334,280	-$ 654,598	$ -
$ 189,738	$ -	$ 1,077,423	-$ 125,937	-$ 31,495	$ -
$ 1,088,510	$ -	$ 8,733,121	-$ 2,068,293	-$ 349,469	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 31	$ -	$ 196,386	-$ 72,836	-$ 39,278	$ -
$ 248,832	-$ 206,784	$ 2,723,344	-$ 1,811,237	-$ 266,240	$ 206,784
$ -	$ -	$ -	$ -	$ -	$ -
$ 14,757	$ -	$ 193,313	-$ 81,225	-$ 18,422	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ 1,176	-$ 943	-$ 233	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -

$ -	$ -	$ 547,972		-$ 502,305	-$ 45,667	$ -
$ -	$ -	$ -		$ -	$ -	$ -
$ 208,548	$ -	$ 652,617		-$ 62,733	-$ 43,509	$ -
$ -	$ -	$ -		$ -	$ -	$ -
-$ 196,588	$ -	-$ 3,586,013		$ 387,281	$ 143,429	$ -
$ 52,910	-$ 38,421	$ 51,816		$ -	$ -	$ -
		$ -				
$ 5,722,212	**-$ 245,206**	**$ 88,665,431**		**-$ 23,274,722**	**-$ 3,641,081**	**$ 206,784**

Less: *Fully Allocated Depreciation*	
Transportation	$ 266,240
Stores Equipment	
Net Depreciation	$ 3,374,841

or the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must pr
ldition to Bridge Year and Test Year forecasts.

n Tax Returns. Fixed Assets sub-components may be used where the underlying asset components
e table, an explanation should be provided. (also see note 3 below).

ccounts announced or authorized by the Board.

he following 2-C series of appendices.

File Number: EB-2012-0109
Exhibit: 2
Tab:
Schedule:
Page: 4

Date: July 17,2013

Closing Balance	Net Book Value
$ -	$ -
$ -	$ -
$ -	$ 181,961
$ -	$ 5,968
-$ 147,984	$ 1,015,748
$ -	$ -
-$ 668,124	$ 3,801,417
-$ 25,063	$ 49,364
$ -	$ -
-$ 5,123,237	$ 10,170,494
-$ 3,383,668	$ 8,077,313
-$ 4,241,935	$ 8,357,246
-$ 3,347,803	$ 12,922,864
-$ 4,988,877	$ 11,565,209
-$ 157,432	$ 919,991
-$ 2,417,762	$ 6,315,359
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
-$ 112,114	$ 84,272
-$ 1,870,692	$ 852,652
$ -	$ -
-$ 99,646	$ 93,667
$ -	$ -
$ -	$ -
-$ 1,176	$ -
$ -	$ -
$ -	$ -

-$ 547,972	$ -
$ -	$ -
-$ 106,243	$ 546,375
$ -	$ -
$ 530,710	-$ 3,055,303
$ -	$ 51,816
$ -	$ -
-$ 26,709,019	**$ 61,956,412**

ovide data for the earlier of: 1) all

are classified under multiple CCA

File Number:	EB-2012-0109
Exhibit:	2
Tab:	
Schedule:	
Page:	5
Date:	July 17,2013

Appendix 2-B
Fixed Asset Continuity Schedule

Year 2011

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land		$ 181,961	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ 5,968	$ -	$ -	$ 5,968	$ -	$ -	$ -	$ -	$ 5,968
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ 1,163,732	-$ 147,984	-$ 23,274	$ -	-$ 171,258	$ 992,474
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541	$ 38,370	$ -	$ 4,507,912	-$ 668,124	-$ 112,708	$ -	-$ 780,833	$ 3,727,079
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ 74,427	-$ 25,063	-$ 2,481	$ -	-$ 27,544	$ 46,883
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 15,293,731	$ 680,278	$ -	$ 15,974,010	-$ 5,123,237	-$ 638,939	$ -	-$ 5,762,177	$ 10,211,833
47	1835	Overhead Conductors & Devices		$ 11,460,981	$ 655,233	$ -	$ 12,116,215	-$ 3,383,668	-$ 484,656	$ -	-$ 3,868,325	$ 8,247,890
47	1840	Underground Conduit		$ 12,599,181	$ 686,869	$ -	$ 13,286,049	-$ 4,241,935	-$ 531,437	$ -	-$ 4,773,371	$ 8,512,678
47	1845	Underground Conductors & Devices		$ 16,270,666	$ 1,145,510	$ -	$ 17,416,176	-$ 3,347,803	-$ 696,655	$ -	-$ 4,044,458	$ 13,371,719
47	1850	Line Transformers		$ 16,554,086	$ 478,372	$ -	$ 17,032,458	-$ 4,988,877	-$ 681,295	$ -	-$ 5,670,172	$ 11,362,286
47	1855	Services (Overhead & Underground)		$ 1,077,423	$ 191,941	$ -	$ 1,269,364	-$ 157,432	-$ 50,766	$ -	-$ 208,198	$ 1,061,166
47	1860	Meters		$ 8,733,121	$ 411,892	$ -	$ 9,145,013	-$ 2,417,762	-$ 629,086	$ -	-$ 3,046,849	$ 6,098,164
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 196,386	$ 238,943	$ -	$ 435,329	-$ 112,114	-$ 87,064	$ -	-$ 199,178	$ 236,151
10	1930	Transportation Equipment		$ 2,723,344	$ 309,767	$ -	$ 3,033,111	-$ 1,870,692	-$ 271,416	$ -	-$ 2,142,108	$ 891,003
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 193,313	$ 1,380	-$ 54,401	$ 140,292	-$ 99,646	-$ 14,030	$ 54,401	-$ 59,275	$ 81,017
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 1,176	$ -	-$ 1,176	$ -	-$ 1,176	$ -	$ 1,176	$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls - Customer Premises		$ 547,972	$ -	-$ 547,972	$ -	-$ 547,972	$ -	$ 547,972	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 652,617	$ 7,702	$ -	$ 660,319	-$ 106,243	-$ 43,982	$ -	-$ 150,224	$ 510,095
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 3,586,013	-$ 265,560	$ -	-$ 3,851,573	$ 530,710	$ 154,073	$ -	$ 684,783	-$ 3,166,790
N/A	2040	Plant Held for Future Use		$ 51,816	$ 2,940	$ -	$ 54,756	$ -	$ -	$ -	$ -	$ 54,756
	etc.						$ -					
		Total		**$ 88,665,431**	**$ 4,583,636**	**-$ 603,550**	**$ 92,645,518**	**-$ 26,709,019**	**-$ 4,113,716**	**$ 603,550**	**-$ 30,219,185**	**$ 62,426,332**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ 271,416
Stores Equipment	
Net Depreciation	$ 3,842,300

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA

Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

Fixed

CCA Class	OEB	Description	Depreciation Rate	Opening Balance
12	1611	Computer Software (Formally known as Account 1925)		$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -
N/A	1805	Land		$ 181,961
CEC	1806	Land Rights		$ 5,968
47	1808	Buildings		$ 1,163,732
13	1810	Leasehold Improvements		$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,507,912
47	1820	Distribution Station Equipment <50 kV		$ 74,427
47	1825	Storage Battery Equipment		$ -
47	1830	Poles, Towers & Fixtures		$ 15,974,010
47	1835	Overhead Conductors & Devices		$ 12,116,215
47	1840	Underground Conduit		$ 13,286,049
47	1845	Underground Conductors & Devices		$ 17,416,176
47	1850	Line Transformers		$ 17,032,458
47	1855	Services (Overhead & Underground)		$ 1,269,364
47	1860	Meters		$ 9,145,013
47	1860	Meters (Smart Meters)		$ -
N/A	1905	Land		$ -
47	1908	Buildings & Fixtures		$ -
13	1910	Leasehold Improvements		$ -
8	1915	Office Furniture & Equipment (10 years)		$ -
8	1915	Office Furniture & Equipment (5 years)		$ -
10	1920	Computer Equipment - Hardware		$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -
	1925	Computer Software		$ 435,329
10	1930	Transportation Equipment		$ 3,033,111
8	1935	Stores Equipment		$ -
8	1940	Tools, Shop & Garage Equipment		$ 140,292
8	1945	Measurement & Testing Equipment		$ -
8	1950	Power Operated Equipment		$ -
8	1955	Communications Equipment		$ -
8	1955	Communication Equipment (Smart Meters)		$ -
8	1960	Miscellaneous Equipment		$ -

47	1970	Load Management Controls - Customer Premises		$ -
47	1975	Load Management Controls Utility Premises		$ -
47	1980	System Supervisor Equipment		$ 660,319
47	1985	Miscellaneous Fixed Assets		$ -
47	1995	Contributions & Grants		-$ 3,851,573
N/A	2040	Plant Held for Future Use		$ 54,756
	etc.			$ -
				$ -
		Total		**$ 92,645,518**

10		Transportation
8		Stores Equipment

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted f historical years back to its last rebasing; or 2) at least three years of historical actuals, in ad

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes ir Classes for tax purposes. If an applicant uses any different classes from those shown in the

3 The table may need to be customized for a utility's asset categories or for any new asset ac

4 The depreciation column (D) is not required as the relevant information will be provided in tl

Appendix 2-B
d Asset Continuity Schedule

Year **2012**

Cost			Accumulated Depreciation		
Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals
$ 200,139	$ -	$ 200,139	$ -	-$ 127,093	-$ 199,178
$ 89,022	$ -	$ 89,022	$ -	-$ 7,748	$ -
$ -	$ -	$ 181,961	$ -	$ -	$ -
$ -	$ -	$ 5,968		$ -	$ -
$ -	$ -	$ 1,163,732	-$ 171,258	-$ 23,274	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ 4,507,912	-$ 780,833	-$ 112,698	$ -
$ -	$ -	$ 74,427	-$ 27,544	-$ 2,481	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 992,406	$ -	$ 16,966,416	-$ 5,762,177	-$ 678,663	$ -
$ 434,529	$ -	$ 12,550,744	-$ 3,868,325	-$ 505,205	$ -
$ 572,484	$ -	$ 13,858,533	-$ 4,773,371	-$ 554,351	$ -
$ 1,177,665	$ -	$ 18,593,842	-$ 4,044,458	-$ 743,742	$ -
$ 351,314	$ -	$ 17,383,772	-$ 5,670,172	-$ 695,340	$ -
$ 294,421	$ -	$ 1,563,785	-$ 208,198	-$ 62,548	$ -
$ 158,377	-$ 5,381,879	$ 3,921,511	-$ 3,046,849	-$ 173,440	$ 2,215,921
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 3,113	$ -	$ 3,113	$ -	-$ 314	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 103,440	$ -	$ 103,440	$ -	-$ 25,860	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ 435,329	-$ 199,178	$ -	$ 199,178
$ 123,836	-$ 227,958	$ 2,928,990	-$ 2,142,108	-$ 218,541	$ 227,958
$ -	$ -	$ -	$ -	$ -	$ -
$ 3,700	$ -	$ 143,992	-$ 59,275	-$ 14,400	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -

$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 37,018	$ -	$ 697,337	-$ 150,224	-$ 46,535	$ -
$ -	$ -	$ -	$ -	$ -	$ -
-$ 605,551	$ -	-$ 4,457,124	$ 684,783	$ 178,286	$ -
$ -	-$ 54,756	-$ 0	$ -	$ -	$ -
		$ -			
$ 3,935,915	**-$ 5,664,593**	**$ 90,916,839**	**-$ 30,219,185**	**-$ 3,813,949**	**$ 2,443,879**

Less: *Fully Allocated Depreciation*	
Transportation	$ 203,065
Stores Equipment	
Net Depreciation	$ 3,610,884

or the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must pr
ldition to Bridge Year and Test Year forecasts.

n Tax Returns. Fixed Assets sub-components may be used where the underlying asset components
e table, an explanation should be provided. (also see note 3 below).

ccounts announced or authorized by the Board.

he following 2-C series of appendices.

File Number: EB-2012-0109
Exhibit: 2
Tab:
Schedule:
Page: 6

Date: July 17,2013

Closing Balance	Net Book Value
-$ 326,271	-$ 126,132
-$ 7,748	$ 81,274
$ -	$ 181,961
$ -	$ 5,968
-$ 194,532	$ 969,200
$ -	$ -
-$ 893,531	$ 3,614,381
-$ 30,025	$ 44,402
$ -	$ -
-$ 6,440,840	$ 10,525,576
-$ 4,373,530	$ 8,177,214
-$ 5,327,722	$ 8,530,811
-$ 4,788,200	$ 13,805,642
-$ 6,365,512	$ 11,018,260
-$ 270,746	$ 1,293,039
-$ 1,004,368	$ 2,917,143
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
-$ 314	$ 2,799
$ -	$ -
-$ 25,860	$ 77,580
$ -	$ -
$ -	$ -
$ -	$ 435,329
-$ 2,132,692	$ 796,298
$ -	$ -
-$ 73,675	$ 70,317
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -
$ -	$ -

$ -	$ -
$ -	$ -
-$ 196,759	$ 500,578
$ -	$ -
$ 863,069	-$ 3,594,055
$ -	-$ 0
$ -	$ -
-$ 31,589,256	**$ 59,327,584**

ovide data for the earlier of: 1) all

are classified under multiple CCA

CCA Class	OEB	Description	Depreciation Rate	Opening Balance
12	1611	Computer Software (Formally known as Account 1925)		$ 200,139
CEC	1612	Land Rights (Formally known as Account 1906)		$ 89,022
N/A	1805	Land		$ 181,961
CEC	1806	Land Rights		$ 5,968
47	1808	Buildings		$ 1,163,732
13	1810	Leasehold Improvements		$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,507,912
47	1820	Distribution Station Equipment <50 kV		$ 74,427
47	1825	Storage Battery Equipment		$ -
47	1830	Poles, Towers & Fixtures		$ 16,966,416
47	1835	Overhead Conductors & Devices		$ 12,550,744
47	1840	Underground Conduit		$ 13,858,533
47	1845	Underground Conductors & Devices		$ 18,593,842
47	1850	Line Transformers		$ 17,383,772
47	1855	Services (Overhead & Underground)		$ 1,563,785
47	1860	Meters		$ -
47	1860	Meters (Smart Meters)		$ -
N/A	1905	Land		$ -
47	1908	Buildings & Fixtures		$ -
13	1910	Leasehold Improvements		$ -
8	1915	Office Furniture & Equipment (10 years)		$ -
8	1915	Office Furniture & Equipment (5 years)		$ -
10	1920	Computer Equipment - Hardware		$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -
	1925	Computer Software		$ 435,329
10	1930	Transportation Equipment		$ 2,928,990
8	1935	Stores Equipment		$ -
8	1940	Tools, Shop & Garage Equipment		$ 143,992
8	1945	Measurement & Testing Equipment		$ -
8	1950	Power Operated Equipment		$ -
8	1955	Communications Equipment		$ -
8	1955	Communication Equipment (Smart Meters)		$ -
8	1960	Miscellaneous Equipment		$ -

47	1970	Load Management Controls - Customer Premises		$ -
47	1975	Load Management Controls Utility Premises		$ -
47	1980	System Supervisor Equipment		$ 697,337
47	1985	Miscellaneous Fixed Assets		$ -
47	1995	Contributions & Grants		-$ 4,457,124
N/A	2040	Plant Held for Future Use		-$ 0
	etc.			
		Total		**$ 86,888,776**

10		Transportation
8		Stores Equipment

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted f rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes ir applicant uses any different classes from those shown in the table, an explanation should b

3 The table may need to be customized for a utility's asset categories or for any new asset ac

4 The depreciation column (D) is not required as the relevant information will be provided in tl

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2013**

Cost					
Reallocate Smart Meters	Additions	Disposals	Closing Balance	Opening Balance	Reallocate Smart Meters
$ 1,963	$ 186,000	$ -	$ 388,102	-$ 326,271	-$ 647
$ -	$ -	$ -	$ 89,022	-$ 7,748	$ -
$ -	$ -	$ -	$ 181,961	$ -	$ -
$ -	$ -	$ -	$ 5,968	$ -	$ -
$ -	$ -	$ -	$ 1,163,732	-$ 194,532	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 4,507,912	-$ 893,531	$ -
$ -	$ -	$ -	$ 74,427	-$ 30,025	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ 200,025	$ -	$ 17,166,441	-$ 6,440,840	$ -
$ -	$ 952,900	$ -	$ 13,503,644	-$ 4,373,530	$ -
$ -	$ 22,300	$ -	$ 13,880,833	-$ 5,327,722	$ -
$ -	$ 989,200	$ -	$ 19,583,042	-$ 4,788,200	$ -
$ -	$ 452,900	$ -	$ 17,836,672	-$ 6,365,512	$ -
$ -	$ 97,400	$ -	$ 1,661,185	-$ 270,746	$ -
$ -	$ 181,160	$ -	$ 181,160	$ -	$ -
$ 5,329,835	$ -	$ -	$ 5,329,835	$ -	-$ 978,737
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ 41,939	$ 13,800	$ -	$ 55,739	$ -	-$ 28,940
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 435,329	$ -	$ -
$ -	$ 200,000	$ -	$ 3,128,990	-$ 2,132,692	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ 25,000	$ -	$ 168,992	-$ 73,675	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -

$ -	$ -	$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -		$ -	$ -
$ -	$ 50,000	$ -	$ 747,337		-$ 196,759	$ -
$ -	$ -	$ -	$ -		$ -	$ -
$ -	-$ 273,055	$ -	-$ 4,730,179		$ 863,069	$ -
$ -	$ -	$ -	-$ 0		$ -	$ -
			$ -			
			$ -			
$ 5,373,737	**$ 3,097,630**	**$ -**	**$ 95,360,143**		**-$ 30,558,713**	**-$ 1,008,324**

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation

or the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide
Year forecasts.

n Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are c
e provided. (also see note 3 below).

ccounts announced or authorized by the Board.

he following 2-C series of appendices.

File Number:	EB-2012-0109
Exhibit:	2
Tab:	
Schedule:	
Page:	7
Date:	July 17,2013

Accumulated Depreciation			
Additions	Disposals	Closing Balance	Net Book Value
-$ 112,129	$ -	-$ 439,047	-$ 50,945
-$ 1,780	$ -	-$ 9,528	$ 79,494
$ -	$ -	$ -	$ 181,961
$ -	$ -	$ -	$ 5,968
-$ 27,086	$ -	-$ 221,618	$ 942,114
$ -	$ -	$ -	$ -
-$ 104,104	$ -	-$ 997,635	$ 3,510,277
-$ 1,560	$ -	-$ 31,585	$ 42,842
$ -	$ -	$ -	$ -
-$ 390,465	$ -	-$ 6,831,305	$ 10,335,136
-$ 235,869	$ -	-$ 4,609,399	$ 8,894,245
-$ 235,277	$ -	-$ 5,562,999	$ 8,317,834
-$ 632,793	$ -	-$ 5,420,993	$ 14,162,049
-$ 438,147	$ -	-$ 6,803,659	$ 11,033,013
-$ 64,497	$ -	-$ 335,243	$ 1,325,942
-$ 423,759	$ -	-$ 423,759	-$ 242,599
-$ 355,322	$ -	-$ 1,334,059	$ 3,995,776
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
-$ 312	$ -	-$ 312	-$ 312
$ -	$ -	$ -	$ -
-$ 27,585	$ -	-$ 56,525	-$ 786
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 435,329
-$ 153,172	$ -	-$ 2,285,864	$ 843,126
$ -	$ -	$ -	$ -
-$ 15,651	$ -	-$ 89,326	$ 79,666
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
-$ 6,662	$ -	-$ 6,662	-$ 6,662
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -

$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
-$ 26,074	$ -	-$ 222,833	$ 524,504
$ -	$ -	$ -	$ -
$ 105,158	$ -	$ 968,227	-$ 3,761,952
$ -	$ -	$ -	-$ 0
		$ -	$ -
-$ 3,147,086	**$ -**	**-$ 34,714,123**	**$ 60,646,019**

$ 153,172
$ 2,993,914

data for the earlier of: 1) all historical years back to its last

classified under multiple CCA Classes for tax purposes. If an

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	8
Date:	

Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

Year 2011 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			$ -		$ -		0.00%	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0.00%	$ -		$ -
1805	Land			$ -		$ -		0.00%	$ -		$ -
1808	Buildings			$ -		$ -		0.00%	$ -		$ -
1810	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -		0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV			$ -		$ -		0.00%	$ -		$ -
1825	Storage Battery Equipment			$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures			$ -		$ -		0.00%	$ -		$ -
1835	Overhead Conductors & Devices			$ -		$ -		0.00%	$ -		$ -
1840	Underground Conduit			$ -		$ -		0.00%	$ -		$ -
1845	Underground Conductors & Devices			$ -		$ -		0.00%	$ -		$ -
1850	Line Transformers			$ -		$ -		0.00%	$ -		$ -
1855	Services (Overhead & Underground)			$ -		$ -		0.00%	$ -		$ -
1860	Meters			$ -		$ -		0.00%	$ -		$ -
1860	Meters (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1905	Land			$ -		$ -		0.00%	$ -		$ -
1908	Buildings & Fixtures			$ -		$ -		0.00%	$ -		$ -
1910	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment			$ -		$ -		0.00%	$ -		$ -
1935	Stores Equipment			$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			$ -		$ -		0.00%	$ -		$ -
1945	Measurement & Testing Equipment			$ -		$ -		0.00%	$ -		$ -
1950	Power Operated Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communications Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1960	Miscellaneous Equipment			$ -		$ -		0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -		0.00%	$ -		$ -
1980	System Supervisor Equipment			$ -		$ -		0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants			$ -		$ -		0.00%	$ -		$ -
etc.				$ -		$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	9
Date:	

Appendix 2-CB
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

Year **2011** **MIFRS**

Account	Description	Opening NBV as at Jan 1, 2011 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2011 Depreciation Expense (k) = (j) + (h)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2011 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2011 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1612	Land Rights (Formally known as Account 1906)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1835	Overhead Conductors & Devices					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1840	Underground Conduit					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1845	Underground Conductors & Devices					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1850	Line Transformers					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1855	Services (Overhead & Underground)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1860	Meters					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1905	Land					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1910	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1935	Stores Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1950	Power Operated Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communications Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributions & Grants					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ -	$ -				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
2 The applicant must provide an explanation of material variances in evidence
3 The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with IFRS.
4 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2011 additions) under IFRS. For example, Asset A had a useful life of 20 years under CGAAP. On January 1, 2011, the date of transition, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) under CGAAP as of January 1, 2011. Due to the transition to IFRS, management re-assessed the asset useful lives under IFRS principles and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of opening balance of Asset A is determined to be 27 years (30 years less 3 years) under IFRS as of January 1, 2011.
5 NBV must exclude assets still on the books but which have been fully amortized or depreciated.
6 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	10
Date:	

Appendix 2-CC
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2012 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2012 Depreciation Expense [1] (h)=2011 Full Year Deprecation + ((d)*0.5)/(f)	2012 Depreciation Expense per Apppendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [3] (o) = 2011 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ -		$ -	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land			0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ -		$ -	$ -		$ -
1835	Overhead Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1840	Underground Conduit			0.00%	$ -		$ -	$ -		$ -
1845	Underground Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1850	Line Transformers			0.00%	$ -		$ -	$ -		$ -
1855	Services (Overhead & Underground)			0.00%	$ -		$ -	$ -		$ -
1860	Meters			0.00%	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -	$ -		$ -
etc.				0.00%	$ -		$ -	$ -		$ -
				0.00%	$ -		$ -	$ -		$ -
	Total	$ -			$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

3 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	11
Date:	

Appendix 2-CD
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -
1805	Land			0.00%	$ -		$ -
1808	Buildings			0.00%	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ -		$ -
1835	Overhead Conductors & Devices			0.00%	$ -		$ -
1840	Underground Conduit			0.00%	$ -		$ -
1845	Underground Conductors & Devices			0.00%	$ -		$ -
1850	Line Transformers			0.00%	$ -		$ -
1855	Services (Overhead & Underground)			0.00%	$ -		$ -
1860	Meters			0.00%	$ -		$ -
1860	Meters (Smart Meters)			0.00%	$ -		$ -
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$ -			$ -	$ -	$ -
	Depreciation expense adjustment resulting from amortization of Account 1575				$ -		
	Total Depreciation expense to be included in the test year revenue requirement				**$ -**		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	12
Date:	July 17,2013

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2011 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 181,960.63		$ 181,960.63	$ -	$ 181,960.63			$ -	$ -	$ -
1806	Land Rights	$ 5,968.42			$ -					$ -	
1808	Buildings	$ 1,163,731.71		$ 1,163,731.71	$ -	$ 1,163,731.71	50.00	2.00%	$ 23,274.63	$ 23,274.00	$ 0.63
1810	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 4,469,541.30		$ 4,469,541.30	$ 38,370.27	$ 4,488,726.44	40.00	2.50%	$ 112,218.16	$ 112,708.27	-$ 490.11
1820	Distribution Station Equipment <50 kV	$ 74,426.57		$ 74,426.57	$ -	$ 74,426.57	30.00	3.33%	$ 2,480.89	$ 2,481.00	-$ 0.11
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 15,293,731.41		$ 15,293,731.41	$ 680,278.43	$ 15,633,870.63	25.00	4.00%	$ 625,354.83	$ 638,939.43	-$ 13,584.61
1835	Overhead Conductors & Devices	$ 11,460,981.29		$ 11,460,981.29	$ 655,233.47	$ 11,788,598.03	25.00	4.00%	$ 471,543.92	$ 484,656.47	-$ 13,112.55
1840	Underground Conduit	$ 12,599,180.64		$ 12,599,180.64	$ 686,868.63	$ 12,942,614.96	25.00	4.00%	$ 517,704.60	$ 531,436.63	-$ 13,732.03
1845	Underground Conductors & Devices	$ 16,270,666.20		$ 16,270,666.20	$ 1,145,510.10	$ 16,843,421.25	25.00	4.00%	$ 673,736.85	$ 696,655.10	-$ 22,918.25
1850	Line Transformers	$ 16,554,086.34		$ 16,554,086.34	$ 478,371.85	$ 16,793,272.27	25.00	4.00%	$ 671,730.89	$ 681,294.85	-$ 9,563.96
1855	Services (Overhead & Underground)	$ 1,077,422.88		$ 1,077,422.88	$ 191,940.74	$ 1,173,393.25	25.00	4.00%	$ 46,935.73	$ 50,765.74	-$ 3,830.01
1860	Meters	$ 8,733,121.28		$ 8,733,121.28	$ 411,891.78	$ 8,939,067.17	25.00	4.00%	$ 357,562.69	$ 629,086.32	-$ 271,523.63
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1905	Land	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1925	Computer Software	$ 196,386.06		$ 196,386.06	$ 238,942.91	$ 315,857.52	5.00	20.00%	$ 63,171.50	$ 87,063.91	-$ 23,892.41
1930	Transportation Equipment	$ 2,723,343.94	$ 705,917.00	$ 2,017,426.94	$ 309,767.00	$ 2,172,310.44	8.00	12.50%	$ 271,538.81	$ 271,416.00	$ 122.80
1935	Stores Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 193,313.02	$ 54,401.00	$ 138,912.02	$ 1,380.00	$ 139,602.02	10.00	10.00%	$ 13,960.20	$ 14,030.00	-$ 69.80
1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1955	Communications Equipment	$ 1,176.32	$ 1,176.32	$ -	$ -	$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1970	Load Management Controls - Customer Premises	$ 547,972.38	$ 547,972.38	$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 652,617.30		$ 652,617.30	$ 7,701.54	$ 656,468.07	15.00	6.67%	$ 43,764.54	$ 43,981.54	-$ 217.00
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,586,012.84		-$ 3,586,012.84	-$ 265,560.28	-$ 3,718,792.98	25.00	4.00%	-$ 148,751.72	-$ 154,073.28	$ 5,321.56
2040	Plant Held for Future Use	$ 51,815.84			$ 2,940.00	$ 1,470.00			$ -	$ -	$ -
2055	Work in Progress	$ 104,107.49			-$ 80,098.32	-$ 40,049.16			$ -	$ -	$ -
etc.				$ -	$ -	$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 88,769,538.18	$ 1,309,466.70	$ 87,298,179.73	$ 4,503,538.12	$ 89,549,948.79			$ 3,746,226.51	$ 4,113,715.98	-$ 367,489.47
		$ -			$ -					$ -	

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	13
Date:	July 17,2013

Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year **2012** **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 435,328.97		$ 435,328.97	$ 180,900.00	$ 525,778.97	5.00	20.00%	$ 105,155.79	$ 122,545.00	-$ 17,389.21
1612	Land Rights (Formally known as Account 1906)	$ 5,968.42		$ 5,968.42	$ 64,700.00	$ 38,318.42	50.00	2.00%	$ 766.37	$ 7,262.00	-$ 6,495.63
1805	Land	$ 181,960.63		$ 181,960.63	$ -	$ 181,960.63		0.00%	$ -	$ -	$ -
1806	Land Rights	$ -			$ -					$ -	
1808	Buildings	$ 1,163,731.71		$ 1,163,731.71	$ -	$ 1,163,731.71	50.00	2.00%	$ 23,274.63	$ 23,274.00	$ 0.63
1810	Leasehold Improvements	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 4,507,911.57		$ 4,507,911.57	$ -	$ 4,507,911.57	40.00	2.50%	$ 112,697.79	$ 112,698.00	-$ 0.21
1820	Distribution Station Equipment <50 kV	$ 74,426.57		$ 74,426.57	$ -	$ 74,426.57	30.00	3.33%	$ 2,480.89	$ 2,481.00	-$ 0.11
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 15,974,009.84		$ 15,974,009.84	$ 584,500.00	$ 16,266,259.84	25.00	4.00%	$ 650,650.39	$ 663,581.00	-$ 12,930.61
1835	Overhead Conductors & Devices	$ 12,116,214.76		$ 12,116,214.76	$ 959,300.00	$ 12,595,864.76	25.00	4.00%	$ 503,834.59	$ 522,660.00	-$ 18,825.41
1840	Underground Conduit	$ 13,286,049.27		$ 13,286,049.27	$ 519,300.00	$ 13,545,699.27	25.00	4.00%	$ 541,827.97	$ 552,655.00	-$ 10,827.03
1845	Underground Conductors & Devices	$ 17,416,176.30		$ 17,416,176.30	$ 1,876,200.00	$ 18,354,276.30	25.00	4.00%	$ 734,171.05	$ 772,213.00	-$ 38,041.95
1850	Line Transformers	$ 17,032,458.19		$ 17,032,458.19	$ 796,400.00	$ 17,430,658.19	25.00	4.00%	$ 697,226.33	$ 713,874.00	-$ 16,647.67
1855	Services (Overhead & Underground)	$ 1,269,363.62		$ 1,269,363.62	$ 135,200.00	$ 1,336,963.62	25.00	4.00%	$ 53,478.54	$ 55,543.00	-$ 2,064.46
1860	Meters	$ 9,145,013.06		$ 9,145,013.06	$ 274,471.00	$ 9,282,248.56	25.00	4.00%	$ 371,289.94	$ 378,890.00	-$ 7,600.06
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1905	Land	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -		$ -	$ 5,000.00	$ 2,500.00	10.00	10.00%	$ 250.00	$ 500.00	-$ 250.00
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -		$ -	$ 1,000.00	$ 500.00	4.00	25.00%	$ 125.00	$ 200.00	-$ 75.00
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1925	Computer Software	$ -			$ -					$ -	
1930	Transportation Equipment	$ 3,033,110.94	$ 1,300,989.00	$ 1,732,121.94	$ 325,000.00	$ 1,894,621.94	8.00	12.50%	$ 236,827.74	$ 203,065.00	$ 33,762.74
1935	Stores Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 140,292.16		$ 140,292.16	$ 25,000.00	$ 152,792.16	10.00	10.00%	$ 15,279.22	$ 14,030.00	$ 1,249.22
1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1970	Load Management Controls - Customer Premises	$ -			$ -					$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 660,318.84		$ 660,318.84	$ 83,000.00	$ 701,818.84	15.00	6.67%	$ 46,787.92	$ 48,869.00	-$ 2,081.08
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,851,573.12		-$ 3,851,573.12	-$ 623,500.00	-$ 4,163,323.12	25.00	4.00%	-$ 166,532.92	-$ 154,072.28	-$ 12,460.64
2040	Plant Held for Future Use	$ 54,755.84			$ -					$ -	
2055	Work in Progress	$ 24,009.17			$ -					$ -	
					$ -						
etc.				$ -	$ -	$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ 92,669,526.74	$ 1,300,989.00	$ 91,289,772.73	$ 5,206,471.00	$ 93,893,008.23			$ 3,929,591.25	$ 4,040,267.72	-$ 110,676.47
		$ -			$ -						

Notes:

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	14
Date:	July 17,2013

Used this tab for the 2013 "MIFRS" Depreciation calculation
2013 is reported under CGAAP but BPI is aligning useful lives and componentization with MIFRS

Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 296,469.00	$ 310,000.00	5.00	5.00	20.00%	$ 59,293.80	$ 31,000.00	$ 90,293.80	$ 121,073.62	-$ 30,779.82	$ 62,000.00		$ 121,293.80
1612	Land Rights (Formally known as Account 1906)	$ 63,406.42	$ -	50.00	50.00	2.00%	$ 1,268.13	$ -	$ 1,268.13	$ 1,294.00	-$ 25.87	$ -		$ 1,268.13
1805	Land	$ 181,960.63	$ -		-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1806	Land Rights	$ -	$ -		-					$ -	$ -	$ -		
1808	Buildings	$ 969,199.81	$ -	36.64		0.00%	$ 26,451.96	$ -	$ 26,451.96	$ 27,086.00	-$ 634.04	$ -		$ 26,451.96
1810	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 3,614,381.00	$ -	33.32		0.00%	$ 108,474.82	$ -	$ 108,474.82	$ 104,104.00	$ 4,370.82	$ -		$ 108,474.82
1820	Distribution Station Equipment <50 kV	$ 44,402.06	$ -	9.63		0.00%	$ 4,610.81	$ -	$ 4,610.81	$ 1,560.00	$ 3,050.81	$ -		$ 4,610.81
1825	Storage Battery Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 10,132,752.00	$ 215,000.00			0.00%	$ -	$ -	$ -	$ 374,253.00	-$ 374,253.00	$ -		$ -
1835	Overhead Conductors & Devices	$ 8,684,530.00	$ 958,000.00			0.00%	$ -	$ -	$ -	$ 243,122.00	-$ 243,122.00	$ -		$ -
1840	Underground Conduit	$ 8,479,323.00	$ 35,000.00			0.00%	$ -	$ -	$ -	$ 233,392.00	-$ 233,392.00	$ -		$ -
1845	Underground Conductors & Devices	$ 14,475,705.60	$ 856,100.00			0.00%	$ -	$ -	$ -	$ 640,974.00	-$ 640,974.00	$ -		$ -
1850	Line Transformers	$ 11,444,812.00	$ 502,000.00			0.00%	$ -	$ -	$ -	$ 447,040.00	-$ 447,040.00	$ -		$ -
1855	Services (Overhead & Underground)	$ 1,140,823.00	$ 110,000.00			0.00%	$ -	$ -	$ -	$ 56,061.00	-$ 56,061.00	$ -		$ -
1860	Meters	$ 8,086,389.33	$ 205,000.00			0.00%	$ -	$ -	$ -	$ 783,165.38	-$ 783,165.38	$ -		$ -
1860	Meters (Smart Meters)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1905	Land	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 4,500.00	$ -			0.00%	$ -	$ -	$ -	$ 500.00	-$ 500.00	$ -		$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 42,739.00	$ 77,500.00			0.00%	$ -	$ -	$ -	$ 18,325.73	-$ 18,325.73	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1925	Computer Software	$ -	$ -			0.00%	$ -	$ -		$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,012,938.00	$ 200,000.00			0.00%	$ -	$ -	$ -	$ 161,947.00	-$ 161,947.00	$ -		$ -
1935	Stores Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 91,987.00	$ 25,000.00			0.00%	$ -	$ -	$ -	$ 17,781.00	-$ 17,781.00	$ -		$ -
1945	Measurement & Testing Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1950	Power Operated Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls - Customer Premises	$ -	$ -			0.00%	$ -	$ -		$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 544,225.71	$ 150,000.00			0.00%	$ -	$ -	$ -	$ 31,605.00	-$ 31,605.00	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 3,636,217.72	-$ 203,440.00			0.00%	$ -	$ -	$ -	-$ 105,753.00	$ 105,753.00	$ -		$ -
2040	Plant Held for Future Use	-$ 0.16	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
2055	Work in Progress	$ 24,009.17	$ -			0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ 65,698,334.85	$ 3,440,160.00				$ 200,099.51	$ 31,000.00	$ 231,099.51	$ 3,157,530.74	-$ 2,926,431.22	$ 62,000.00	$ -	$ 262,099.51
		$ -	$ -							$ -				

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

3 The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with IFRS.

4 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2012 additions) under IFRS. For example, Asset A had a useful life of 20 years under CGAAP. On January 1, 2012, the date of transition, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) under CGAAP as of January 1, 2012. Due to the transition to IFRS, management re-assessed the asset useful lives under IFRS principles and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of opening balance of Asset A is determined to be 27 years (30 years less 3 years) under IFRS as of January 1, 2012.

5 NBV must exclude assets still on the books but which have been fully amortized or depreciated.

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	15
Date:	July 17,2013

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ 121,293.80		$ 121,293.80
1612	Land Rights (Formally known as Account 1906)			0.00%	$ 1,268.13		$ 1,268.13
1805	Land			0.00%	$ -		$ -
1808	Buildings			0.00%	$ 26,451.96		$ 26,451.96
1810	Leasehold Improvements			0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ 108,474.82		$ 108,474.82
1820	Distribution Station Equipment <50 kV			0.00%	$ 4,610.81		$ 4,610.81
1825	Storage Battery Equipment			0.00%	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ -		$ -
1835	Overhead Conductors & Devices			0.00%	$ -		$ -
1840	Underground Conduit			0.00%	$ -		$ -
1845	Underground Conductors & Devices			0.00%	$ -		$ -
1850	Line Transformers			0.00%	$ -		$ -
1855	Services (Overhead & Underground)			0.00%	$ -		$ -
1860	Meters			0.00%	$ -		$ -
1860	Meters (Smart Meters)			0.00%	$ -		$ -
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	$ -			$ 262,099.51	$ -	$ 262,099.51
	Depreciation expense adjustment resulting from amortization of Account 1575				$ -		
	Total Depreciation expense to be included in the test year revenue requirement				**$ 262,099.51**		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	16
Date:	

Appendix 2-CI
Depreciation and Amortization Expense

Assumes the applicant adopted an alternate accounting standard other than IFRS for financial reporting purposes. For applicants adopting an Alternate Accounting Standard for financial reporting purposes January 1, 2012, applicants must complete 4 versions of the table below (2011 CGAAP, 2011 Alternate Accounting Standard, 2012 Alternate Accounting Standard and 2013 Alternate Accounting Standard). For applicants adopting an Alternate Accounting Standard for financial reporting purposes January 1, 2013, applicants must complete 4 versions of the table below (2011 CGAAP, 2012 CGAAP, 2012 Alternate Accounting Standard and 2013 Alternate Accounting Standard).

Year ______ **Accounting Standard** ______

Account	Description	Opening Regulatory Gross PP&E (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			$ -		$ -		0.00%	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0.00%	$ -		$ -
1805	Land			$ -		$ -		0.00%	$ -		$ -
1808	Buildings			$ -		$ -		0.00%	$ -		$ -
1810	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -		0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV			$ -		$ -		0.00%	$ -		$ -
1825	Storage Battery Equipment			$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures			$ -		$ -		0.00%	$ -		$ -
1835	Overhead Conductors & Devices			$ -		$ -		0.00%	$ -		$ -
1840	Underground Conduit			$ -		$ -		0.00%	$ -		$ -
1845	Underground Conductors & Devices			$ -		$ -		0.00%	$ -		$ -
1850	Line Transformers			$ -		$ -		0.00%	$ -		$ -
1855	Services (Overhead & Underground)			$ -		$ -		0.00%	$ -		$ -
1860	Meters			$ -		$ -		0.00%	$ -		$ -
1860	Meters (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1905	Land			$ -		$ -		0.00%	$ -		$ -
1908	Buildings & Fixtures			$ -		$ -		0.00%	$ -		$ -
1910	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment			$ -		$ -		0.00%	$ -		$ -
1935	Stores Equipment			$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			$ -		$ -		0.00%	$ -		$ -
1945	Measurement & Testing Equipment			$ -		$ -		0.00%	$ -		$ -
1950	Power Operated Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communications Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1960	Miscellaneous Equipment			$ -		$ -		0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -		0.00%	$ -		$ -
1980	System Supervisor Equipment			$ -		$ -		0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants			$ -		$ -		0.00%	$ -		$ -
etc.				$ -		$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2012-0109
Exhibit:	2,4
Tab:	
Schedule:	
Page:	
Date:	July 17,2013

Appendix 2-D
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS or an alternate accounting

Nature of the Overhead Costs	(A) [1] Dollar Impact on PP&E Historic Year	(B) Dollar Impact on PP&E Bridge Year	(C) Dollar Impact on PP&E Test Year	(D) Dollar Impact - PP&E Variance Test versus Bridge	(E) [1] Dollar Impact - PP&E Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				$ -	$ -		
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		
administration and other general overhead costs				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ -	$ -	$ -		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

Nature of the Overhead Costs	(A) [1] Dollar Impact on OM&A Historic Year	(B) Dollar Impact on OM&A Bridge Year	(C) Dollar Impact on OM&A Test Year	(D) Dollar Impact - OM&A Variance Test versus Bridge	(E) [1] Dollar Impact - OM&A Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				$ -	$ -		
costs of site preparation				$ -	$ -		
initial delivery and handling costs (STORES - 22% markup on inventory)	$ 255,114	$ 233,994		-$ 233,994	-$ 255,114		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising and promotional				$ -	$ -		
costs of conducting business in a new location or with a new class of customer (including costs of				$ -	$ -		
administration and other general overhead costs	$ 333,433	$ 210,540		-$ 210,540	-$ 333,433		
percentage allocation of senior management salaries, benefits and related expenses	$ 573,586	$ 542,466		-$ 542,466	-$ 573,586		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 1,162,133	$ 987,000	$ -	-$ 987,000	-$ 1,162,133		

Notes:

1 If the applicant chooses to adopt IFRS or an alternate accounting standard for financial reporting purposes in 2013, the applicant does not need to complete Columns A, E. If the applicant adopts IFRS or an alternate accounting standard for financial reporting purposes in 2012, the applicant must complete all columns.

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	17
Date:	

Appendix 2-EA
IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	**CGAAP**	**IRM**	**IRM**	**IRM**	**MIFRS**	**IRM**	**IRM**	**IRM**
Forecast vs. Actual Used in Rebasing Year	**Forecast**	**Actual**	**Actual**	**Forecast**	**Forecast**			
			$	$				
PP&E Values under CGAAP								
Opening net PP&E - Note 1								
Additions								
Depreciation (amounts should be negative)								
Closing net PP&E (1)			0	0				
PP&E Values under MIFRS (Starts from 2011, the transition year)								
Opening net PP&E - Note 1								
Additions								
Depreciation (amounts should be negative)								
Closing net PP&E (2)			0	0				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)			0	0				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance			0	0	0	0	0	0
Amounts added in the year			0	0				
Sub-total			0	0	0	0	0	0
Amount of amortization, included in depreciation expense - Note 2					0	0	0	0
Closing balance in deferral account			0	0	0	0	0	0

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	0
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	0
Amount included in Revenue Requirement on rebasing	0

WACC		
Disposition Period - Note 4	**4**	Years

Notes:

1 For an applicant that adopts IFRS on January 1, 2012, the PP&E values as of January 1, 2011 under both CGAAP and MIFRS should be the same.

2 Amortization of the deferred balance in Account 1575 will start from the rebasing year.
Assume the utility requests for a certain disposition period, the amortization that should be included in the depreciation expense is calculated as:
the opening balance of Account 1575 / the approved disposition period

3 Return on rate base associated with deferred balance is calculated as:
the deferred account opening balance as of 2013 rebasing year x WACC
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

4 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to ratebase to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	18
Date:	

Appendix 2-EB
IFRS-CGAAP Transitional PP&E Amounts
2013 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2013 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2013.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$
PP&E Values under CGAAP								
Opening net PP&E - Note 1								
Additions								
Depreciation (amounts should be negative)								
Closing net PP&E (1)				0				
PP&E Values under MIFRS (Starts from 2012, the transition year)								
Opening net PP&E - Note 1								
Additions								
Depreciation (amounts should be negative)								
Closing net PP&E (2)				0				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)				0				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance				0	0	0	0	0
Amounts added in the year				0				
Sub-total				0	0	0	0	0
Amount of amortization, included in depreciation expense - Note 2					0	0	0	0
Closing balance in deferral account				0	0	0	0	0

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	0
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	0
Amount included in Revenue Requirement on rebasing	0

WACC		
Disposition Period - Note 4	**4**	Years

Notes:

1 For an applicant that adopts IFRS on January 1, 2013, the PP&E values as of January 1, 2012 under both CGAAP and MIFRS should be the same.

2 Amortization of the deferred balance in Account 1575 will start from the rebasing year.
Assume the utility requests for a certain disposition period, the amortization that should be included in the depreciation expense is calculated as:
the opening balance of Account 1575 / the approved disposition period

3 Return on rate base associated with deferred balance is calculated as:
the deferred account opening balance as of 2013 rebasing year x WACC
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

4 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to ratebase to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

File Number:	EB-2012-0109
Exhibit:	Interrogatory Responses
Tab:	
Schedule:	
Page:	
Date:	July 17,2013
Revised	October 23 2013

Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	2012 Actual
						2012	2013	
	Reporting Basis						CGAAP	
4235	Misc. Service Revenue	$ 589,631	$ 575,804	$ 635,867	$ 469,500	$ 403,588	$ 422,134	$ 407,627.62
4225	Late Payment Charges	$ 108,433	$ 99,278	$ 7,651	$ 111,988	$ 122,798	$ 120,000	$ 124,194.23
4082	Retailer Services Revenue	$ 74,089	$ 80,804	$ 66,001	$ 53,469	$ 31,557	$ 38,639	$ 32,677.24
4080	SSS Admin Fees	$ 93,320	$ 93,675	$ 96,005	$ 99,725	$ 103,910	$ 104,830	$ 103,915.15
4084	Serv Trans by REQ (STR)	$ 26,850	$ 19,258	$ 17,861	$ 14,821	$ 18,441	$ 11,660	$ 18,549.67
4210	Rent from Electric Property	$ 96,294	$ 121,418	$ 103,842	$ 104,422	$ 106,000	$ 108,120	$ 105,560.39
4215	Other Utility Operating Inc	$ -	$ -	$ -	$ -	$ -	$ -	
4220	Other Electric Revenue	$ 2,833	$ 566	$ 1,088	$ 189	$ -	$ -	
4240	Provision for Rate Refunds	$ -	$ -	$ -	$ -	$ -	$ -	
4335	P&L from FI Hedges	$ -	$ -	$ -	$ -	$ -	$ -	
4355	Gain on Disposition of Utility and Other Property	$ 4,550	-$ 22,969	$ 51,067	$ 19,025	$ -	$ -	$ 565.00
4360	Loss on Disposal of Property	$ -	$ -	$ -	$ -	$ -	$ -	
4375	Revenue from Non-Utility Operations	$ 541,188	$ 2,189,506	$ 1,130,495	$ 723,014	$ 3,897,395	$ 5,165,361	$ 4,020,507.67
4380	Expenses from Non-Utility Operations	-$ 482,836	-$ 1,846,309	-$ 926,976	-$ 735,093	-$ 3,897,395	-$ 5,165,361	-$ 3,683,840.23
4390	Misc. Non-Operating Income	$ 70,259	$ 35,377	$ 37,989	$ 28,525	$ 12,800	$ 20,000	$ 16,350.11
4405	Interest & Dividend Income	$ 385,736	$ 128,823	$ 129,666	$ 278,195	$ 271,024	$ 275,539	$ 273,775.01
Specific Service Charges		$ 589,631	$ 575,804	$ 635,867	$ 469,500	$ 403,588	$ 422,134	$ 407,627.62
Late Payment Charges		$ 108,433	$ 99,278	$ 7,651	$ 111,988	$ 122,798	$ 120,000	$ 124,194.23
Other Operating Revenues		$ 293,386	$ 315,719	$ 284,797	$ 272,626	$ 259,908	$ 263,249	$ 261,267.45
Other Income or Deductions		$ 518,897	$ 484,428	$ 422,240	$ 313,666	$ 283,824	$ 295,539	$ 626,792.56
Total*		$ 1,510,346	$ 1,475,230	$ 1,350,554	$ 1,167,779	$ 1,070,118	$ 1,100,922	$ 1,419,881.86

* Please note- For 2013 Test, revenues from Standby rates have also been included as a revenue offset. Total other revenues including Standby revenues of $60 224 total $1 161 146

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

The above table assumes adoption of MIFRS as of January 1, 2013. If the adoption year differs, please adjust the table accordingly.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4210- Rent from Electric Property

	2008 Actual	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Actual
Reporting Basis					2012	2013	2012

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-G
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account Description	Last Rebasing Year (2008 Actuals)	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	2012 Actual	Test Year 2013
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Operations							
5005 Operation Supervision and Engineering	$ 311,749	$ 332,926	$ 335,123	$ 327,414	$ 226,223	$ 387,915	$ 273,250
5010 Load Dispatching	$ 38,989	$ 35,700	$ 49,739	$ 31,918	$ 45,927	$ 43,685	$ 114,745
5012 Station Buildings and Fixtures Expense	$ 40,428	$ 33,982	$ 29,812	$ 25,755	$ 29,252	$ 25,449	$ 29,322
5014 Transformer Station Equipment - Operation Labour	$ 6,002	$ 5,596	$ 7,009	$ 15,354	$ 7,906	$ 6,611	$ 24,787
5015 Transformer Station Equipment - Operation Supplies and Expenses	$ 77,928	$ 67,308	$ 72,587	$ 96,171	$ 75,365	$ 79,709	$ 102,609
5016 Distribution Station Equipment - Operation Labour	$ 2,481	$ 2,387	$ 1,277	$ 4,208	$ 1,743	$ 1,260	$ 1,962
5017 Distribution Station Equipment - Operation Supplies and Expenses	$ 3,421	$ 1,512	$ 1,134	$ 1,155	$ 400	$ 357	$ 520
5020 Overhead Distribution Lines and Feeders - Operation Labour	$ 1,222	$ 2,523	$ 1,771	$ 1,928	$ 985	$ -	$ 1,962
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 720	$ 6,293	$ 6,026	$ 1,976	$ 10,893	$ 11,333	$ 12,752
5030 Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5035 Overhead Distribution Transformers - Operation	$ 1,044	$ 8,986	$ 9,393	$ 3,868	$ 2,989	$ 907	$ 5,154
5040 Underground Distribution Lines and Feeders - Operation Labour	$ 1,137	$ 139	$ 1,671	$ 1,178	$ 670	$ 27	$ -
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 11,204	$ 5,625	$ 10,635	$ 6,267	$ 9,508	$ 10,661	$ 11,990
5050 Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5055 Underground Distribution Transformers - Operation	$ 1,830	$ 1,387	$ 1,736	$ 685	$ 665	$ 52	$ -
5060 Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5065 Meter Expense	$ 305,437	$ 285,758	$ 265,762	$ 363,773	$ 464,155	$ 548,618	$ 593,094
5070 Customer Premises - Operation Labour	$ 897	$ 315	$ 334	$ 461	$ 710	$ 430	$ 5,292
5075 Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5085 Miscellaneous Distribution Expenses	$ 214,419	$ 253,078	$ 186,167	$ 182,823	$ 221,832	$ 182,710	$ 329,209
5090 Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5095 Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ 13,596	$ 19,983	$ 6,869	$ 7,343	$ 6,711	$ 25,403
5096 Other Rent	$ -	$ -	$ 8,233	$ 4,540	$ 4,732	$ 15,862	$ 44,455
Total - Operations	$ 1,018,908	$ 1,057,112	$ 1,008,391	$ 1,076,343	$ 1,111,298	$ 1,322,296	$ 1,576,506
Account Description	**Last Rebasing Year (2008 Actuals)**		**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**2012 Actual**	**Test Year 2013**
Maintenance							
5105 Maintenance Supervision and Engineering	$ 301,446	$ 304,849	$ 325,801	$ 307,486	$ 432,478	$ 204,823	$ 499,599
5110 Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ 431	$ 1,031	$ 1,892	$ 1,559	$ 930	$ 2,158
5112 Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5114 Maintenance of Distribution Station Equipment	$ 7,164	$ 9,409	$ 10,704	$ 5,684	$ 6,747	$ 1,203	$ 9,805
5120 Maintenance of Poles, Towers and Fixtures	$ 182,780	$ 135,624	$ 57,113	$ 44,139	$ 32,442	$ 59,222	$ 75,414
5125 Maintenance of Overhead Conductors and Devices	$ 116,671	$ 128,912	$ 109,023	$ 196,827	$ 184,573	$ 157,869	$ 242,022
5130 Maintenance of Overhead Services	$ 230,266	$ 200,498	$ 229,757	$ 218,602	$ 192,135	$ 162,683	$ 247,604
5135 Overhead Distribution Lines and Feeders - Right of Way	$ 443,359	$ 399,183	$ 396,203	$ 348,542	$ 415,898	$ 391,195	$ 499,535
5145 Maintenance of Underground Conduit	$ 43,295	$ 75,395	$ 38,898	$ 54,614	$ 52,661	$ 55,273	$ 56,902
5150 Maintenance of Underground Conductors and Devices	$ 78,960	$ 138,560	$ 89,626	$ 71,835	$ 70,158	$ 49,277	$ 82,311
5155 Maintenance of Underground Services	$ 210,769	$ 221,815	$ 143,095	$ 138,372	$ 109,059	$ 109,014	$ 124,877
5160 Maintenance of Line Transformers	$ 142,265	$ 108,654	$ 279,921	$ 68,591	$ 305,006	$ 236,456	$ 192,863
5165 Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5170 Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5172 Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5175 Maintenance of Meters	$ 171	$ 26	$ -	$ -	$ 153	$ 141	$ -
5178 Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5195 Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total - Maintenance	$ 1,757,147	$ 1,723,356	$ 1,681,173	$ 1,456,583	$ 1,802,869	$ 1,428,085	$ 2,033,090
Account Description	**Last Rebasing Year (2008 Actuals)**		**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**2012 Actual**	**Test Year 2013**
Billing and Collecting							
5305 Supervision	$ 167,397	$ 175,292	$ 181,121	$ 161,326	$ 223,136	$ 258,214	$ 292,372
5310 Meter Reading Expense	$ 409,719	$ 440,325	$ 402,412	$ 354,422	$ 274,993	$ 408,268	$ 240,556
5315 Customer Billing	$ 517,916	$ 542,936	$ 555,894	$ 495,101	$ 542,425	$ 586,654	$ 964,616
5320 Collecting	$ 334,793	$ 350,585	$ 362,242	$ 322,653	$ 359,916	$ 305,480	$ 536,496
5325 Collecting - Cash Over and Short	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5330 Collection Charges	$ 282	$ 548	$ 454	$ 833	$ 1,000	$ 12,413	$ 500
5335 Bad Debt Expense	$ 130,318	$ 257,772	$ 211,527	$ 307,532	$ 300,000	$ 163,887	$ 306,000
5340 Miscellaneous Customer Accounts Expenses	$ 418,492	$ 438,231	$ 452,803	$ 403,316	$ 506,862	$ 560,922	$ 522,675
Total - Billing and Collecting	$ 1,978,917	$ 2,205,690	$ 2,166,453	$ 2,045,182	$ 2,208,332	$ 2,295,837	$ 2,863,215
Account Description	**Last Rebasing Year (2008 Actuals)**		**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**2012 Actual**	**Test Year 2013**
Community Relations							
5405 Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5410 Community Relations - Sundry	$ 106,288	$ 119,559	$ 113,351	$ 106,211	$ 156,330	$ 148,571	$ 152,526
5415 Energy Conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5420 Community Safety Program	$ 6,949	$ 8,270	$ 18,029	$ 9,412	$ 12,807	$ 12,068	$ 19,051
5425 Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,200
5505 Supervision	$ -	$ -	$ -	$ -	$ -		$ -
5510 Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -		$ -

5515 Advertising Expenses	$ -	$ -	$ -	$ -	$ -		$ -
5520 Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -		$ -
Total - Community Relations	$ 113,237	$ 127,829	$ 131,379	$ 115,623	$ 169,137	$ 160,639	$ 232,777
Account Description	**Last Rebasing Year (2008 Actuals)**		**2010 Actual**	**2011 Actual[2]**	**Bridge Year 2012[3]**	**2012 Actual**	**Test Year 2013**
Administrative and General Expenses							
5605 Executive Salaries and Expenses	$ 424,360	$ 388,053	$ 403,908	$ 319,673	$ 533,369	$ 540,492	$ 729,401
5610 Management Salaries and Expenses	$ 370,449	$ 397,061	$ 402,930	$ 302,363	$ 340,676	$ 253,135	$ 384,158
5615 General Administrative Salaries and Expenses	$ 909,393	$ 867,658	$ 917,874	$ 884,744	$ 875,651	$ 949,117	$ 582,990
5620 Office Supplies and Expenses	$ 65,707	$ 65,075	$ 57,260	$ 51,082	$ 58,468	$ 61,555	$ 80,250
5625 Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5630 Outside Services Employed	$ 110,786	$ 39,291	$ 58,600	$ 127,715	$ 138,735	$ 100,792	$ 220,000
5635 Property Insurance	$ 151,793	$ 99,320	$ 74,245	$ 99,678	$ 100,861	$ 100,723	$ 133,133
5640 Injuries and Damages	$ 12,642	$ -	$ -	$ -	$ -	$ -	$ -
5645 OMERS Pensions and Benefits	$ 220,062	$ 244,532	$ 215,393	$ 175,099	$ 302,000	$ 433,800	$ 108,000
5646 Employee Pensions and OPEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5647 Employee Sick Leave	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5650 Franchise Requirements	$ 50,130	$ 50,606	$ 53,427	$ 53,775	$ 57,569	$ 57,569	$ 59,000
5655 Regulatory Expenses	$ 248,012	$ 284,560	$ 184,346	$ 120,735	$ 135,500	$ 125,787	$ 144,500
5660 General Advertising Expenses	$ 27,062	$ 20,789	$ 27,398	$ 15,894	$ 13,600	$ 29,123	$ 40,000
5665 Miscellaneous General Expenses	$ 184,695	$ 119,196	$ 84,705	$ 151,291	$ 8,341	$ 168,325	-$ 1,995
5670 Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5672 Lease Payment Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5675 Maintenance of General Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5680 Electrical Safety Authority Fees	$ 15,642	$ 16,129	$ 16,167	$ 16,013	$ 16,400	$ 16,305	$ 19,000
5681 Special Purpose Charge Expense	$ -	$ -	$ 376,534	$ -	$ -	$ -	$ -
5685 Independent Electricity System Operator Fees and Penalties	$ 54,425	$ 51,566	$ 51,566	$ 51,758	$ 60,000	$ 56,177	$ -
5695 OM&A Contra Account	-$ 19,371	-$ 29,756	$ 46,971	-$ 51,215	-$ 120,132	-$ 193,257	$ -
6205 Donations					$ -	$ -	
6205 Donations, Sub-account LEAP Funding	$ -	$ -	$ -	$ -		$ -	
Total - Administrative and General Expenses	$ 2,825,788	$ 2,614,082	$ 2,971,323	$ 2,318,604	$ 2,521,038	$ 2,699,643	$ 2,498,437
Total OM&A	$ 7,693,996	$ 7,728,069	$ 7,958,720	$ 7,012,336	$ 7,812,674	$ 7,906,500	$ 9,204,025
Adjustments for non-recoverable items							
5681 Special Purpose Charge Expense	$ -	$ -	$ 376,534	$ -		$ -	
6205 Donations[1]						$ -	
Total Recoverable OM&A	$ 7,693,996	$ 7,728,069	$ 7,582,186	$ 7,012,336	$ 7,812,674	$ 7,906,500	$ 9,204,025

[1] Account 6205 - Donations is generally non-recoverable. However, the sub-account LEAP funding of account 6205 is generally recoverable.

Note:

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

2 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, 2011 must be presented on both a CGAAP and MIFRS (or alternate accoun basis.

3 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, 2012 must be presented on both a CGAAP and MIFRS (or alternate accoun basis.

Appendix 2-H
OM&A Detailed Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	Last Board-approved Rebasing Year (2008 Year)	2008 Actual	Most Current Actuals Year 2011	Test Year 2013	2008 Board Approved Versus 2008 Actual		Test Year V Reba
						Variance ($)	Percentage	Variance ($)
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP			
Operations								
5005	Operation Supervision and Engineering	$ 244,352	$ 311,749	$ 327,414	$ 273,250	$ 67,397	28%	$ 28,898
5010	Load Dispatching	$ 16,375	$ 38,989	$ 31,918	$ 114,745	$ 22,614	138%	$ 98,370
5012	Station Buildings and Fixtures Expense	$ 36,464	$ 40,428	$ 25,755	$ 29,322	$ 3,964	11%	-$ 7,142
5014	Transformer Station Equipment - Operation Labour	$ 6,205	$ 6,002	$ 15,354	$ 24,787	-$ 203	-3%	$ 18,582
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 51,220	$ 77,928	$ 96,171	$ 102,609	$ 26,708	52%	$ 51,389
5016	Distribution Station Equipment - Operation Labour	$ 1,959	$ 2,481	$ 4,208	$ 1,962	$ 522	27%	$ 3
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 3,612	$ 3,421	$ 1,155	$ 520	-$ 191	-5%	-$ 3,092
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 3,019	$ 1,222	$ 1,928	$ 1,962	-$ 1,797	-60%	-$ 1,057
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 13,806	$ 720	$ 1,976	$ 12,752	-$ 13,086	-95%	-$ 1,054
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -		$ -
5035	Overhead Distribution Transformers - Operation	$ 14,800	$ 1,044	$ 3,868	$ 5,154	-$ 13,756	-93%	-$ 9,646
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 1,043	$ 1,137	$ 1,178	$ -	$ 94	9%	-$ 1,043
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 18,921	$ 11,204	$ 6,267	$ 11,990	-$ 7,717	-41%	-$ 6,931
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -		$ -
5055	Underground Distribution Transformers - Operation	$ 3,290	$ 1,830	$ 685	$ -	-$ 1,460	-44%	-$ 3,290
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -		$ -
5065	Meter Expense	$ 452,578	$ 305,437	$ 363,773	$ 593,094	-$ 147,141	-33%	$ 140,516
5070	Customer Premises - Operation Labour	$ 5,979	$ 897	$ 461	$ 5,292	-$ 5,082	-85%	-$ 687
5075	Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -	$ -		$ -
5085	Miscellaneous Distribution Expenses	$ 118,312	$ 214,419	$ 182,823	$ 329,209	$ 96,107	81%	$ 210,897
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -		$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 6,285	$ -	$ 6,869	$ 25,403	-$ 6,285	-100%	$ 19,118
5096	Other Rent	$ -	$ -	$ 4,540	$ 44,455	$ -		$ 44,455
Total - Operations		$ 998,220	$ 1,018,908	$ 1,076,343	$ 1,576,506	$ 20,688	2%	$ 578,286
Account	**Description**							
Maintenance								
5105	Maintenance Supervision and Engineering	$ 280,966	$ 301,446	$ 307,486	$ 499,599	$ 20,480	7%	$ 218,633
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 3,970	$ -	$ 1,892	$ 2,158	-$ 3,970	-100%	-$ 1,812
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -		$ -
5114	Maintenance of Distribution Station Equipment	$ 16,206	$ 7,164	$ 5,684	$ 9,805	-$ 9,042	-56%	-$ 6,401
5120	Maintenance of Poles, Towers and Fixtures	$ 153,188	$ 182,780	$ 44,139	$ 75,414	$ 29,592	19%	-$ 77,774
5125	Maintenance of Overhead Conductors and Devices	$ 194,468	$ 116,671	$ 196,827	$ 242,022	-$ 77,797	-40%	$ 47,554
5130	Maintenance of Overhead Services	$ 201,225	$ 230,266	$ 218,602	$ 247,604	$ 29,041	14%	$ 46,379
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 333,592	$ 443,359	$ 348,542	$ 499,535	$ 109,767	33%	$ 165,943
5145	Maintenance of Underground Conduit	$ 66,733	$ 43,295	$ 54,614	$ 56,902	-$ 23,438	-35%	-$ 9,831
5150	Maintenance of Underground Conductors and Devices	$ 111,669	$ 78,960	$ 71,835	$ 82,311	-$ 32,709	-29%	-$ 29,358
5155	Maintenance of Underground Services	$ 204,053	$ 210,769	$ 138,372	$ 124,877	$ 6,716	3%	-$ 79,176
5160	Maintenance of Line Transformers	$ 159,264	$ 142,265	$ 68,591	$ 192,863	-$ 16,999	-11%	$ 33,599
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -		$ -
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -		$ -
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -		$ -
5175	Maintenance of Meters	$ -	$ 171	$ -	$ -	$ 171		$ -
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -		$ -
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -		$ -
Total - Maintenance		$ 1,725,334	$ 1,757,147	$ 1,456,583	$ 2,033,090	$ 31,813	2%	$ 307,756
Account	**Description**							
Billing and Collecting								
5305	Supervision	$ 135,049	$ 167,397	$ 161,326	$ 292,372	$ 32,348	24%	$ 157,323
5310	Meter Reading Expense	$ 371,227	$ 409,719	$ 354,422	$ 240,556	$ 38,492	10%	-$ 130,671
5315	Customer Billing	$ 466,741	$ 517,916	$ 495,101	$ 964,616	$ 51,175	11%	$ 497,875
5320	Collecting	$ 300,111	$ 334,793	$ 322,653	$ 536,496	$ 34,682	12%	$ 236,385
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -	$ -		$ -
5330	Collection Charges	$ 2,251	$ 282	$ 833	$ 500	-$ 1,969	-87%	-$ 1,751
5335	Bad Debt Expense	$ 183,090	$ 130,318	$ 307,532	$ 306,000	-$ 52,772	-29%	$ 122,910
5340	Miscellaneous Customer Accounts Expenses	$ 649,367	$ 418,492	$ 403,316	$ 522,675	-$ 230,875	-36%	-$ 126,692
Total - Billing and Collecting		$ 2,107,836	$ 1,978,917	$ 2,045,182	$ 2,863,215	-$ 128,919	-6%	$ 755,379
Account	**Description**							
Community Relations								
5405	Supervision	$ -	$ -	$ -	$ -	$ -		$ -
5410	Community Relations - Sundry	$ 114,588	$ 106,288	$ 106,211	$ 152,526	-$ 8,300	-7%	$ 37,938
5415	Energy Conservation	$ -	$ -	$ -	$ -	$ -		$ -
5420	Community Safety Program	$ 12,743	$ 6,949	$ 9,412	$ 19,051	-$ 5,794	-45%	$ 6,308
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ 61,200	$ -		$ 61,200
5505	Supervision	$ -	$ -	$ -	$ -	$ -		$ -
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -		$ -
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -		$ -
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -		$ -
Total - Community Relations		$ 127,331	$ 113,237	$ 115,623	$ 232,777	-$ 14,094	-11%	$ 105,446
Account	**Description**							
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 392,793	$ 424,360	$ 319,673	$ 729,401	$ 31,567	8%	$ 336,608
5610	Management Salaries and Expenses	$ 662,071	$ 370,449	$ 302,363	$ 384,158	-$ 291,622	-44%	-$ 277,913
5615	General Administrative Salaries and Expenses	$ 664,697	$ 909,393	$ 884,744	$ 582,990	$ 244,696	37%	-$ 81,707
5620	Office Supplies and Expenses	$ 48,202	$ 65,707	$ 51,082	$ 80,250	$ 17,505	36%	$ 32,048
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -		$ -
5630	Outside Services Employed	$ 164,324	$ 110,786	$ 127,715	$ 220,000	-$ 53,538	-33%	$ 55,676
5635	Property Insurance	$ -	$ 151,793	$ 99,678	$ 133,133	$ 151,793		$ 133,133
5640	Injuries and Damages	$ -	$ 12,642	$ -	$ -	$ 12,642		$ -

5645 OMERS Pensions and Benefits	$ 101,036	$ 220,062	$ 175,099	$ 108,000	$ 119,026	118%	$ 6,964
5646 Employee Pensions and OPEB	$ -	$ -	$ -	$ -	$ -		$ -
5647 Employee Sick Leave	$ -	$ -	$ -	$ -	$ -		$ -
5650 Franchise Requirements	$ 49,316	$ 50,130	$ 53,775	$ 59,000	$ 814	2%	$ 9,684
5655 Regulatory Expenses	$ 196,822	$ 248,012	$ 120,735	$ 144,500	$ 51,190	26%	-$ 52,322
5660 General Advertising Expenses	$ 23,802	$ 27,062	$ 15,894	$ 40,000	$ 3,260	14%	$ 16,198
5665 Miscellaneous General Expenses	$ 171,754	$ 184,695	$ 151,291	-$ 1,995	$ 12,941	8%	-$ 173,749
5670 Rent	$ -	$ -	$ -	$ -	$ -		$ -
5672 Lease Payment Charge	$ -	$ -	$ -	$ -	$ -		$ -
5675 Maintenance of General Plant	$ 54,927	$ -	$ -	$ -	-$ 54,927	-100%	-$ 54,927
5680 Electrical Safety Authority Fees	$ 18,309	$ 15,642	$ 16,013	$ 19,000	-$ 2,667	-15%	$ 691
5681 Special Purpose Charge Expense	$ -	$ -	$ -	$ -	$ -		$ -
5685 Independent Electricity System Operator Fees and Penalties	$ -	$ 54,425	$ 51,758	$ -	$ 54,425		$ -
5695 OM&A Contra Account	$ -	-$ 19,371	-$ 51,215	$ -	-$ 19,371		$ -
6205 Donations	$ -				$ -		$ -
6205 Donations, Sub-account LEAP Funding	$ -	$ -	$ -		$ -		$ -
Total - Administrative and General Expenses	$ 2,548,053	$ 2,825,788	$ 2,318,604	$ 2,498,437	$ 277,735	11%	-$ 49,616
Total OM&A	$ 7,506,774	$ 7,693,996	$ 7,012,336	$ 9,204,025	$ 187,222	2%	$ 1,697,251
Adjustments for non-recoverable items							
5681 Special Purpose Charge Expense	$ -		$ -	$ -			$ -
6205 Donations[1]	$ -						$ -
							$ -
							$ -
							$ -
Total Recoverable OM&A	$ 7,506,774	$ 7,693,996	$ 7,012,336	$ 9,204,025	$ 187,222	2%	$ 1,697,251

[1] Account 6205 - Donations is generally non-recoverable. However, the sub-account LEAP funding of account 6205 is generally recoverable.

Note:

1 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, Column D "Most Current Actual Year" must be provided on CGAAP.
2 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, Column D "Most Current Actual Year" must be provided on that standar

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Appendix 2-I
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2008 BA)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations	$ 998,220	$ 1,018,908	$ 1,057,112	$ 1,008,391	$ 1,076,343	$ 1,111,298	$ 1,576,506
Maintenance	$ 1,725,334	$ 1,757,147	$ 1,723,356	$ 1,681,173	$ 1,456,583	$ 1,802,869	$ 2,033,090
SubTotal	**$ 2,723,554**	**$ 2,776,055**	**$ 2,780,468**	**$ 2,689,564**	**$ 2,532,926**	**$ 2,914,167**	**$ 3,609,596**
%Change (year over year)				-3.1%	-5.8%	15.1%	23.9%
%Change (Test Year vs Last Rebasing Year - Actual)							30.0%
Billing and Collecting	$ 2,107,836	$ 1,978,917	$ 2,205,690	$ 2,166,453	$ 2,045,182	$ 2,208,332	$ 2,863,215
Community Relations	$ 127,331	$ 113,237	$ 127,829	$ 131,379	$ 115,623	$ 169,137	$ 232,777
Administrative and General	$ 2,548,053	$ 2,825,788	$ 2,614,082	$ 2,594,789	$ 2,318,604	$ 2,521,038	$ 2,498,437
SubTotal	**$ 4,783,220**	**$ 4,917,942**	**$ 4,947,601**	**$ 4,892,621**	**$ 4,479,409**	**$ 4,898,507**	**$ 5,594,429**
%Change (year over year)				-0.5%	-8.4%	9.4%	14.2%
%Change (Test Year vs Last Rebasing Year - Actual)							13.8%
Total	**$ 7,506,774**	**$ 7,693,997**	**$ 7,728,069**	**$ 7,582,186**	**$ 7,012,335**	**$ 7,812,674**	**$ 9,204,025**
%Change (year over year)				-1.5%	-7.5%	11.4%	17.8%

	Last Rebasing Year (2008 BA)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Operations	$ 998,220	$ 1,018,908	$ 1,057,112	$ 1,008,391	$ 1,076,343	$ 1,111,298	$ 1,576,506
Maintenance	$ 1,725,334	$ 1,757,147	$ 1,723,356	$ 1,681,173	$ 1,456,583	$ 1,802,869	$ 2,033,090
Billing and Collecting	$ 2,107,836	$ 1,978,917	$ 2,205,690	$ 2,166,453	$ 2,045,182	$ 2,208,332	$ 2,863,215
Community Relations	$ 127,331	$ 113,237	$ 127,829	$ 131,379	$ 115,623	$ 169,137	$ 232,777
Administrative and General	$ 2,548,053	$ 2,825,788	$ 2,614,082	$ 2,594,789	$ 2,318,604	$ 2,521,038	$ 2,498,437
Total	**$ 7,506,774**	**$ 7,693,997**	**$ 7,728,069**	**$ 7,582,186**	**$ 7,012,335**	**$ 7,812,674**	**$ 9,204,025**
%Change (year over year)				-1.5%	-7.5%	11.4%	17.8%

	Last Rebasing Year (2008 BA)	Last Rebasing Year (2008 Actuals)	2009 Actuals	Variance 2008 BA – 2008 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2008 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2013 Test Year
Operations	$ 998,220	$ 1,018,908	$ 1,057,112	-$ 20,688	$ 1,008,391	-$ 10,517	$ 1,076,343	$ 67,951	$ 1,111,298	$ 34,955	$ 1,576,506
Maintenance	$ 1,725,334	$ 1,757,147	$ 1,723,356	-$ 31,813	$ 1,681,173	-$ 75,973	$ 1,456,583	-$ 224,590	$ 1,802,869	$ 346,286	$ 2,033,090
Billing and Collecting	$ 2,107,836	$ 1,978,917	$ 2,205,690	$ 128,919	$ 2,166,453	$ 187,536	$ 2,045,182	-$ 121,271	$ 2,208,332	$ 163,150	$ 2,863,215
Community Relations	$ 127,331	$ 113,237	$ 127,829	$ 14,094	$ 131,379	$ 18,143	$ 115,623	-$ 15,756	$ 169,137	$ 53,514	$ 232,777
Administrative and General	$ 2,548,053	$ 2,825,788	$ 2,614,082	-$ 277,735	$ 2,594,789	-$ 230,999	$ 2,318,604	-$ 276,185	$ 2,521,038	$ 202,434	$ 2,498,437
Total OM&A Expenses	$ 7,506,774	$ 7,693,997	$ 7,728,069	-$ 187,223	$ 7,582,186	-$ 111,811	$ 7,012,335	-$ 569,850	$ 7,812,674	$ 800,338	$ 9,204,025
Variance from previous year			$ 34,072		-$ 145,883		-$ 569,850		$ 800,338		$ 1,391,351
Percent change (year over year)			0.4%		-1.9%		-8%		11%		18%
Percent Change: Test year vs. Most Current Actual							31.25%				
Simple average of % variance for all years							19.63%				
Compound Annual Growth Rate for all years											
Compound Growth Rate (2011 Actuals vs. 2008 Actuals)							-3.04%				

Note:

1 "BA" = Board-Approved
2 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of se application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-H.

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-J has been attached separately due to an apparent glitch with this worksheet.

OM&A Cost Driver Table

OM&A	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-K
Employee Costs

	Last Rebasing Year (2008 Board-Approved)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Employees (FTEs including Part-Time)[1]						
Executive	1.18					5.55
Management	13.82	12.20	12.75	12.80	14.17	11.70
Non-Union	11.24	4.45	4.75	4.75	3.67	4.00
Union	45.63	39.12	39.35	39.40	39.00	34.81
Total	72	55.77	56.85	56.95	56.84	56.06
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union	3.02	8.00	11.00	10.00	8.00	11.00
Total	3.02	8	11	10	8	11
Total Salary and Wages						
Executive						$ 712,228
Management	$ 1,559,871	$ 1,147,194	$ 1,219,554	$ 1,301,936	$ 1,402,207	$ 962,124
Non-Union	$ 692,837	$ 292,969	$ 333,514	$ 347,469	$ 264,318	$ 255,555
Union	$ 2,539,737	$ 2,196,881	$ 2,329,720	$ 2,413,326	$ 2,480,547	$ 2,235,145
Total	$ 4,792,445	$ 3,637,044	$ 3,882,789	$ 4,062,731	$ 4,147,072	$ 4,165,053
Current Benefits						
Executive						$ 130,294
Management	$ 335,518	$ 237,714	$ 253,607	$ 268,332	$ 265,271	$ 247,095
Non-Union	$ 134,221	$ 59,072	$ 70,466	$ 81,232	$ 58,530	$ 59,753
Union	$ 579,203	$ 474,509	$ 537,308	$ 579,923	$ 573,342	$ 568,262
Total	$ 1,048,942	$ 771,295	$ 861,381	$ 929,487	$ 897,143	$ 1,005,404
Accrued Pension and Post-Retirement Benefits						
Executive						$ 223,955
Management						$ 16,691
Non-Union						$ 6,955
Union						$ 54,400
Total	$ 849,005	$ 220,062	$ 244,532	$ 215,393	$ 175,099	$ 302,001
Executive	$ -	$ -	$ -	$ -	$ -	$ 354,249
Management	$ 335,518	$ 237,714	$ 253,607	$ 268,332	$ 265,271	$ 263,786
Non-Union	$ 134,221	$ 59,072	$ 70,466	$ 81,232	$ 58,530	$ 66,708
Union	$ 579,203	$ 474,509	$ 537,308	$ 579,923	$ 573,342	$ 622,662
Total	$ 1,897,947	$ 991,357	$ 1,105,913	$ 1,144,880	$ 1,072,242	$ 1,307,405
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ 1,066,477
Management	$ 1,895,389	$ 1,384,907	$ 1,473,161	$ 1,570,268	$ 1,667,478	$ 1,225,911
Non-Union	$ 827,058	$ 352,042	$ 403,980	$ 428,701	$ 322,848	$ 322,263
Union	$ 3,118,940	$ 2,671,390	$ 2,867,028	$ 2,993,249	$ 3,053,889	$ 2,857,807
Total	$ 6,690,392	$ 4,628,401	$ 4,988,702	$ 5,207,611	$ 5,219,314	$ 5,472,457
Compensation - Average Yearly Base Wages						
Executive						$ 128,329
Management	$ 1,559,871	$ 94,031	$ 95,651	$ 101,714	$ 98,928	$ 82,032
Non-Union	$ 692,837	$ 64,479	$ 70,214	$ 73,112	$ 71,971	$ 62,948
Union	$ 2,418,902	$ 52,243	$ 56,338	$ 57,942	$ 60,611	$ 61,558
Total		$ 62,362	$ 66,315	$ 69,046	$ 70,898	$ 72,541
Compensation - Average Yearly Overtime						
Executive						$ -
Management	$ -	$ 1	$ -	$ -	$ 5	$ 201
Non-Union	$ -	$ 1,357	$ -	$ 40	$ 116	$ 940
Union	$ 120,835	$ 3,919	$ 2,867	$ 3,313	$ 2,996	$ 2,652
Total		$ 2,857	$ 1,984	$ 2,295	$ 2,064	$ 1,756
Compensation - Average Yearly Incentive Pay						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -
Compensation - Average Yearly Benefits						
Executive		$ -	$ -	$ -	$ -	$ 63,829
Management	$ 24,278	$ 19,485	$ 19,891	$ 20,963	$ 18,716	$ 22,546
Non-Union	$ 11,941	$ 13,275	$ 14,835	$ 17,101	$ 15,963	$ 16,677
Union	$ 12,693	$ 12,131	$ 13,655	$ 14,720	$ 14,702	$ 17,887
Total	$ 16,304	$ 17,777	$ 19,453	$ 20,104	$ 18,865	$ 23,322
Total Compensation	$ 5,841,387	$ 4,408,339	$ 4,744,170	$ 4,992,218	$ 5,044,215	$ 5,472,457
Total Compensation Capitalized (CGAAP)		$ 590,036	$ 581,488	$ 797,582	$ 797,414	$ 755,903
Total Compensation Charged to OM&A (CGAAP)	$ 5,841,387.00	$ 3,818,302.73	$ 4,162,681.58	$ 4,194,635.90	$ 4,246,800.74	$ 4,716,554.34
Total Compensation Capitalized (MIFRS)						
Total Compensation Charged to OM&A (MIFRS)					$ 5,044,214.74	$ 5,472,457.34

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

Note:

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTEE

	Last Rebasing Year (2008 Board-Approved)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	34,960	36,756	37,038	37,320	37,747	38,058
Total Recoverable OM&A from Appendix 2-I	$ 7,506,774	$ 7,693,996	$ 7,728,069	$ 7,582,186	$ 7,012,336	$ 7,812,674
OM&A cost per customer	$ 215	$ 209	$ 209	$ 203	$ 186	$ 205
Number of FTEEs	72	56	57	57	57	56
Customers/FTEEs	486.43	659.11	649.79	658.81	664.11	678.89
OM&A Cost per FTEE	104,449	137,968	135,580	133,847	123,373	139,363

Notes:

The method of calculating the number of customers: the monthly average number (the sum of the total number of customers at t
The method of calculating the number of FTEEs - 61 direct employees of BPI and 9.5 indirect employees providing services thr

File Number:	EB-2012-0109
Exhibit:	4
Tab:	2
Schedule:	1
Page:	26
Date:	July 17,2013

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2008 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 100,000	$ 104,380	$ 108,000	3.47%	$ 108,000	0.00%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Time	$ 10,000	$ -	$ -			
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Time	$ 5,000	$ -	$ -		$ 10,000	
4	Expert Witness costs for regulatory matters	5655		On-Time	$ 10,000	$ -	$ -			
5	Legal costs for regulatory matters	5630		On-Time	$ 45,000	$ 8,479	$ 10,000	17.94%	$ 29,750	197.50%
6	Consultants' costs for regulatory matters	5655		On-Time	$ 50,000	$ 9,000	$ 10,000	11.11%	$ 29,750	197.50%
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 274,093	$ 217,863	$ 210,004	-3.61%	$ 283,016	34.77%
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5655		On-Going	$ 5,000	$ 20,799	$ 27,722	33.28%	$ 21,108	-23.86%
9	Other regulatory agency fees or assessments (ESA)	5655		On-Going	$ 20,000	$ 16,013	$ 16,400	2.42%	$ 19,000	15.85%
10	Any other costs for regulatory matters (courier fees, communications company)	5655		On-Going	$ -	$ 534	$ 7,000	1212.02%		-100.00%
11	Intervenor costs	5655		On-Time	$ -	$ 5,498	$ 7,500	36.41%	$ 7,500	0.00%
12	Sub-total - Ongoing Costs [3]		$ -		$ 399,093	$ 359,589	$ 369,126	2.65%	$ 431,124	16.80%
13	Sub-total - One-time Costs [4]		$ -		$ 120,000	$ 22,977	$ 27,500	19.69%	$ 77,000	180.00%
14	Total		$ -		$ 519,093	$ 382,565	$ 396,626	3.68%	$ 508,124	28.11%

1 Please identify the resources involved.

2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.

3 Sum of all ongoing costs identified in rows 1 to 11 inclusive.

4 Sum of all one-time costs identified in rows 1 to 11 inclusive.

Please fill out the following table for all one-time costs related to this cost of service application

		Historical Year(s)	2012 Bridge Year	2013 Test Year
4	Expert Witness costs for regulatory matters		$ -	$ -
6	Consultants' costs for regulatory matters		$ 10,000	$ 29,750
7	Operating expenses associated with staff resources allocated to regulatory matters		$ -	$ -
8	Operating expenses associated with other resources allocated to regulatory matters [1]		$ -	$ -
11	Intervenor costs		$ 7,500	$ 7,500

Appendix 2-N
Shared Services and Corporate Cos

Year: 2008 Board Approved

Shared Services

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Power Inc.	Mail Services
City of Brantford	Brantford Power Inc.	Insurance and Risk Management
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Power Inc.	Utilities Accounting
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Power Inc.	IT Services
City of Brantford	Brantford Power Inc.	Facilities
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Power Inc.	Forestry
City of Brantford	Brantford Power Inc.	Senior Management

Total - Shared Services that BPI continues to purchase in 2013 under renegotiated Service Leve

Corporate Cost Allocation

Name of Company		Service Offered
From	To	
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	General Mail Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Insurance and Risk Management Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - CFO
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - Other
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Utility Accounting Services - Total**
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 84 Market Street
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 400 Grand River Avenue
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - Vehicle Storage - 400 Grand River Avenue
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 220 Colborne Street
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Facilities - Total**
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Hydro Inc.	

City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Network
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Utility Specific
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**IT Services - Total**
City of Brantford	Brantford Power Inc.	Senior Management Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	

Note:

1 **This appendix must be completed in relation to each service provided (**

Prior to the renegotiation of the Service Level Agreement between BPI and tl
group of companies and then allocated among the Energy group. The table

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	27
Date:	July 17,2013

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Pricing Methdology	Price for the Service $	Cost for the Service $
Cost-based with mark-up as a proxy for market	$ 13,284.00	$ 13,284.00
Cost-based with mark-up as a proxy for market	$ 20,250.00	$ 20,250.00
Cost-based with mark-up as a proxy for market	$ 5,738.00	$ 5,738.00
Market-based [premiums], Cost-based [Administration]	$ 216,000.00	$ 216,000.00
Cost-based with mark-up as a proxy for market	$ 1,152,752.00	$ 1,152,752.00
Cost-based with mark-up as a proxy for market	$ 40,500.00	$ 40,500.00
Cost-based with mark-up as a proxy for market	$ 359,663.00	$ 359,663.00
Cost-based with mark-up as a proxy for market	$ 172,850.00	$ 172,850.00
Cost-based with mark-up as a proxy for market	$ 268,548.00	$ 268,548.00
Cost-based with mark-up as a proxy for market	$ 966,000.00	$ 966,000.00
Cost-based with mark-up as a proxy for market	$ 807,313.00	$ 807,313.00
Cost-based with mark-up as a proxy for market	$ 60,314.00	$ 60,314.00
Cost-based with mark-up as a proxy for market	$ 67,178.00	$ 67,178.00
Market-based [third-party services]; Cost-based [Administration]	$ 331,969.00	$ 331,969.00
Cost-based with mark-up as a proxy for market	$ 35,025.00	$ 35,025.00
el Agreement	**$ 2,723,137.00**	**$ 2,723,137.00**

Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
	%	$
	33	$ 13,284.00
	33	
% of time contracted	33	
	90	$ 20,250.00
	5	
% of total assets	5	
	85	$ 5,738.00
	10	
Estimate of time	5	
	90	$ 216,000.00
	5	
% of total assets	5	
	96	$1,152,752.00
	4	
Estimate of time	0	
	90	$ 40,500.00
	5	
% of total assets	5	
	90	$ 172,850.00
	5	
% of total assets	5	
	70	See Row 67
	25	
% of time contracted	5	
	60	See Row 67
	35	
Estimate of time	5	
		$ 359,663.00
	90	$ 268,548.00
	5	
% of total assets	5	
	75	See Row 83
	20	
	5	
	95	See Row 83
	5	
	0	
	98.4	See Row 83
	1.6	
% of square footage utilized	0	
	90	See Row 83
	5	
% of total assets	5	
		$ 807,313.00
	90	$ 60,314.00
	5	

% of total assets	5	
	90	$ 67,178.00
	5	
% of total assets	5	
	90	See Row 96
	5	
% of total assets	5	
Actual csts for materials and projects plus allocation of administrative costs	N/A	See Row 96
	N/A	
	N/A	
		$ 966,000.00
	80	$ 35,025.00
	10	
Estimate of time	10	

or received for the Historical (actuals), Bridge and Test years.

he City, costs were passed from the City of Brantford to the Energy above sets out the allocation percentages in place at that time.

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	28
Date:	July 17,2013

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2008 Actual

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
City of Brantford	Brantford Power Inc.	Operations and Maintenance	Cost-based with mark-up as a proxy for market	$ 1,296,472.41	$1,296,472.41
City of Brantford	Brantford Power Inc.	Vehicle Maintenance	Cost-based with mark-up as a proxy for market	$ 213,715.42	$ 213,715.42
City of Brantford	Brantford Power Inc.	Engineering	Cost-based with mark-up as a proxy for market	$ 945,736.76	$ 945,736.76
City of Brantford	Brantford Power Inc.	Metering & Settlement	Cost-based with mark-up as a proxy for market	$ 715,665.71	$ 715,665.71
City of Brantford	Brantford Power Inc.	Line Locates	Cost-based with mark-up as a proxy for market	$ 95,430.10	$ 95,430.10
City of Brantford	Brantford Power Inc.	Regulatory & Administration	Cost-based with mark-up as a proxy for market	$ 459,615.72	$ 459,615.72
City of Brantford	Brantford Power Inc.	Meeting Management Services	Cost-based with mark-up as a proxy for market	$ 13,284.00	$ 13,284.00
City of Brantford	Brantford Power Inc.	Records Management	Cost-based with mark-up as a proxy for market	$ 18,728.52	$ 18,728.52
City of Brantford	Brantford Power Inc.	Mail Services	Cost-based with mark-up as a proxy for market	$ 5,030.22	$ 5,030.22
City of Brantford	Brantford Power Inc.	Insurance and Risk Management	Market-based [premiums], Cost-based [Administration]	$ 190,256.88	$ 190,256.88
City of Brantford	Brantford Power Inc.	Customer Services	Cost-based with mark-up as a proxy for market	$ 1,048,109.82	$1,048,109.82
City of Brantford	Brantford Power Inc.	Telephone Services	Cost-based with mark-up as a proxy for market	$ 37,795.87	$ 37,795.87
City of Brantford	Brantford Power Inc.	Utilities Accounting	Cost-based with mark-up as a proxy for market	$ 385,228.41	$ 385,228.41
City of Brantford	Brantford Power Inc.	Treasury, Purchasing	Cost-based with mark-up as a proxy for market	$ 172,850.40	$ 172,850.40
City of Brantford	Brantford Power Inc.	Inventory Management	Cost-based with mark-up as a proxy for market	$ 254,360.22	$ 254,360.22
City of Brantford	Brantford Power Inc.	IT Services	Cost-based with mark-up as a proxy for market	$ 802,580.27	$ 802,580.27
City of Brantford	Brantford Power Inc.	Facilities	Cost-based with mark-up as a proxy for market	$ 747,335.53	$ 747,335.53
City of Brantford	Brantford Power Inc.	Legal Services	Cost-based with mark-up as a proxy for market	$ 136,360.57	$ 136,360.57
City of Brantford	Brantford Power Inc.	Human Resources	Cost-based with mark-up as a proxy for market	$ 69,824.98	$ 69,824.98
City of Brantford	Brantford Power Inc.	Forestry	Market-based [third-party services]; Cost-based [Administration]	$ 424,149.98	$ 424,149.98
City of Brantford	Brantford Power Inc.	Senior Management	Cost-based with mark-up as a proxy for market	$ 33,356.76	$ 33,356.76
Total - Shared Services that BPI continues to purchase in 2013 under renegotiated Service Level Agreement				**$ 2,638,269.98**	**$2,638,269.98**

Corporate Cost Allocation

Appendix 2-N
Shared Services and Corporate

Year: 2009

Shared Services

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Operations and Maintenance
City of Brantford	Brantford Power Inc.	Vehicle Maintenance
City of Brantford	Brantford Power Inc.	Engineering
City of Brantford	Brantford Power Inc.	Metering & Settlement
City of Brantford	Brantford Power Inc.	Line Locates
City of Brantford	Brantford Power Inc.	Regulatory & Administration
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Power Inc.	Mail Services
City of Brantford	Brantford Power Inc.	Insurance and Risk Management
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Power Inc.	Utilities Accounting
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Power Inc.	IT Services
City of Brantford	Brantford Power Inc.	Facilities

City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Power Inc.	Forestry
City of Brantford	Brantford Power Inc.	Senior Management

Total - Shared Services that BPI continues to purchase in 2013 under renegotiated Ser

Corporate Cost Alloca

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	General Mail Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Insurance and Risk Management Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - CFO
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - Other
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Utility Accounting Services - Total**
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 84 Market Street

City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 400 Grand River Avenue
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - Vehicle Storage - 400 Grand River Avenue
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 220 Colborne Street
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Facilities - Total**
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Network
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Utility Specific
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**IT Services - Total**
City of Brantford	Brantford Power Inc.	Senior Management Services
City of Brantford	Brantford Hydro Inc.	
City of Brantford	Brantford Energy Corporation	

Note:

1 **This appendix must be completed in relation to each service p years.**

NOTES

Prior to the renegotiation of the Service Level Agreement between Energy group of companies and then allocated among the Energy

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	29
Date:	July 17,2013

e Cost Allocatioı

Pricing Methdology	Price for the Service $	Cost for the Service $
Cost-based with mark-up as a proxy for market	$ 1,412,335.55	$ 1,412,335.55
Cost-based with mark-up as a proxy for market	$ 206,471.65	$ 206,471.65
Cost-based with mark-up as a proxy for market	$ 968,967.63	$ 968,967.63
Cost-based with mark-up as a proxy for market	$ 984,641.06	$ 984,641.06
Cost-based with mark-up as a proxy for market	$ 113,817.06	$ 113,817.06
Cost-based with mark-up as a proxy for market	$ 499,774.17	$ 499,774.17
Cost-based with mark-up as a proxy for market	$ 13,284.00	$ 13,284.00
Cost-based with mark-up as a proxy for market	$ 18,728.52	$ 18,728.52
Cost-based with mark-up as a proxy for market	$ 4,726.29	$ 4,726.29
Market-based [premiums], Cost-based [Administration]	$ 134,301.58	$ 134,301.58
Cost-based with mark-up as a proxy for market	$ 1,133,497.10	$ 1,133,497.10
Cost-based with mark-up as a proxy for market	$ 43,565.80	$ 43,565.80
Cost-based with mark-up as a proxy for market	$ 371,349.73	$ 371,349.73
Cost-based with mark-up as a proxy for market	$ 157,154.40	$ 157,154.40
Cost-based with mark-up as a proxy for market	$ 272,541.50	$ 272,541.50
Cost-based with mark-up as a proxy for market	$ 786,767.13	$ 786,767.13
Cost-based with mark-up as a proxy for market	$ 692,039.05	$ 692,039.05

Cost-based with mark-up as a proxy for market	$ 73,283.59	$ 73,283.59
Cost-based with mark-up as a proxy for market	$ 70,918.26	$ 70,918.26
Market-based [third-party services]; Cost-based [Administration]	$ 380,850.00	$ 380,850.00
Cost-based with mark-up as a proxy for market	$ 36,128.04	$ 36,128.04

rvice Level Agreement	**$ 2,398,462.66**	**$ 2,398,462.66**

tion

Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
	%	$
	33	$ 13,284.00
	33	
% of time contracted	33	
	90	$ 18,728.52
	5	
% of total assets	5	
	85	$ 4,726.29
	10	
Estimate of time	5	
	90	$ 43,565.80
	5	
% of total assets	5	
	96	$ 1,133,497.10
	4	
Estimate of time	0	
	90	$ 43,565.80
	5	
% of total assets	5	
	90	$ 157,154.40
	5	
% of total assets	5	
	65	See Row 74
	30	
% of time contracted	5	
	60	See Row 74
	35	
Estimate of time	5	
		$ 371,349.73
	90	$ 272,541.50
	5	
% of total assets	5	
	75	See Row 89

	20	
	5	
	95	See Row 89
	5	
	0	
	98.4	See Row 89
	1.6	
% of square footage utilized	0	
	90	See Row 89
	5	
% of total assets	5	
		$ 692,039.05
	90	$ 73,283.59
	5	
% of total assets	5	
	90	$ 70,918.26
	5	
% of total assets	5	
	90	See Row 103
	5	
% of total assets	5	
Actual csts for materials and	N/A	See Row 103
projects plus allocation of	N/A	
administrative costs	N/A	
		$ 786,767.13
	80	$ 36,128.04
	10	
Estimate of time	10	

ɔrovided or received for the Historical (actuals), Bridge and Test

BPI and the City, costs were passed from the City of Brantford to the group. The table above sets out the allocation percentages in place

Appendix 2-N
Shared Services and Corporat

Year: 2010

Shared Services

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Operations and Maintenance
City of Brantford	Brantford Power Inc.	Vehicle Maintenance
City of Brantford	Brantford Power Inc.	Engineering
City of Brantford	Brantford Power Inc.	Metering & Settlement
City of Brantford	Brantford Power Inc.	Line Locates
City of Brantford	Brantford Power Inc.	Regulatory & Administration
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Power Inc.	Mail Services
City of Brantford	Brantford Power Inc.	Insurance and Risk Management
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Power Inc.	Utilities Accounting
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Power Inc.	IT Services
City of Brantford	Brantford Power Inc.	Facilities

City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Power Inc.	Forestry
City of Brantford	Brantford Power Inc.	Senior Management

Total - Shared Services that BPI continues to purchase in 2013 under renegotiated Servi

Corporate Cost Alloc

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	General Mail Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Insurance and Risk Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - CFO
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - Other
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Utility Accounting Services - Total**
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 84 Market Street
City of Brantford	Brantford Hydro/Generation Inc.	

City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 400 Grand River Avenue
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - Vehicle Storage - 400 Grand River Avenue
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 220 Colborne Street
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Facilities - Total**
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Network
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Utility Specific
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**IT Services - Total**
City of Brantford	Brantford Power Inc.	Senior Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	

Note:

1 **This appendix must be completed in relation to each service pro**

NOTES

Prior to the renegotiation of the Service Level Agreement between BI
Energy group of companies and then allocated among the Energy gr

With the incorporation of Brantford Generation in 2010, which receive
allocated to Brantford Hydro were split between both Brantford Hydro

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	30
Date:	July 17,2013

te Cost Allocatior

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Pricing Methdology	Price for the Service $	Cost for the Service $
Cost-based with mark-up as a proxy for market	$ 1,463,082.40	$ 1,463,082.40
Cost-based with mark-up as a proxy for market	$ 224,170.33	$ 224,170.33
Cost-based with mark-up as a proxy for market	$ 895,601.15	$ 895,601.15
Cost-based with mark-up as a proxy for market	$ 893,460.65	$ 893,460.65
Cost-based with mark-up as a proxy for market	$ 105,443.50	$ 105,443.50
Cost-based with mark-up as a proxy for market	$ 497,003.83	$ 497,003.83
Cost-based with mark-up as a proxy for market	$ 13,284.00	$ 13,284.00
Cost-based with mark-up as a proxy for market	$ 18,728.52	$ 18,728.52
Cost-based with mark-up as a proxy for market	$ 3,752.99	$ 3,752.99
Market-based [premiums], Cost-based [Administration]	$ 106,862.43	$ 106,862.43
Cost-based with mark-up as a proxy for market	$ 1,146,388.10	$ 1,146,388.10
Cost-based with mark-up as a proxy for market	$ 44,808.73	$ 44,808.73
Cost-based with mark-up as a proxy for market	$ 406,951.40	$ 406,951.40
Cost-based with mark-up as a proxy for market	$ 157,154.44	$ 157,154.44
Cost-based with mark-up as a proxy for market	$ 268,025.47	$ 268,025.47
Cost-based with mark-up as a proxy for market	$ 887,476.71	$ 887,476.71
Cost-based with mark-up as a proxy for market	$ 674,953.47	$ 674,953.47

Cost-based with mark-up as a proxy for market	$ 59,417.58	$ 59,417.58
Cost-based with mark-up as a proxy for market	$ 72,536.04	$ 72,536.04
Market-based [third-party services]; Cost-based [Administration]	$ 384,069.06	$ 384,069.06
Cost-based with mark-up as a proxy for market	$ 37,205.64	$ 37,205.64

ice Level Agreement	**$ 2,446,965.61**	**$ 2,446,965.61**

ation

Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
	%	$
	33	$ 13,284.00
	33	
% of time contracted	33	
	90	$ 18,728.52
	5	
% of total assets	5	
	85	$ 3,752.99
	10	
Estimate of time	5	
	90	$ 106,862.43
	5	
% of total assets	5	
	96	$ 1,146,388.10
	4	
Estimate of time	0	
	90	$ 44,808.73
	5	
% of total assets	5	
	90	$ 157,154.44
	5	
% of total assets	5	
	65	See Row 74
	30	
% of time contracted	5	
	60	See Row 74
	35	
Estimate of time	5	
		$ 406,951.40
	90	$ 268,025.47
	5	
% of total assets	5	
	75	See Row 90
	20	

	5	
	95	See Row 90
	5	
	0	
	98.4	See Row 90
	1.6	
% of square footage utilized	0	
	90	See Row 90
	5	
% of total assets	5	
		$ 674,953.47
	90	$ 59,417.58
	5	
% of total assets	5	
	90	$ 72,536.04
	5	
% of total assets	5	
	90	See Row 103
	5	
% of total assets	5	
	N/A	See Row 103
Actual csts for materials and projects	N/A	
plus allocation of administrative costs	N/A	
		$ 887,476.71
	80	$ 37,205.64
	10	
Estimate of time	10	

ovided or received for the Historical (actuals), Bridge and Test years.

PI and the City, costs were passed from the City of Brantford to the
oup. The table above sets out the allocation percentages in place at that

ed operational services from Brantford Hydro Inc, costs previously
and Brantford Generation

Appendix 2-N
Shared Services and Corporate (

Year: 2011

Shared Services

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Operations and Maintenance
City of Brantford	Brantford Power Inc.	Vehicle Maintenance
City of Brantford	Brantford Power Inc.	Engineering
City of Brantford	Brantford Power Inc.	Metering & Settlement
City of Brantford	Brantford Power Inc.	Line Locates
City of Brantford	Brantford Power Inc.	Regulatory & Administration
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Power Inc.	Mail Services
City of Brantford	Brantford Power Inc.	Insurance and Risk Management
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Power Inc.	Utilities Accounting
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Power Inc.	IT Services
City of Brantford	Brantford Power Inc.	Facilities
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Power Inc.	Forestry
City of Brantford	Brantford Power Inc.	Senior Management

Total - Shared Services that BPI continues to purchase in 2013 under renegotiated Servi

NOTES: The10% mark-up as a proxy for market that had been applied to cos
Costs for Senior Management Services were removed in 2011

Corporate Cost Allocat

Name of Company		Service Offered
From	**To**	

City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	General Mail Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Insurance and Risk Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - CFO
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - Other
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Utility Accounting Services - Total**
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 84 Market Street
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 400 Grand River Avenue
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - Vehicle Storage - 400 Grand River Avenue
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 220 Colborne Street
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Facilities - Total**
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Hydro/Generation Inc.	

City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Network
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Utility Specific
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**IT Services - Total**
City of Brantford	Brantford Power Inc.	Senior Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	

Note:

1 **This appendix must be completed in relation to each service pr years.**

NOTES

Prior to the renegotiation of the Service Level Agreement between Bl Energy group of companies and then allocated among the Energy gr

Allocation of costs for Customer Services between Brantford Power I to a 90/10 split

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	31
Date:	July 17,2013

Cost Allocatioı

Pricing Methdology	Price for the Service	Cost for the Service
	$	$
Cost-based	$ 1,315,542.90	$ 1,315,542.90
Cost-based	$ 187,121.12	$ 187,121.12
Cost-based	$ 847,245.82	$ 847,245.82
Cost-based	$ 824,579.41	$ 824,579.41
Cost-based	$ 97,571.22	$ 97,571.22
Cost-based	$ 507,703.34	$ 507,703.34
Cost-based	$ 13,284.00	$ 13,284.00
Cost-based	$ 17,025.96	$ 17,025.96
Cost-based	$ 2,818.62	$ 2,818.62
Market-based [premiums], Cost-based [Administration]	$ 130,910.04	$ 130,910.04
Cost-based	$ 1,066,712.83	$ 1,066,712.83
Cost-based	$ 51,754.99	$ 51,754.99
Cost-based	$ 329,721.16	$ 329,721.16
Cost-based	$ 160,253.09	$ 160,253.09
Cost-based	$ 220,971.65	$ 220,971.65
Cost-based	$ 768,301.83	$ 768,301.83
Cost-based	$ 592,494.90	$ 592,494.90
Cost-based	$ 65,891.62	$ 65,891.62
Cost-based	$ 65,437.83	$ 65,437.83
Market-based [third-party services]; Cost-based [Administration]	$ 330,240.65	$ 330,240.65
	$ -	$ -
ice Level Agreement	**$ 2,185,129.53**	**$ 2,185,129.53**

ıts was removed in 2011

ion

Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
	%	$

	33	$ 13,284.00
	33	
% of time contracted	33	
	90	$ 17,025.96
	5	
% of total assets	5	
	85	$ 2,818.62
	10	
Estimate of time	5	
	90	$ 130,910.04
	5	
% of total assets	5	
	90	$ 1,066,712.83
	10	
Estimate of time	0	
	90	$ 51,754.99
	5	
% of total assets	5	
	90	$ 160,253.09
	5	
% of total assets	5	
	49	See Row 67
	46	
% of time contracted	5	
	60	See Row 67
	35	
Estimate of time	5	
		$ 329,721.16
	90	$ 220,971.65
	5	
% of total assets	5	
	75	See Row 83
	20	
	5	
	95	See Row 83
	5	
	0	
	98.4	See Row 83
	1.6	
% of square footage utilized	0	
	90	See Row 83
	5	
% of total assets	5	
		$ 592,494.90
	90	$ 65,891.62
	5	

% of total assets	5	
	90	$ 65,437.83
	5	
% of total assets	5	
	90	See Row 96
	5	
% of total assets	5	
Actual csts for materials and projects plus allocation of administrative costs	N/A	See Row 96
	N/A	
	N/A	
		$ 768,301.83
	80	$ -
	10	
Estimate of time	10	

ovided or received for the Historical (actuals), Bridge and Test

PI and the City, costs were passed from the City of Brantford to the
oup. The table above sets out the allocation percentages in place at

Inc. and Brantford Hydro Inc. were changed in 2011 from a 96/4 split

Appendix 2-N
Shared Services and Corporat

Year: 2012

Shared Services

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Operations and Maintenance
City of Brantford	Brantford Power Inc.	Vehicle Maintenance
City of Brantford	Brantford Power Inc.	Engineering
City of Brantford	Brantford Power Inc.	Metering & Settlement
City of Brantford	Brantford Power Inc.	Line Locates
City of Brantford	Brantford Power Inc.	Regulatory & Administration
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Power Inc.	Mail Services
City of Brantford	Brantford Power Inc.	Insurance and Risk Management
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Power Inc.	Utilities Accounting
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Power Inc.	IT Services
City of Brantford	Brantford Power Inc.	Facilities
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Power Inc.	Forestry
Brantford Power Inc.	City of Brantford	Street Light Maintenance
Brantford Power Inc.	Brantford Hydro Inc.	Sentinel Light Maintenance

Total - Shared Services that BPI continues to purchase in 2013 under renegotiated Servi

NOTES: Employees providing Operations and Maintenance, Engineering, Met
Management, Customer Services and Utilities Acccounting functions

Vehicle Maintenance Services are no longer included in the Service L

Line locates services have been outsourced through the provincial Or

Prior to the transfer of employees to BPI at April 1, 2012, employees c
Streetlighting and Sentinel Maintenance services to the City; that is, th

Corporate Cost Alloca

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Meeting Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	General Mail Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Insurance and Risk Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Customer Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Treasury, Purchasing
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - CFO
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Utilities Accounting Services - Other
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Utility Accounting Services - Total**
City of Brantford	Brantford Power Inc.	Inventory Management
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 84 Market Street
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 400 Grand River Avenue
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	

City of Brantford	Brantford Power Inc.	Property Management - Vehicle Storage - 400 Grand River Avenue
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Property Management - 220 Colborne Street
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**Facilities - Total**
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Network
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	Brantford Power Inc.	IT Services - Utility Specific
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	
City of Brantford	**Brantford Power Inc.**	**IT Services - Total**
City of Brantford	Brantford Power Inc.	Senior Management Services
City of Brantford	Brantford Hydro/Generation Inc.	
City of Brantford	Brantford Energy Corporation	

Note:

1 **This appendix must be completed in relation to each service pro**

NOTES

Prior to the renegotiation of the Service Level Agreement between BF
Energy group of companies and then allocated among the Energy grc

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	32
Date:	July 17,2013

:e Cost Allocatior

Pricing Methdology	Price for the Service	Cost for the Service
	$	$
Cost-based (from January 1 to March 31, 2012)	$ 349,418.81	$ 349,418.81
Cost-based	$ 170,005.92	$ 170,005.92
Cost-based (from January 1 to March 31, 2012)	$ 206,368.01	$ 206,368.01
Cost-based (from January 1 to March 31, 2012)	$ 174,520.10	$ 174,520.10
Cost-based (from January 1 to March 31, 2012)	$ 97,321.82	$ 97,321.82
Cost-based (from January 1 to March 31, 2012)	$ 220,207.42	$ 220,207.42
Cost-based	$ 3,321.00	$ 3,321.00
Cost-based	$ 17,025.96	$ 17,025.96
Cost-based	$ 3,459.68	$ 3,459.68
Market-based [premiums], Cost-based [Administration]	$ 133,664.04	$ 133,664.04
Cost-based	$ 493,021.06	$ 493,021.06
Cost-based	$ 46,207.50	$ 46,207.50
Cost-based	$ 88,765.38	$ 88,765.38
Cost-based	$ 173,340.00	$ 173,340.00
Cost-based	$ 60,818.09	$ 60,818.09
Cost-based	$ 913,049.15	$ 913,049.15
Cost-based	$ 606,801.86	$ 606,801.86
Cost-based	$ 112,093.20	$ 112,093.20
Cost-based	$ 69,458.44	$ 69,458.44
Market-based [third-party services]; Cost-based [Administration]	$ 400,651.16	$ 400,651.16
Cost-based	$ 157,163.23	$ 157,163.23
Cost-based	$ 10,151.72	$ 10,151.72
:ce Level Agreement	**$ 2,475,750.99**	**$ 2,475,750.99**

ering and Settlement, Regualtory and Adminsitration, Meeting
were transferred to BPI on April 1, 2012

.evel Agreement with the City

ıe-Call system.

of the City's Brantford Power Department rather than BPI provided
ıis was a transaction internal to the City's operations.

ation

Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
	%	$
	33	$ 3,321.00
	33	
% of time contracted	33	
	90	$ 17,025.96
	5	
% of total assets	5	
	85	$ 3,459.68
	10	
Estimate of time	5	
	90	$ 133,664.04
	5	
% of total assets	5	
	90	$ 493,021.06
	10	
Estimate of time	0	
	90	$ 46,207.50
	5	
% of total assets	5	
	90	$ 173,340.00
	5	
% of total assets	5	
	70	See Row 82
	30	
% of time contracted	5	
	60	See Row 82
	35	
Estimate of time	5	
		$ 88,765.38
	90	$ 60,818.09
	5	
% of total assets	5	
	75	See Row 98
	20	
	5	
	95	See Row 98
	5	
	0	

	98.4	See Row 98
	1.6	
% of square footage utilized	0	
	90	See Row 98
	5	
% of total assets	5	
		$ 606,801.86
	90	$ 112,093.20
	5	
% of total assets	5	
	90	$ 69,458.44
	5	
% of total assets	5	
	90	See Row 101
	5	
% of total assets	5	
	N/A	See Row 101
Actual csts for materials and projects	N/A	
plus allocation of administrative costs	N/A	
		$ 913,049.15
	80	$ -
	10	
Estimate of time	10	

vided or received for the Historical (actuals), Bridge and Test years.

I and the City, costs were passed from the City of Brantford to the
up. The table above sets out the allocation percentages in place at that

Appendix 2-
Shared Services and Corpora

Year: 2013

Shared Servic

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Power Inc.	Mail Services
City of Brantford	Brantford Power Inc.	Insurance and Risk Management
City of Brantford	Brantford Power Inc.	Telephone Services
City of Brantford	Brantford Power Inc.	Treasury [Accounts Payables, Payroll]
City of Brantford	Brantford Power Inc.	Purchasing
City of Brantford	Brantford Power Inc.	IT Services
City of Brantford	Brantford Power Inc.	Facilities
City of Brantford	Brantford Power Inc.	Legal Services
City of Brantford	Brantford Power Inc.	Human Resources
City of Brantford	Brantford Power Inc.	Forestry
Brantford Power Inc.	City of Brantford	Street Light Maintenance
Brantford Power Inc.	Brantford Hydro Inc.	Sentinel Light Maintenance

Total - Shared Services that BPI continues to purchase in 2013 under renegotiated Ser

NOTES

Pricing methodologies and costs for services purchased from the C
Agreement effective January 1, 2013

Corporate Cost Allc

Name of Company		Service Offered
From	**To**	
City of Brantford	Brantford Power Inc.	Records Management
City of Brantford	Brantford Power Inc.	Mail Services
City of Brantford	Brantford Power Inc.	Insurance and Risk Management - Administration only
City of Brantford	Brantford Power Inc.	Telephone Services excluding out-of-pocket expenses

City of Brantford	Brantford Power Inc.	Treasury -Accounts Payables only
		Treasury - Payroll only
City of Brantford	Brantford Power Inc.	Purchasing
City of Brantford	Brantford Power Inc.	IT Services - Core Network Services
City of Brantford	Brantford Power Inc.	IT Services - Financial Information System Services
City of Brantford	Brantford Power Inc.	IT Services - Supervision
City of Brantford	Brantford Power Inc.	IT Services - Information Systems exclusive to BPI
City of Brantford	Brantford Power Inc.	Facilities - Administration only at 84 Market Street, 220 Colborne Street and 400 Grand River Avenue
City of Brantford	Brantford Power Inc.	Facilities - Repairs and Maintenance only - 84 Market Street
City of Brantford	Brantford Power Inc.	Facilities - Repairs and Maintenance only - 220 Colborne Street
City of Brantford	Brantford Power Inc.	Facilities - Repairs and Maintenance only - 400 Grand River Avenue
City of Brantford	Brantford Power Inc.	Facilities - Rent at all locations
City of Brantford	Brantford Power Inc.	Legal and Real Estate Services
City of Brantford	Brantford Power Inc.	Human Resources - Administration and Health and Safety Services
City of Brantford	Brantford Power Inc.	Human Resources - Employment Services and Labour Relations
City of Brantford	Brantford Power Inc.	Forestry
Brantford Power Inc.	City of Brantford	Street Light Maintenance
Brantford Power Inc.	Brantford Hydro Inc.	Sentinel Light Maintenance

Note:

1 **This appendix must be completed in relation to each service p**

File Number:	EB-2012-0109
Exhibit:	4
Tab:	
Schedule:	
Page:	32
Date:	July 17,2013

-N

ate Cost Allocatio

es

Pricing Methdology	Price for the Service	Cost for the Service
	$	$
Market-based	$ 17,000.00	Not available
Market-based	$ 14,927.00	Not available
Market-based [premiums], Cost-based [Administration]	$ 143,133.00	$ 143,133.00
Cost-based	$ 21,124.00	$ 21,124.00
Cost-based	$ 59,053.00	$ 59,053.00
Cost-based	$ 75,000.00	$ 75,000.00
Cost-based	$ 911,700.00	$ 911,700.00
Market-based [for rent]; Cost-based [Repairs and Maintenance; Administration]	$ 538,098.00	Not available
Cost-based	$ 55,000.00	$ 55,000.00
Cost-based	$ 64,639.00	$ 64,639.00
Market-based [third-party services]; Cost-based [Administration]	$ 472,409.00	$ 472,409.00
Cost-based	$ 150,000.00	$ 150,000.00
Cost-based	$ 10,000.00	$ 10,000.00

vice Level Agreement	**$ 2,372,083.00**

ity were renegotiated January 1, 2013 and set out in a new Service Level

ocation

Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
	%	$
Market-based	Not Applicable	
Market-based	Not Applicable	
Cost-based	6.15%	$ 15,654.00
Cost-based	15.11%	$ 16,124.00

Cost-based	14.40%	$ 48,718.00
Cost-based	4.08%	$ 10,335.00
Cost-based using # of hours of service provided	Not Applicable	
Cost-based	9%	
Cost-based	6%	
Cost-based	25%	$ 328,899.00
Cost-based	100%	$ 582,801.00
Cost-based	2.52%	$ 19,649.00
Cost-based	38.60%	$ 66,508.00
Cost-based	2.50%	$ 10,013.00
Cost-based	various	$ 105,307.00
Market-based	Not applicable	
Cost-based using # of hours of service provided	Not applicable	
Cost-based	4.08%	$ 39,639.00
Cost-based using # of hours of service provided	Not Applicable	
Market-based [third-party services]; Cost-based [Administration]	48%	$ 472,409.00
Cost-based using # of hours to provide service	Not applicable	
Cost-based using # of hours to provide service	Not applicable	

ɪrovided or received for the Historical (actuals), Bridge and Test years.

File Number:	EB-2012-0109
Exhibit:	5
Tab:	1
Schedule:	1
Page:	33
Date:	July 17,2013

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	49.3%		$34,331,469	5.88%	$2,018,471
2	Short-term Debt	4.00%	(1)	$2,785,515	4.47%	$124,513
3	**Total Debt**	53.3%		$37,116,983	5.77%	$2,142,984
	Equity					
4	Common Equity	46.7%		$32,520,884	8.57%	$2,787,040
5	Preferred Shares			$ -		$ -
6	**Total Equity**	46.7%		$32,520,884	8.57%	$2,787,040
7	**Total**	100.0%		$69,637,867	7.08%	$4,930,024

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and tl

Line No.	Particulars	Capitalization Ratio			Cost Rate
		Application			
		(%)		($)	(%)
	Debt				
1	Long-term Debt	52.7%		$37,462,433	5.40%
2	Short-term Debt	4.00%	(1)	$2,843,448	4.47%
3	**Total Debt**	56.7%		$40,305,881	5.34%
	Equity				
4	Common Equity	43.3%		$30,780,329	8.57%
5	Preferred Shares			$ -	
6	**Total Equity**	43.3%		$30,780,329	8.57%
7	**Total**	100.0%		$71,086,210	6.74%

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

EB-2012-0109
5
1
1
34
July 17,2013

he test year.

Return
($)
$2,023,990
$127,102
$2,151,092
$2,637,874
$ -
$2,637,874
$4,788,966

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and t

Line No.	Particulars	Capitalization Ratio			Cost Rate
		Application			
		(%)		($)	(%)
	Debt				
1	Long-term Debt	56.0%		$41,280,072	5.30%
2	Short-term Debt	4.00%	(1)	$2,948,577	4.47%
3	**Total Debt**	60.0%		$44,228,648	5.25%
	Equity				
4	Common Equity	40.00%		$29,485,766	8.57%
5	Preferred Shares			$ -	
6	**Total Equity**	40.0%		$29,485,766	8.57%
7	**Total**	100.0%		$73,714,414	6.58%

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

EB-2012-0109
5
1
1
35
July 17,2013

he test year.

Return
($)
$2,188,064
$131,801
$2,319,866
$2,526,930
$ -
$2,526,930
$4,846,796

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and tl

Line No.	Particulars	Capitalization Ratio			Cost Rate	
		Application				
		(%)		($)	(%)	
	Debt					
1	Long-term Debt	56.0%		$42,333,493	5.06%	
2	Short-term Debt	4.00%	(1)	$3,023,821	4.47%	
3	**Total Debt**	60.0%		$45,357,314	5.02%	
	Equity					
4	Common Equity	40.0%		$30,238,209	8.57%	
5	Preferred Shares			$ -		
6	**Total Equity**	40.0%		$30,238,209	8.57%	
7	**Total**	100.0%		$75,595,523	6.44%	

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

EB-2012-0109
5
1
1
36
July 17,2013

he test year.

Return
($)
$2,143,186
$135,165
$2,278,350
$2,591,415
$ -
$2,591,415
$4,869,765

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and tl

Line No.	Particulars	Capitalization Ratio			Cost Rate
		Application			
		(%)		($)	(%)
	Debt				
1	Long-term Debt	56.00%		$42,568,495	5.09%
2	Short-term Debt	4.00%	(1)	$3,040,607	4.47%
3	**Total Debt**	60.0%		$45,609,102	5.04%
	Equity				
4	Common Equity	40.00%		$30,406,068	8.57%
5	Preferred Shares			$ -	
6	**Total Equity**	40.0%		$30,406,068	8.57%
7	**Total**	100.0%		$76,015,169	6.45%

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

EB-2012-0109
5
1
1
37
July 17,2013

he test year.

Return
($)
$2,164,982
$135,915
$2,300,897
$2,605,800
$ -
$2,605,800
$4,906,697

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and tl

Line No.	Particulars	Capitalization Ratio			Cost Rate
		Application			
		(%)		($)	(%)
	Debt				
1	Long-term Debt	56.00%		$44,099,087	5.17%
2	Short-term Debt	4.00%	(1)	$3,149,935	2.07%
3	**Total Debt**	60.0%		$47,249,021	4.97%
	Equity				
4	Common Equity	40.00%		$31,499,348	8.98%
5	Preferred Shares			$ -	
6	**Total Equity**	40.0%		$31,499,348	8.98%
7	**Total**	100.0%		$78,748,369	6.57%

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

EB-2012-0109
5
1
1
38
July 17,2013

he test year.

Return
($)
$2,281,296
$65,204
$2,346,500
$2,828,641
$ -
$2,828,641
$5,175,141

File Number:	EB-2012-0109
Exhibit:	5
Tab:	1
Schedule:	1
Page:	39
Date:	July 17,2013

Appendix 2-OB
Debt Instruments

Appendix 2-C
Debt Instrume

This table must be completed for the required years of all his

Year 2009

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?
1	Promissory note	The Corporation of the City of Brantford	Affiliated	Fixed Rate
2	Powerline Municipal Transformer Station Borrowings	Royal Bank	Third-Party	Fixed Rate
3	Tier 2 Capital Project Borrowing	Royal Bank	Third-Party	Fixed Rate
4	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party	Fixed Rate
5	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party	Fixed Rate
6	Smart meter borrowings	Ontario Infrastructure & Lands Corporation	Third-Party	Fixed Rate
7				
8				
9				
10				
11				
12				
Total				

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board or*
3 Add more lines above row 12 if necessary.

File Number:	EB-2012-0109
Exhibit:	5
Tab:	1
Schedule:	1
Page:	40
Date:	July 17,2013

OE
ents

torical years, the bridge year and the test year.

Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
February 1, 2006	5	$ 24,189,168	6.25%	$1,511,823.00	
January 31, 2006	15	$ 5,061,000	4.71%	$ 238,373.10	
June 13, 2006	10	$ 909,000	4.97%	$ 45,177.30	
December 3, 2007	25	$ 2,318,871	5.14%	$ 119,189.98	
December 1, 2010	25	$ 2,400,000	0.95%	$ 22,800.00	
November 18, 2009	15	$ 1,451,000	1.75%	$ 25,392.50	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
		$ 36,329,039	0.05403	$1,962,755.88	

n the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009

Ap
Deb

This table must be completed for the required y

Year

Row	Description	Lender	Affiliated or Third-Party Debt?
1	Promissory note	The Corporation of the City of Brantford	Affiliated
2	Powerline Municipal Transformer Station Borrowings	Royal Bank	Third-Party
3	Tier 2 Capital Project Borrowing	Royal Bank	Third-Party
4	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
5	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
6	Smart meter borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
7			
8			
9			
10			
11			
12			
Total			

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of*
3 Add more lines above row 12 if necessary.

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

pendix 2-OB
t Instruments

/ears of all historical years, the bridge year and the test year.

2010

Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
Fixed Rate	February 1, 2006	5	$ 24,189,168	6.25%	$1,511,823.00
Fixed Rate	January 31, 2006	15	$ 4,724,000	4.71%	$ 222,500.40
Fixed Rate	June 13, 2006	10	$ 801,000	4.97%	$ 39,809.70
Fixed Rate	December 3, 2007	25	$ 2,264,325	5.14%	$ 116,386.29
Fixed Rate	December 1, 2010	40	$ 4,800,000	4.95%	$ 237,600.00
Fixed Rate	November 18, 2009	3	$ 4,751,000	1.54%	$ 73,165.40
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
			$ 41,529,493	0.05301	$2,201,284.79

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EB-2012-0109
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July 17,2013

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This table must be completed for the required y

Year

Row	Description	Lender	Affiliated or Third-Party Debt?
1	Promissory note	The Corporation of the City of Brantford	Affiliated
2	Powerline Municipal Transformer Station Borrowings	Royal Bank	Third-Party
3	Tier 2 Capital Project Borrowing	Royal Bank	Third-Party
4	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
5	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
6	Smart meter borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
7			
8			
9			
10			
11			
12			
Total			

Notes

1. If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of*
3. Add more lines above row 12 if necessary.

pendix 2-OB
t Instruments

/ears of all historical years, the bridge year and the test year.

2011

Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
Fixed Rate	February 1, 2011	5	$ 24,189,168	5.87%	$1,419,904.16
Fixed Rate	January 31, 2006	15	$ 4,369,000	4.71%	$ 205,779.90
Fixed Rate	June 13, 2006	10	$ 686,000	4.97%	$ 34,094.20
Fixed Rate	December 3, 2007	25	$ 2,206,939	5.14%	$ 113,436.65
Fixed Rate	December 1, 2010	40	$ 4,760,374	4.95%	$ 235,638.51
Fixed Rate	November 18, 2009	3	$ 5,301,000	1.75%	$ 92,767.50
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
			$ 41,512,481	0.05063	$2,101,620.91

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the Board on the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009

EB-2012-0109
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42
July 17,2013

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Year

Row	Description	Lender	Affiliated or Third-Party Debt?
1	Promissory note	The Corporation of the City of Brantford	Affiliated
2	Powerline Municipal Transformer Station Bo	Royal Bank	Third-Party
3	Tier 2 Capital Project Borrowing	Royal Bank	Third-Party
4	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
5	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
6	Smart meter borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
7	Smart meter borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
8	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
9			
10			
11			
12			
Total			

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of*
3 Add more lines above row 12 if necessary.

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

pendix 2-OB
t Instruments

/ears of all historical years, the bridge year and the test year.

2012

Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
Fixed Rate	February 1, 2011	5	$ 24,189,168	5.87%	$1,419,904.16
Fixed Rate	January 31, 2006	15	$ 3,994,000	4.71%	$ 188,117.40
Fixed Rate	June 13, 2006	10	$ 564,000	4.97%	$ 28,030.80
Fixed Rate	December 3, 2007	25	$ 2,146,565	5.14%	$ 110,333.44
Fixed Rate	December 1, 2010	40	$ 4,718,762	4.95%	$ 233,578.72
Fixed Rate	November 18, 2009	15	$ 4,378,708	1.75%	$ 76,627.40
Fixed Rate	November 18, 2009	15	$ 1,152,292	3.46%	$ 39,869.29
Fixed Rate	December 3, 2012	30	$ 333,333	3.90%	$ 13,000.00
					$ -
					$ -
					$ -
					$ -
			$ 41,476,828	0.05086	$2,109,461.21

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the Board on the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009

EB-2012-0109
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1
43
July 17,2013

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Year

Row	Description	Lender	Affiliated or Third-Party Debt?
1	Promissory note	The Corporation of the City of Brantford	Affiliated
2	Powerline Municipal Transformer Station Bo	Royal Bank	Third-Party
3	Tier 2 Capital Project Borrowing	Royal Bank	Third-Party
4	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
5	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
6	Smart meter borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
7	General borrowings	Ontario Infrastructure & Lands Corporation	Third-Party
8			
9			
10			
11			
12			
Total			

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of*
3 Add more lines above row 12 if necessary.

File Number:
Exhibit:
Tab:
Schedule:
Page:

Date:

pendix 2-OB
t Instruments

/ears of all historical years, the bridge year and the test year.

2013

Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
Fixed Rate	February 1, 2011	5	$ 24,189,168	5.87%	$1,419,904.16
Fixed Rate	January 31, 2006	15	$ 3,596,000	4.71%	$ 169,371.60
Fixed Rate	June 13, 2006	10	$ 435,000	4.97%	$ 21,619.50
Fixed Rate	December 3, 2007	25	$ 2,083,048	5.14%	$ 107,068.67
Fixed Rate	December 1, 2010	40	$ 4,675,065	4.95%	$ 231,415.72
Fixed Rate	November 18, 2009	15	$ 5,245,003	3.46%	$ 181,477.10
Fixed Rate	December 3, 2012	30	$ 3,932,125	3.90%	$ 153,352.88
					$ -
					$ -
					$ -
					$ -
					$ -
			$ 44,155,409	0.05173	$2,284,209.63

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the Board on the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009

EB-2012-0109
5
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44
July 17,2013

File Number:	EB-2012-0109
Exhibit:	7
Tab:	1
Schedule:	2
Page:	45
Date:	July 17,2013

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from BCP Motion Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$9,924,666	58.80%	$ 10,821,186.51	60.57%
GS < 50 kW	$1,955,571	11.59%	$ 2,088,907.19	11.69%
GS > 50 kW, if applicable	$3,295,266	19.52%	$ 4,357,783.64	24.39%
Large User, if applicable	$240,015	1.42%		0.00%
Street Lighting	$906,296	5.37%	$ 137,887.72	0.77%
Sentinel Lighting	$72,502	0.43%	$ 84,145.69	0.47%
Unmetered Scattered Load (USL)	$77,698	0.46%	$ 79,639.49	0.45%
Standby	$104,404	0.62%		0.00%
Embedded distributor class	$303,456	1.80%	$ 295,050.62	1.65%
Total	$ 16,879,874	100.00%	$ 17,864,601	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

1.092164806

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C L.F. X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$8,739,824	$ 9,545,328.38	$ 9,545,328	$ 826,242
GS < 50 kW	$1,456,779	$ 1,591,043.21	$ 1,592,778	$ 119,559
GS > 50 kW, if applicable	$4,563,334	$ 4,983,912.97	$ 4,983,913	$ 182,071
Street Lighting	$144,395	$ 157,703.45	$ 157,703	$ 7,470
Sentinel Lighting	$32,766	$ 35,786.12	$ 60,496	$ 6,821
Unmetered Scattered Load (USL)	$73,750	$ 80,546.80	$ 80,547	$ 6,622
Embedded distributor class	$283,047	$ 309,133.52	$ 282,689	$ 12,362
Total	$ 15,293,896	$ 16,703,454.45	$ 16,703,454.42	$ 1,161,146

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2010	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	95.37	95.85	95.85	85 - 115
GS < 50 kW	89.63	81.89	81.97	80 - 120
GS > 50 kW, if applicable	124.12	118.55	118.55	80 - 120
Street Lighting	70.17	119.79	119.79	70 - 120
Sentinel Lighting	70.00	50.63	80.00	80 - 120
Unmetered Scattered Load (USL)	111.06	109.45	109.45	80 - 120
Embedded distributor class		108.96	100.00	

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants that have had

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios 2013	2014	2015	Policy Range
	%	%	%	%
Residential	95.85			85 - 115
GS < 50 kW	81.97			80 - 120
GS > 50 kW, if applicable	118.55			80 - 120
Street Lighting	119.79			70 - 120
Sentinel Lighting	80.00			80 - 120
Unmetered Scattered Load (USL)	109.45			80 - 120
Embedded distributor class	100.00			

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2012 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2013 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2013 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

File Number:	EB-2012-0109
Exhibit:	7
Tab:	
Schedule:	
Page:	46
Date:	

Appendix 2-Q
Cost of Serving Embedded Distributor(s)

To be completed by Host Distributors*
(Not required if Host Distributor has an Embedded Distributor rate class, i.e. a separate row in Appendix 2-P.)

Proposed Rate Class for Billing

Host's Distribution Facilities used by Embedded Distributor(s)

(1)	(2)	(3)	(4)	(5)	(6) = '(3) + (4)
Asset Class	**Total OM&A costs asociated with asset class**	**Original cost of asset class**	**Accumulated amortization of asset class**	**Annual amortization of asset class**	**Net Book Value of asset class**
Totals for Host Distributor:	($)	($)	($)	($)	
Distribution Stations					$ -
Low Voltage Line					$ -
LV Line category # 2 (if applcable)					$ -
TS (owned by host)					$ -
add rows if necessary...					$ -
					$ -
					$ -

(1)	(7)	(8)	(9)	(10)	(11)
Asset Class	**Total line length or station capacity in asset class**	**Line length or capacity required to provide LV service to Embedded Distributor(s)**	**Annual total demand on station/line providing LV services (sum of 12 monthly peaks)**	**Annual billed Embedded Distributor demand on station/line providing LV services**	**Embedded Distributor(s)' Responsibility Share**
Embedded Distributor's share:	kW or kVa; km	kW or kVA; km	kW or kVA	kW or kVA	percent
Distribution Stations					0.00%
Low Voltage Line					0.00%
LV Line # 2 (if applicable)					0.00%
TS (owned by host)					0.00%
add rows if necessary					0.00%

(1)	(12)	(12a)	(13)	(14)	(15)	(16)
Asset Class	**Return on Assets used to Provide LV services**	**Taxes/PILs**	**Annual amortization on assets used to provide LV services**	**OM&A costs with burden associated with assets used to provide LV services**	**Total annual cost associated with assets used to provide LV services**	**Monthly cost associated with the delivery of LV services**
	($)	($)	($)	($)	($)	$/kW or $/kVA
Distribution Stations	$ -	$ -	$ -	$ -	$ -	0.00
Low Voltage Line	$ -	$ -	$ -	$ -	$ -	0.00
LV Line # 2 (if applicable)	$ -	$ -	$ -	$ -	$ -	0.00
TS (owned by host)	$ -	$ -	$ -	$ -	$ -	0.00
add rows if necessary	$ -	$ -	$ -	$ -	$ -	0.00
Total					**$ -**	**0.00**

(17)	(18) Capital Structure (%)	(19) Cost Rate (%)	(20)	(21) (%)
Long-Term Debt			Weighted Average Cost of Capital	0.00%
Short-term Debt				
Common Equity			Tax/PILs Rate	
Preferred Shares				
Total	0.00%		Working Capital Allowance Factor	

File Number:	EB-2012-0109
Exhibit:	8
Tab:	1
Schedule:	1
Page:	47
Date:	July 17,2013

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2007	**2008**	**2009**	**2010**	**2011**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	1,043,014,997	1,013,423,330	940,830,205	950,759,113	944,902,732	978,586,075
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1,038,354,233	1,008,890,381	936,617,083	946,540,017	940,754,877	974,231,318
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	0	0	0	0	0	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	1,038,354,233	1,008,890,381	936,617,083	946,540,017	940,754,877	974,231,318
D	"Retail" kWh delivered by distributor	1,004,831,701	977,884,255	912,366,781	917,169,662	915,803,475	945,611,175
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	0	0	0	0	0	-
F	Net "Retail" kWh delivered by distributor = **D - E**	1004831701	977884255	912366781	917169662	915803475	945,611,175
G	Loss Factor in Distributor's system = **C / F**	1.0334	1.0317	1.0266	1.0320	1.0272	1.0303
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0380	1.0364	1.0312	1.0367	1.0319	1.0349

Notes

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to an actual or virtual meter at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

G and I These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

File Number:	EB-2012-0109
Exhibit:	9
Tab:	
Schedule:	
Page:	48
Date:	July 17,2013

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009		$ 953,530	$ 359,800		$ 593,730		$ 593,730
2010		$ 3,978,550	$ 1,521,728		$ 2,456,822	$ 3,781	$ 2,453,041
2011		$ 342,720	$ 150,854		$ 191,866	$ 1,446	$ 190,420
2012	(1)				$ -		$ -

Notes:

(1) *For 2012, please indicate whether the amounts provided are on a forecast or actual basis.*

Some distributors have transferred the cost of stranded meters from Account 1860 - Meters to "Sub-account Stranded Meter Costs of Account 1555", while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen. please provide the information under either of the two scenarios (A and B below), as applicable.

Scenario A: *If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555, the above table should be completed and the following information should be provided.*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, which were transferred to this sub-account as of December 31, 2010.

3 A statement as to whether or not, since transferring the removed stranded meter costs to the sub-account, the recording of depreciation expenses was continued in order to reduce the net book value through accumulated depreciation. If so, the total depreciation expense amount for the period from the time the costs for the stranded meters were transferred to the sub-account to December 31, 2010 should be provided.

If no depreciation expenses were recorded to reduce the net book value of stranded meter costs through accumulated depreciation, the total depreciation expense amount that would have been applicable from the time that the stranded meter costs were transferred to the sub-account of Account 1555 to December 31, 2010 should be provided. In addition, the following information should be provided:

a) Whether or not carrying charges were recorded for the stranded meter cost balances in the sub-account, and if so, the total carrying charges recorded to December 31, 2010.

b) The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when the smart meters will have been fully deployed (e.g., as of December 31, 2010). If the smart meters have been fully deployed, the actual amount should be provided.

c) A description as to how the applicant intends to recover in rates the remaining costs for stranded meters, including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

Scenario B: *If the stranded meter costs remained recorded in Account 1860, the above table should be completed and the following information should be provided:*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2010.

3 A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2010.

4 If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2010.

5 The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

6 A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

Distributors should also provide the Net Book Value per class of meter as of December 31, 2010 as well as the number of meters that were removed / stranded. In preparing this information, distributors should review the Board's letter of January 16, 2007 *Stranded Meter Costs Related to the Installation of Smart Meters* which stated that records were to be kept of the type and number of each meter to support the stranded meter costs.

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	49
Date:	

Appendix 2-T
Deferred PILs Account 1592 Balances

The following table should be completed based on the information requested below, in accordance with the notes following the table. An explanation should be provided for any blank entries.

Tax Item	Principal as of December 31, 20XX
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562	
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2006	
Capital Cost Allowance class changes from 2006 EDR application for 2007	
Capital Cost Allowance class changes from 2006 EDR application for 2008	
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2011	
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.	
Insert description of additional item(s) and new rows if needed.	
Total	$ -

Notes:

1. Revise the deferral and variance account continuity schedule to include account 1592 as a group 2 account and enter all relevant information for transactions, adjustments, etc., for all relevant years.
2. Describe each type of tax item that has been recorded in account 1592.
3. Provide the calculations that show how each item was determined and provide any pertinent supporting evidence and documentation.
4. Please state whether or not the applicant followed the guidance provided in the FAQ of July 2007. If not, please provide an explanation.
5. Identify the account balance as of December 31, 2011 as per the 2011 Audited Financial Statements. Identify the account balance as of December 31, 2011 as per the April 2012 2.1.7 RRR filing to the Board. Provide a reconciliation if the balances provided are not identical to each other and to the total shown on the continuity schedule.
6. Complete the above table based on the answers to the previous. Add rows as required to complete the analysis in an informative manner. Please provide the completed table as a working Excel spreadsheet.

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	50
Date:	

Appendix 2-U
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Carrying Charges to Dec 31, 2011	Total Audited Actual Costs to Dec 31, 2011	RRR 2.1.7 Balance 31-Dec-11	Variance [2]	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees					$ -			
professional legal fees					$ -			
salaries, wages and benefits of staff added to support the transition to IFRS					$ -			
associated staff training and development costs					$ -			
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion					$ -			
					$ -			
					$ -			
					$ -			
					$ -			
					$ -			
					$ -			
					$ -			
Insert description of additional item(s) and new rows if needed.					$ -			
Total	$ -	$ -	$ -	$ -	$ -		$ -	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 Applicants are to provide an explanation of material variances in evidence

File Number:	EB-2012-0109
Exhibit:	8
Tab:	1
Schedule:	7
Page:	51
Date:	July 17,2013

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	35,242.24	35,699.33	35,364	280,913,502		$ 12.52	$ 0.0151		$ 9,554,838.17	$ 9,545,328		$ 9,545,328	-$ 9,510
GS < 50 kW	Customers	2,687.52	2,718.39	2,764	97,535,297		$ 27.13	$ 0.0071		$ 1,592,379.21	$ 1,592,778	$ 126	$ 1,592,904	$ 525
GS > 50 to 4,999 kW	Customers	421.10	424.23	420	531,977,718	1,354,270	$ 320.78		$ 2.8142	$ 5,427,067.93	$ 4,983,913	$ 443,111	$ 5,427,024	-$ 44
Large Use				-						$ -			$ -	$ -
Streetlighting	Connections	10,238.03	10,458.73	10,355	7,553,004	23,455	$ 0.71		$ 2.9627	$ 157,714.63	$ 157,703		$ 157,703	-$ 11
Sentinel Lighting	Connections	641.72	657.83	635	443,490	1,356	$ 4.28		$ 20.5359	$ 60,470.08	$ 60,496		$ 60,496	$ 26
Unmetered Scattered Load	Customers	438.13	431.36	437	1,454,727		$ 13.17	$ 0.0079		$ 80,591.86	$ 80,547		$ 80,547	-$ 45
Standby Power	Customers			-						$ -			$ -	$ -
Embedded Distributor Class	Customers	1.00	1.00	3		155,806	$ 293.34		$ 1.7466	$ 282,690.49	$ 282,689		$ 282,689	-$ 2
etc.				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$ 17,155,752.37	$ 16,703,454	$ 443,238	$ 17,146,692	-$ 9,060

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

File Number:	EB-2012-0109
Exhibit:	Interrgatory Response
Tab:	
Schedule:	
Page:	
Date:	July 17 2013
Revised:	October 23 2013

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)

	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		$ 11.4600	1	$ 11.46	$ 12.6300	1	$ 12.63	$ 1.17	10.21%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Disposition Rate Rider			1	$ -	-$ 0.4600	1	-$ 0.46	-$ 0.46	
Smart Metering Entity Charge			1	$ -	$ 0.7880	1	$ 0.79	$ 0.79	
Stranded Meter Recovery Rate Rider			1	$ -	$ 1.5100	1	$ 1.51	$ 1.51	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0138	800	$ 11.04	$ 0.0152	800	$ 12.16	$ 1.12	10.14%
			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider		$ 0.0013	800	$ 1.04	$ 0.0003	800	$ 0.21	-$ 0.83	-79.41%
Tax change		-$ 0.0005	800	-$ 0.40		800	$ -	$ 0.40	-100.00%
LRAMVA Rate Rider			800	$ -	$ 0.0001	800	$ 0.08	$ 0.08	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 23.14			$ 26.92	**$ 3.78**	**16.34%**
Deferral/Variance Account Disposition Rate Rider		-$ 0.0070	800	-$ 5.60	-$ 0.0040	800	-$ 3.18	$ 2.42	-43.23%
Global Adjustment - Non RPP			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge			800	$ -		800	$ -	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.54**			**$ 23.74**	**$ 6.20**	**35.37%**
RTSR - Network		$ 0.0080	834	$ 6.67	$ 0.0086	828	$ 7.11	$ 0.44	6.56%
RTSR - Line and Transformation Connection		$ 0.0055	834	$ 4.58	$ 0.0055	828	$ 4.56	-$ 0.02	-0.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28.79**			**$ 35.41**	**$ 6.62**	**22.98%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	834	$ 4.33	$ 0.0044	828	$ 3.64	-$ 0.69	-15.96%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	834	$ 0.92	$ 0.0012	828	$ 0.99	$ 0.08	8.35%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	834	$ 5.84	$ 0.0070	828	$ 5.80	-$ 0.04	-0.68%
Energy - RPP - Tier 1		$ 0.0780	834	$ 65.02	$ 0.0780	828	$ 64.58	-$ 0.44	-0.68%
Energy - RPP - Tier 2		$ 0.0910	0	$ -	$ 0.0910	0	$ -	$ -	
TOU - Off Peak		$ 0.0670	534	$ 35.74	$ 0.0670	530	$ 35.50	-$ 0.24	-0.68%
TOU - Mid Peak		$ 0.1040	150	$ 15.60	$ 0.1040	149	$ 15.50	-$ 0.11	-0.68%
TOU - On Peak		$ 0.1240	150	$ 18.61	$ 0.1240	149	$ 18.48	-$ 0.13	-0.68%
Total Bill on RPP (before Taxes)				**$ 105.15**			**$ 110.67**	**$ 5.52**	**5.25%**
HST		13%		$ 13.67	13%		$ 14.39	$ 0.72	5.25%
Total Bill (including HST)				$ 118.82			$ 125.06	$ 6.24	5.25%
Ontario Clean Energy Benefit [1]				-$ 11.88			-$ 12.51	-$ 0.63	5.30%
Total Bill on RPP (including OCEB)				**$ 106.94**			**$ 112.55**	**$ 5.61**	**5.24%**
Total Bill on TOU (before Taxes)				**$ 110.09**			**$ 115.57**	**$ 5.48**	**4.98%**
HST		13%		$ 14.31	13%		$ 15.02	$ 0.71	4.98%
Total Bill (including HST)				$ 124.40			$ 130.59	$ 6.20	4.98%
Ontario Clean Energy Benefit [1]				-$ 12.44			-$ 13.06	-$ 0.62	4.98%
Total Bill on TOU (including OCEB)				**$ 111.96**			**$ 117.53**	**$ 5.58**	**4.98%**
Loss Factor (%)		4.20%			3.49%				

[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.

File Number:	EB-2012-0109
Exhibit:	Interrgatory Response
Tab:	
Schedule:	
Page:	
Date:	July 17 2013
Revised:	October 23 2013

Appendix 2-W
Bill Impacts

Customer Class: **GS<50**

Consumption 2000 **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge		$ 24.8100	1	$ 24.81	$ 27.3500	1	$ 27.35	$ 2.54	10.24%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Disposition Rate Rider			1	$ -	$ 2.7800	1	$ 2.78	$ 2.78	
Smart Metering Entity Charge			1	$ -	$ 0.7880	1	$ 0.79	$ 0.79	
Stranded Meter Recovery Rate Rider			1	$ -	$ 4.5300	1	$ 4.53	$ 4.53	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0065	2000	$ 13.00	$ 0.0072	2000	$ 14.40	$ 1.40	10.77%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider		$ 0.0004	2000	$ 0.80	$ 0.0002	2000	$ 0.45	-$ 0.35	-43.50%
Tax change		-$ 0.0002	2000	-$ 0.40		2000	$ -	$ 0.40	-100.00%
LRAMVA Rate Rider			2000	$ -	$ 0.0001	2000	$ 0.20	$ 0.20	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 38.21			$ 50.50	**$ 12.29**	**32.16%**
Deferral/Variance Account Disposition Rate Rider		-$ 0.0052	2000	-$ 10.40	-$ 0.0040	2000	-$ 7.95	$ 2.45	-23.58%
Global Adjustment - Non RPP			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge			2000	$ -		2000	$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 27.81**			**$ 42.55**	**$ 14.74**	**53.01%**
RTSR - Network		$ 0.0072	2084	$ 15.00	$ 0.0077	2070	$ 15.99	$ 0.98	6.56%
RTSR - Line and Transformation Connection		$ 0.0048	2084	$ 10.00	$ 0.0048	2070	$ 9.95	-$ 0.05	-0.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 52.82**			**$ 68.49**	**$ 15.67**	**29.68%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	2084	$ 10.84	$ 0.0044	2070	$ 9.11	-$ 1.73	-15.96%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	2084	$ 2.29	$ 0.0012	2070	$ 2.48	$ 0.19	8.35%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	2084	$ 14.59	$ 0.0070	2070	$ 14.49	-$ 0.10	-0.68%
Energy - RPP - Tier 1		$ 0.0780	1000	$ 78.00	$ 0.0780	1000	$ 78.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0910	1084	$ 98.64	$ 0.0910	1070	$ 97.35	-$ 1.29	-1.31%
TOU - Off Peak		$ 0.0670	1334	$ 89.36	$ 0.0670	1325	$ 88.75	-$ 0.61	-0.68%
TOU - Mid Peak		$ 0.1040	375	$ 39.01	$ 0.1040	373	$ 38.75	-$ 0.27	-0.68%
TOU - On Peak		$ 0.1240	375	$ 46.51	$ 0.1240	373	$ 46.20	-$ 0.32	-0.68%
Total Bill on RPP (before Taxes)				**$ 257.43**			**$ 270.17**	**$ 12.74**	**4.95%**
HST		13%		$ 33.47	13%		$ 35.12	$ 1.66	4.95%
Total Bill (including HST)				$ 290.89			$ 305.30	$ 14.40	4.95%
Ontario Clean Energy Benefit [1]				-$ 29.09			-$ 30.53	-$ 1.44	4.95%
Total Bill on RPP (including OCEB)				**$ 261.80**			**$ 274.77**	**$ 12.96**	**4.95%**
Total Bill on TOU (before Taxes)				**$ 255.67**			**$ 268.52**	**$ 12.84**	**5.02%**
HST		13%		$ 33.24	13%		$ 34.91	$ 1.67	5.02%
Total Bill (including HST)				$ 288.91			$ 303.43	$ 14.51	5.02%
Ontario Clean Energy Benefit [1]				-$ 28.89			-$ 30.34	-$ 1.45	5.02%
Total Bill on TOU (including OCEB)				**$ 260.02**			**$ 273.09**	**$ 13.06**	**5.02%**

Loss Factor (%)	4.20%	3.49%

[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.

File Number:	EB-2012-0109
Exhibit:	Interrgatory Response
Tab:	
Schedule:	
Page:	
Date:	July 17 2013
Revised:	October 23 2013

Appendix 2-W
Bill Impacts

Customer Class: **GS>50**

Consumption 100 kW
Consumption 39,339 kWh

○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 293.7100	1	$ 293.71	$ 323.6200	1	$ 323.62	$ 29.91	10.18%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Recovery			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.6043	100	$ 260.43	$ 2.8356	100	$ 283.56	$ 23.13	8.88%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0633	100	$ 6.33	$ 0.0159	100	$ 1.59	-$ 4.74	-74.88%
Tax change	per kW	-$ 0.0609	100	-$ 6.09		100	$ -	$ 6.09	-100.00%
LRAMVA Rate Rider	per kW			$ -	$ 0.0057	100	$ 0.57	$ 0.57	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Sub-Total A				$ 554.38			$ 609.34	**$ 54.96**	**9.91%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.8203	100	-$ 182.03	-$ 1.5609	100	-$ 156.09	$ 25.94	-14.25%
Global Adjustment - Non RPP	per kWh	-$ 0.5790	100	-$ 57.90	$ 0.7203	100	$ 72.03	$ 129.93	-224.40%
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Low Voltage Service Charge				$ -		0	$ -	$ -	
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 314.45**			**$ 525.27**	**$ 210.82**	**67.05%**
RTSR - Network	per kW	$ 2.4601	104	$ 256.34	$ 2.6394	103.49	$ 273.15	$ 16.81	6.56%
RTSR - Line and Transformation Connection	per kW	$ 1.6398	104	$ 170.87	$ 1.6423	103.49	$ 169.96	-$ 0.90	-0.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 741.66**			**$ 968.39**	**$ 226.73**	**30.57%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	40991	$ 213.15	$ 0.0044	40711.9	$ 179.13	-$ 34.02	-15.96%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	40991	$ 45.09	$ 0.0012	40711.9	$ 48.85	$ 3.76	8.35%
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	40991	$ 286.94	$ 0.0070	40711.9	$ 284.98	-$ 1.96	-0.68%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
Energy - COP		$0.08545	40991	$ 3,502.70	$0.08545	40711.9	$ 3,478.83	-$ 23.87	-0.68%
Total Bill on RPP (before Taxes)				**$ 1,287.09**			**$ 1,481.61**	**$ 194.52**	**15.11%**
HST		13%		$ 167.32	13%		$ 192.61	$ 25.29	15.11%
Total Bill (including HST)				$ 1,454.42			$ 1,674.22	$ 219.81	15.11%
Ontario Clean Energy Benefit [1]				-$ 145.44			-$ 167.42	-$ 21.98	15.11%
Total Bill on RPP (including OCEB)				**$ 1,308.98**			**$ 1,506.80**	**$ 197.83**	**15.11%**
Total Bill				**$ 4,789.79**			**$ 4,960.45**	**$ 170.65**	**3.56%**
HST		13%		$ 622.67	13%		$ 644.86	$ 22.18	3.56%
Total Bill (including HST)				$ 5,412.47			$ 5,605.31	$ 192.84	3.56%
Ontario Clean Energy Benefit [1]				-$ 541.25			-$ 560.53	-$ 19.28	3.56%
Total Bill on TOU (including OCEB)				**$ 4,871.22**			**$ 5,044.78**	**$ 173.56**	**3.56%**

Loss Factor (%) 4.20% 3.49%

[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.

File Number:	EB-2012-0109
Exhibit:	Interrgatory Response
Tab:	
Schedule:	
Page:	
Date:	July 17 2013
Revised:	October 23 2013

Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lights**

Consumption 1 kW ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption 150 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 2.3200	1	$ 2.32	$ 4.2436	1	$ 4.24	$ 1.92	82.91%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Recovery			1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 11.1228	1	$ 11.12	$ 20.3453	1	$ 20.35	$ 9.22	82.92%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1	$ -	$ -	1	$ -	$ -	
Tax change	per kW	-$ 0.3971	1	-$ 0.40	$ -	1	$ -	$ 0.40	-100.00%
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Sub-Total A				$ 13.05			$ 24.59	**$ 11.54**	**88.48%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 4.1579	1	-$ 4.16	-$ 1.2995	1	-$ 1.30	$ 2.86	-68.75%
Global Adjustment - Non RPP	per kW	-$ 0.4410	1	-$ 0.44	$ 0.5996	1	$ 0.60	$ 1.04	-235.97%
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Low Voltage Service Charge				$ -		0	$ -	$ -	
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8.45**			**$ 23.89**	**$ 15.44**	**182.82%**
RTSR - Network	per kW	$ 2.2973	1	$ 2.39	$ 2.4647	1.0349	$ 2.55	$ 0.16	6.56%
RTSR - Line and Transformation Connection	per kW	$ 1.5315	1	$ 1.60	$ 1.5339	1.0349	$ 1.59	-$ 0.01	-0.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 12.44**			**$ 28.03**	**$ 15.59**	**125.36%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	156	$ 0.81	$ 0.0044	155	$ 0.68	-$ 0.13	-15.96%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	156	$ 0.17	$ 0.0012	155	$ 0.19	$ 0.01	8.35%
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	156	$ 1.09	$ 0.0070	155	$ 1.09	-$ 0.01	-0.68%
Energy - RPP - Tier 1		$ 0.0740	0	$ -	$ 0.0740	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
Energy - COP		$ 0.0855	156	$ 13.36	$ 0.0855	155	$ 13.26	-$ 0.09	-0.68%
Total Bill on RPP (before Taxes)				**$ 14.77**			**$ 30.23**	**$ 15.47**	**104.76%**
HST		13%		$ 1.92	13%		$ 3.93	$ 2.01	104.76%
Total Bill (including HST)				$ 16.68			$ 34.16	$ 17.48	104.76%
Ontario Clean Energy Benefit [1]				-$ 1.67			-$ 3.42	-$ 1.75	104.79%
Total Bill on RPP (including OCEB)				**$ 15.01**			**$ 30.74**	**$ 15.73**	**104.76%**
Total Bill Impact				**$ 28.12**			**$ 43.50**	**$ 15.38**	**54.68%**
HST		13%		$ 3.66	13%		$ 5.65	$ 2.00	54.68%
Total Bill (including HST)				$ 31.78			$ 49.15	$ 17.38	54.68%
Ontario Clean Energy Benefit [1]				-$ 3.18			-$ 4.92	-$ 1.74	54.72%
Total Bill on TOU (including OCEB)				**$ 28.60**			**$ 44.23**	**$ 15.64**	**54.68%**

Loss Factor (%)	4.20%		3.49%

[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.

File Number:	EB-2012-0109
Exhibit:	Interrgatory Response
Tab:	
Schedule:	
Page:	
Date:	July 17 2013
Revised:	October 23 2013

Appendix 2-W
Bill Impacts

Customer Class: **Street lights**

Consumption 1 kW
Consumption 322 kWh

○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 0.6500	1	$ 0.65	$ 0.71	1	$ 0.71	$ 0.06	9.69%
Smart Meter Rate Adder	Monthly		1	$ -	$ -	1	$ -	$ -	
Stranded Meter Recovery			1	$ -	$ -	1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.7127	1	$ 2.71	$ 2.9755	1	$ 2.98	$ 0.26	9.69%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1	$ -	$ -	1	$ -	$ -	
Tax change	per kW	-$ 0.0984	1	-$ 0.10	$ -	1	$ -	$ 0.10	-100.00%
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Sub-Total A				$ 3.26			$ 3.69	**$ 0.42**	**13.00%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.8739	1	-$ 1.87	-$ 1.2796	1	-$ 1.28	$ 0.59	-31.72%
Global Adjustment - Non RPP	per kW	-$ 0.4810	1	-$ 0.48	$ 0.5904	1	$ 0.59	$ 1.07	-222.75%
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Low Voltage Service Charge				$ -		0	$ -	$ -	
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 0.91**			**$ 3.00**	**$ 2.09**	**229.82%**
RTSR - Network	per kW	$ 2.2708	1	$ 2.37	$ 2.4363	1.0349	$ 2.52	$ 0.16	6.56%
RTSR - Line and Transformation Connection	per kW	$ 1.5138	1	$ 1.58	$ 1.5161	1.0349	$ 1.57	-$ 0.01	-0.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 4.85**			**$ 7.09**	**$ 2.24**	**46.09%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	336	$ 1.74	$ 0.0044	333	$ 1.47	-$ 0.28	-15.96%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	336	$ 0.37	$ 0.0012	333	$ 0.40	$ 0.03	8.35%
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	336	$ 2.35	$ 0.0070	333	$ 2.33	-$ 0.02	-0.68%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
Energy - COP		$0.08545	336	$ 28.67	$0.08545	333	$ 28.48	-$ 0.20	-0.68%
Total Bill on RPP (before Taxes)				**$ 9.57**			**$ 11.54**	**$ 1.97**	**20.63%**
HST		13%		$ 1.24	13%		$ 1.50	$ 0.26	20.63%
Total Bill (including HST)				$ 10.81			$ 13.04	$ 2.23	20.63%
Ontario Clean Energy Benefit [1]				-$ 1.08			-$ 1.30	-$ 0.22	20.37%
Total Bill on RPP (including OCEB)				**$ 9.73**			**$ 11.74**	**$ 2.01**	**20.66%**
Total Bill				**$ 38.24**			**$ 40.01**	**$ 1.78**	**4.65%**
HST		13%		$ 4.97	13%		$ 5.20	$ 0.23	4.65%
Total Bill (including HST)				$ 43.21			$ 45.22	$ 2.01	4.65%
Ontario Clean Energy Benefit [1]				-$ 4.32			-$ 4.52	-$ 0.20	4.63%
Total Bill on TOU (including OCEB)				**$ 38.89**			**$ 40.70**	**$ 1.81**	**4.65%**

Loss Factor (%) 4.20% 3.49%

[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.

File Number:	EB-2012-0109
Exhibit:	Interrgatory Response
Tab:	
Schedule:	
Page:	
Date:	July 17 2013
Revised:	October 23 2013

Appendix 2-W
Bill Impacts

Customer Class: **USL**

Consumption 0 **kW** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption 150 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 12.0600	1	$ 12.06	$ 13.2880	1	$ 13.29	$ 1.23	10.18%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Stranded Meter Recovery			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0072	150	$ 1.08	$ 0.0079	150	$ 1.19	$ 0.11	9.72%
Smart Meter Disposition Rider			1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0093	150	$ 1.40	$ -	150	$ -	-$ 1.40	-100.00%
Tax change	per kWh	-$ 0.0006	150	-$ 0.09		150	$ -	$ 0.09	-100.00%
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Sub-Total A				$ 14.45			$ 14.47	**$ 0.03**	**0.19%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0096	150	-$ 1.44	-$ 0.0040	150	-$ 0.60	$ 0.84	-58.61%
Global Adjustment - Non RPP		$ -	0	$ -	$ 0.0018	0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Low Voltage Service Charge				$ -		0	$ -	$ -	
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 13.01**			**$ 13.88**	**$ 0.87**	**6.70%**
RTSR - Network	per kWh	$ 0.0072	150	$ 1.08	$ 0.0077	150	$ 1.16	$ 0.08	7.29%
RTSR - Line and Transformation Connection	per kWh	$ 0.0048	150	$ 0.72	$ 0.0048	150	$ 0.72	$ 0.00	0.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 14.81**			**$ 15.76**	**$ 0.95**	**6.43%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	150	$ 0.78	$ 0.0044	155	$ 0.68	-$ 0.10	-12.43%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	150	$ 0.17	$ 0.0012	155	$ 0.19	$ 0.02	12.90%
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	150	$ 1.05	$ 0.0070	155	$ 1.09	$ 0.04	3.49%
Energy - RPP - Tier 1		$ 0.0750	0	$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
Energy - COP	per kWh	$ 0.0855	150	$ 12.82	$ 0.0855	155	$ 13.26	$ 0.45	3.49%
Total Bill on RPP (before Taxes)				**$ 17.05**			**$ 17.96**	**$ 0.91**	**5.35%**
HST		13%		$ 2.22	13%		$ 2.34	$ 0.12	5.35%
Total Bill (including HST)				$ 19.27			$ 20.30	$ 1.03	5.35%
Ontario Clean Energy Benefit [1]				-$ 1.93			-$ 2.03	-$ 0.10	5.18%
Total Bill on RPP (including OCEB)				**$ 17.34**			**$ 18.27**	**$ 0.93**	**5.37%**
Total Bill on TOU (before Taxes)				**$ 29.87**			**$ 31.23**	**$ 1.36**	**4.55%**
HST		13%		$ 3.88	13%		$ 4.06	$ 0.18	4.55%
Total Bill (including HST)				$ 33.75			$ 35.29	$ 1.54	4.55%
Ontario Clean Energy Benefit [1]				-$ 3.38			-$ 3.53	-$ 0.15	4.44%
Total Bill on TOU (including OCEB)				**$ 30.37**			**$ 31.76**	**$ 1.39**	**4.57%**

Loss Factor (%) Current: 4.20% Proposed: 3.49%

[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.

File Number:	EB-2012-0109
Exhibit:	Interrgatory Response
Tab:	
Schedule:	
Page:	
Date:	July 17 2013
Revised:	October 23 2013

Appendix 2-W
Bill Impacts

Customer Class: **Embedded Distributor**

Consumption 166168 kW ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
Consumption 78857860 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	$ 293.7100	1	$ 293.71	$ 298.9800	1	$ 298.98	$ 5.27	1.79%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Recovery			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.7488	166168	$ 290,594.60	$ 1.7802	166168	$ 295,812.27	$ 5,217.68	1.80%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	166168	$ -	$ -	166168	$ -	$ -	
Tax change	per kW	-$ 0.0307	166168	-$ 5,101.36	$ -	166168	$ -	$ 5,101.36	-100.00%
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Sub-Total A				$ 285,786.95			$ 296,111.25	**$ 10,324.30**	**3.61%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	166168	$ -		166168	$ -	$ -	
Global Adjustment - Non RPP	per kW	$ -	166168	$ -		166168	$ -	$ -	
				$ -		0	$ -	$ -	
				$ -		0	$ -	$ -	
Low Voltage Service Charge				$ -		0	$ -	$ -	
Smart Meter Entity Charge						0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 285,786.95**			**$ 296,111.25**	**$ 10,324.30**	**3.61%**
RTSR - Network	per kW	$ 2.4601	166168	$ 408,789.90	$ 2.6394	166168	$ 438,586.41	$ 29,796.51	7.29%
RTSR - Line and Transformation Connection	per kW	$ 1.6398	166168	$ 272,482.29	$ 1.6423	166168	$ 272,902.05	$ 419.77	0.15%
Sub-Total C - Delivery (including Sub-Total B)				**$ 967,059.13**			**$ 1,007,599.72**	**$ 40,540.59**	**4.19%**
Wholesale Market Service Charge (WMSC)	per kWh		78857860	$ -		78857860	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	per kWh		78857860	$ -		78857860	$ -	$ -	
Standard Supply Service Charge	Monthly		1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh		78857860	$ -		78857860	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0740	0	$ -	$ 0.0740	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
Energy - COP		$0.08545	78857860	$ 6,738,404.14	$0.08545	78857860	$ 6,738,404.14	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 967,059.13**			**$ 1,007,599.72**	**$ 40,540.59**	**4.19%**
HST		13%		$ 125,717.69	13%		$ 130,987.96	$ 5,270.28	4.19%
Total Bill (including HST)				$ 1,092,776.82			$ 1,138,587.68	$ 45,810.86	4.19%
Ontario Clean Energy Benefit [1]				-$ 109,277.68			-$ 113,858.77	-$ 4,581.09	4.19%
Total Bill on RPP (including OCEB)				**$ 983,499.14**			**$ 1,024,728.91**	**$ 41,229.77**	**4.19%**
Total Bill on TOU (before Taxes)				**$ 7,705,463.27**			**$ 7,746,003.86**	**$ 40,540.59**	**0.53%**
HST		13%		$ 1,001,710.23	13%		$ 1,006,980.50	$ 5,270.28	0.53%
Total Bill (including HST)				$ 8,707,173.50			$ 8,752,984.36	$ 45,810.86	0.53%
Ontario Clean Energy Benefit [1]				-$ 870,717.35			-$ 875,298.44	-$ 4,581.09	0.53%
Total Bill on TOU (including OCEB)				**$ 7,836,456.15**			**$ 7,877,685.92**	**$ 41,229.77**	**0.53%**

Loss Factor (%) 0.00% 0.00%

[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.

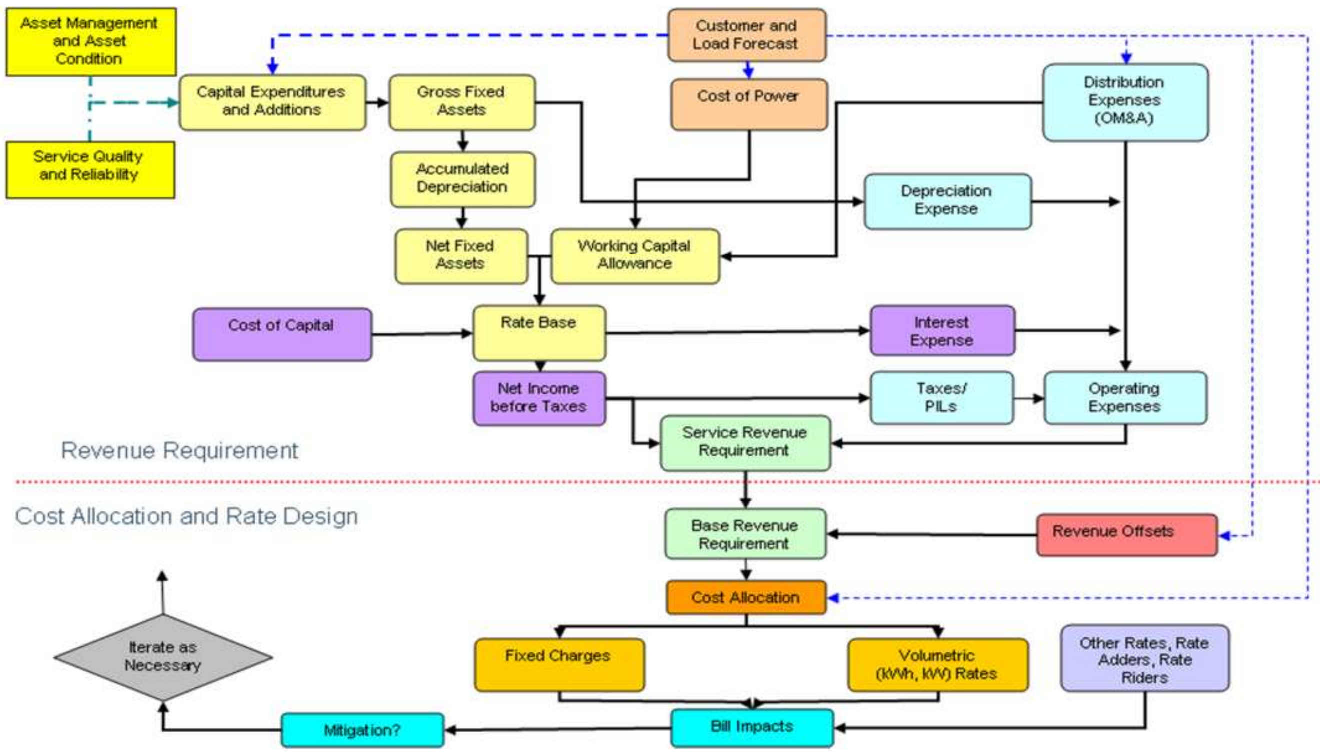
Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

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.

File Number:	EB-2012-0109
Exhibit:	
Tab:	
Schedule:	
Page:	59
Date:	17-Jul-13

Appendix 2-X
Cost of Service Rate Application Schematic

The Cost of Service Rate Application Schematic is a flowchart appended to Chapter 2 of the Filing Requirements as a guide for the components of an application and how demand and costs interrelate to derive the revenue requirement and then how the revenue requirement is allocated between classes and through fixed/variable splits to derive rates that will be compensatory for the annual revenue requirement, based on the the forecasted demand. There is no form to be filled out; therefore, this Schedule is not required to be filed.



ATTACHMENT S

REFERENCE: 1 Staff-1

Please refer to the Updated Revenue Requirement Work Form

Revenue Requirement Workform

Version 3.00

Utility Name	Brantford Power Inc.
Service Territory	*Brantford*
Assigned EB Number	2012-0109
Name and Title	Heather Wyatt, Director Regulatory Affairs, Board S
Phone Number	519-751-3522 ext. 3269
Email Address	hwyatt@brantford.ca

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

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	Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$99,621,478		($1,610,821)	$ 98,010,657			$98,010,657	
	Accumulated Depreciation (average)	($34,814,160)	(5)	$637,817	-$34,176,343			-$34,176,343	
	Allowance for Working Capital:								
	Controllable Expenses	$9,216,025		$ -	$ 9,216,025			$9,216,025	
	Cost of Power	$98,022,828		($2,956,203)	$ 95,066,625			$95,066,625	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)		13.00%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$15,293,896		-$197,688	$15,096,208				
	Distribution Revenue at Proposed Rates	$16,703,454		-$70,140	$16,633,314				
	Other Revenue:								
	Specific Service Charges	$422,134		$0	$422,134				
	Late Payment Charges	$120,000		$0	$120,000				
	Other Distribution Revenue	$639,012		-$0	$639,012				
	Other Income and Deductions	($20,000)		$0	($20,000)				
	Total Revenue Offsets	$1,161,146	(7)	-$0	$1,161,146				
	Operating Expenses:								
	OM+A Expenses	$9,204,025		$ -	$ 9,204,025			$9,204,025	
	Depreciation/Amortization	$2,995,584	(10)	$ -	$ 2,995,584			$2,995,584	
	Property taxes	$12,000		$ -	$ 12,000			$12,000	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($1,325,186)	(3)		($1,227,322)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$362,603			$376,430				
	Income taxes (grossed up)	$477,851			$496,909				
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	9.12%			9.25%				
	Income Tax Credits	$ -			$ -				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)	0.0%			0.0%				
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	5.17%			5.17%				
	Short-term debt Cost Rate (%)	2.07%			2.07%				
	Common Equity Cost Rate (%)	8.98%			8.98%				
	Prefered Shares Cost Rate (%)	0.00%			0.00%				
	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.

Adjustments are a result of updating the Fixed Asset Continuity Schedule to reflect 2012 actual figures.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application		Adjustments		Interrogatory Responses		Adjustments		Per Board Decision
1	Gross Fixed Assets (average)	(3)	$99,621,478		($1,610,821)		$98,010,657		$ -		$98,010,657
2	Accumulated Depreciation (average)	(3)	($34,814,160)		$637,817		($34,176,343)		$ -		($34,176,343)
3	Net Fixed Assets (average)	(3)	$64,807,318		($973,004)		$63,834,314		$ -		$63,834,314
4	Allowance for Working Capital	(1)	$13,941,051		($384,306)		$13,556,745		$ -		$13,556,745
5	**Total Rate Base**		$78,748,369		($1,357,310)		$77,391,059		$ -		$77,391,059

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application		Adjustments		Interrogatory Responses		Adjustments		Per Board Decision
6	Controllable Expenses		$9,216,025		$ -		$9,216,025		$ -		$9,216,025
7	Cost of Power		$98,022,828		($2,956,203)		$95,066,625		$ -		$95,066,625
8	Working Capital Base		$107,238,853		($2,956,203)		$104,282,650		$ -		$104,282,650
9	Working Capital Rate %	(2)	13.00%		0.00%		13.00%		0.00%		13.00%
10	Working Capital Allowance		$13,941,051		($384,306)		$13,556,745		$ -		$13,556,745

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.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$16,703,454	($70,140)	$16,633,314	$ -	$16,633,314
2	Other Revenue	(1)	$1,161,146	($0)	$1,161,146	$ -	$1,161,146
3	Total Operating Revenues		$17,864,600	($70,140)	$17,794,460	$ -	$17,794,460
	Operating Expenses:						
4	OM+A Expenses		$9,204,025	$ -	$9,204,025	$ -	$9,204,025
5	Depreciation/Amortization		$2,995,584	$ -	$2,995,584	$ -	$2,995,584
6	Property taxes		$12,000	$ -	$12,000	$ -	$12,000
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$12,211,609	$ -	$12,211,609	$ -	$12,211,609
10	Deemed Interest Expense		$2,346,500	($40,444)	$2,306,055	$ -	$2,306,055
11	Total Expenses (lines 9 to 10)		$14,558,108	($40,444)	$14,517,664	$ -	$14,517,664
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**		$3,306,492	($29,696)	$3,276,796	$ -	$3,276,796
14	Income taxes (grossed-up)		$477,851	$19,058	$496,909	$ -	$496,909
15	**Utility net income**		$2,828,641	($48,754)	$2,779,886	$ -	$2,779,886

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$422,134	$ -	$422,134		$422,134
	Late Payment Charges	$120,000	$ -	$120,000		$120,000
	Other Distribution Revenue	$639,012	($0)	$639,012		$639,012
	Other Income and Deductions	($20,000)	$ -	($20,000)		($20,000)
	Total Revenue Offsets	$1,161,146	($0)	$1,161,146	$ -	$1,161,146

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,828,641	$2,779,887	$2,779,887
2	Adjustments required to arrive at taxable utility income	($1,325,186)	($1,227,322)	($1,325,186)
3	Taxable income	$1,503,455	$1,552,565	$1,454,701
	Calculation of Utility income Taxes			
4	Income taxes	$362,603	$376,430	$376,430
6	Total taxes	$362,603	$376,430	$376,430
7	Gross-up of Income Taxes	$115,248	$120,479	$120,479
8	Grossed-up Income Taxes	$477,851	$496,909	$496,909
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$477,851	$496,909	$496,909
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	9.12%	9.25%	9.25%
13	Total tax rate (%)	24.12%	24.25%	24.25%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$44,099,087	5.17%	$2,281,296
2	Short-term Debt	4.00%	$3,149,935	2.07%	$65,204
3	**Total Debt**	60.00%	$47,249,021	4.97%	$2,346,500
	Equity				
4	Common Equity	40.00%	$31,499,348	8.98%	$2,828,641
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$31,499,348	8.98%	$2,828,641
7	**Total**	100.00%	$78,748,369	6.57%	$5,175,141
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$43,338,993	5.17%	$2,241,975
2	Short-term Debt	4.00%	$3,095,642	2.07%	$64,080
3	**Total Debt**	60.00%	$46,434,635	4.97%	$2,306,055
	Equity				
4	Common Equity	40.00%	$30,956,424	8.98%	$2,779,887
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$30,956,424	8.98%	$2,779,887
7	**Total**	100.00%	$77,391,059	6.57%	$5,085,942
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$43,338,993	5.17%	$2,241,975
9	Short-term Debt	4.00%	$3,095,642	2.07%	$64,080
10	**Total Debt**	60.00%	$46,434,635	4.97%	$2,306,055
	Equity				
11	Common Equity	40.00%	$30,956,424	8.98%	$2,779,887
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$30,956,424	8.98%	$2,779,887
14	**Total**	100.00%	$77,391,059	6.57%	$5,085,942

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

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

		Initial Application		Interrogatory Responses		Per Board Decision	
Line No.	**Particulars**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**
1	Revenue Deficiency from Below		$1,409,559		$1,537,107		$1,537,107
2	Distribution Revenue	$15,293,896	$15,293,895	$15,096,208	$15,096,207	$15,096,208	$15,096,207
3	Other Operating Revenue Offsets - net	$1,161,146	$1,161,146	$1,161,146	$1,161,146	$1,161,146	$1,161,146
4	**Total Revenue**	$16,455,042	$17,864,600	$16,257,354	$17,794,460	$16,257,354	$17,794,460
5	Operating Expenses	$12,211,609	$12,211,609	$12,211,609	$12,211,609	$12,211,609	$12,211,609
6	Deemed Interest Expense	$2,346,500	$2,346,500	$2,306,055	$2,306,055	$2,306,055	$2,306,055
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**	$14,558,108	$14,558,108	$14,517,664	$14,517,664	$14,517,664	$14,517,664
9	**Utility Income Before Income Taxes**	$1,896,934	$3,306,492	$1,739,690	$3,276,796	$1,739,690	$3,276,796
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,325,186)	($1,325,186)	($1,227,322)	($1,227,322)	($1,227,322)	($1,227,322)
11	**Taxable Income**	$571,747	$1,981,306	$512,368	$2,049,474	$512,368	$2,049,474
12	Income Tax Rate	24.12%	24.12%	24.25%	24.25%	24.25%	24.25%
13	**Income Tax on Taxable Income**	$137,894	$477,851	$124,227	$496,909	$124,227	$496,909
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$1,759,040	$2,828,641	$1,615,462	$2,779,886	$1,615,462	$2,779,886
16	**Utility Rate Base**	$78,748,369	$78,748,369	$77,391,059	$77,391,059	$77,391,059	$77,391,059
17	Deemed Equity Portion of Rate Base	$31,499,348	$31,499,348	$30,956,424	$30,956,424	$30,956,424	$30,956,424
18	Income/(Equity Portion of Rate Base)	5.58%	8.98%	5.22%	8.98%	5.22%	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	-3.40%	0.00%	-3.76%	0.00%	-3.76%	0.00%
21	Indicated Rate of Return	5.21%	6.57%	5.07%	6.57%	5.07%	6.57%
22	Requested Rate of Return on Rate Base	6.57%	6.57%	6.57%	6.57%	6.57%	6.57%
23	Deficiency/Sufficiency in Rate of Return	-1.36%	0.00%	-1.50%	0.00%	-1.50%	0.00%
24	Target Return on Equity	$2,828,641	$2,828,641	$2,779,887	$2,779,887	$2,779,887	$2,779,887
25	Revenue Deficiency/(Sufficiency)	$1,069,602	($0)	$1,164,424	($0)	$1,164,424	($0)
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,409,559 **(1)**		$1,537,107 **(1)**		$1,537,107 **(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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$9,204,025		$9,204,025		$9,204,025	
2	Amortization/Depreciation	$2,995,584		$2,995,584		$2,995,584	
3	Property Taxes	$12,000		$12,000		$12,000	
5	Income Taxes (Grossed up)	$477,851		$496,909		$496,909	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$2,346,500		$2,306,055		$2,306,055	
	Return on Deemed Equity	$2,828,641		$2,779,887		$2,779,887	
	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)**	$17,864,601		$17,794,460		$17,794,460	
9	Revenue Offsets	$1,161,146		$1,161,146		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$16,703,454		$16,633,314		$17,794,460	
11	Distribution revenue	$16,703,454		$16,633,314		$16,633,314	
12	Other revenue	$1,161,146		$1,161,146		$1,161,146	
13	**Total revenue**	$17,864,600		$17,794,460		$17,794,460	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	**(1)**	($0)	**(1)**	($0)	**(1)**

Notes

(1) Line 11 - Line 8

ATTACHMENT T

REFERENCE: 1.0 Staff-2

Please refer to the Updated Cost Allocation Study.

Cost Allocation Model ("CA Model") Version 3.0

Instructions Sheet

General:
These instructions are included with the OEB CA Model version 3 as a reference for distributor staff and other users of the model.
Version 3.0 is designed for use with 2013 rate applications. It is identical to Version 2 except for accommodating the deferred PP&E balance due to the transition to IFRS
The instructions are organized by input sheet (I1 to I9), followed by suggestions of how to use output sheets O1, O3.1 and O3.6. The remaining output sheets and exhibit sheets (E1 to E5) and the procedure for closing the files are unchanged from version 1.2 of the cost allocation model except for incidental adjustments that do not require any attention from the model user.
There are numerous references in these instructions to specific Excel cells in the Revenue Requirement Work Form ("RRWF"), which will be filed in support a cost-of-service distribution rate application at the same time as the CA Model. The cross-references to RRWF are intended to ensure consistency within the application. If the applicant plans on completing the Cost Allocation before the RRWF is complete, the best practice is to input the required information from the primary sources that will be used later in the RRWF. As an alternative, a less-than-best option is to leave the required inputs blank temporarily, and overlook the

- A staff report "Board Staff Implementation of the Board's Findings on the Review of Electricity Cost Allocation Policy" documents the rationale for changes in Version 2 relative

The original model and related documents are on the web-site in EB-2005-0317; http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Archived+OEB+Key+Initiatives/Cost+Allocation+Review.

Worksheet I1 Introduction
This input worksheet is for basic information about the utility.
- Inputs to Cells B2, C9, C13 and C15 are carried forward to the heading on all worksheets, and do not require updating after the initial set-up.
- Include test year in Cell B2 e.g. '2012 COS Cost Allocation'.
- The date in Cell C15 should be updated every time a new run of the model is filed (Interrogatories, draft rate order, etc.).

Worksheet I2 LDC Classes

The rate classes are defined in this input worksheet.

- Input to Cell C-17 is copied to the header of all worksheets. When the CA Model is modified for a specific reason, such as a run using final proposed rates for the purposes of a draft rate order, a new description should be entered in Cell C-17.
- Cell C20 and below shows common rate class names. Substitute the proper name if applicable. Any input to Column D will appear as the column headings if different from
- In Column E, choose Yes or No as applicable for the proposed customer classes, and
- Do not include microFIT as a rate classification in CA Model until further notice in the
- If the distributor is a Host Distributor, select Yes for Embedded Distributor class. (For possible exception, see 'Filing Requirements' section 2.10.1).
- Be aware that the "Update" button hides and unhides columns, nothing more. If you have entered data for a class in an input sheet, the data will remain unlessl you delete it. (If you enter data for a class, subsequently change to 'No' for that class in I-2, and click Update but neglect to delete data, the hidden data will continue to affect range totals and
- For the user's convenience, a space is available at B46 to describe a scenario (customer classes, load data, choice of allocators, etc.) to keep track of alternative cost allocation outcomes as they are being studied. Cell C 17 should describe the scenario.

Worksheet I3 Trial Balance Data

- The account balances are entered and adjusted in this input worksheet.

  - At Cell F10, input the return on equity RRWF tab 9 'Revenue Requirement' cell F23;
  - At Cell F11, input the forecast of PILs from RRWF tab 9 'Revenue Requirement' cell
  - At Cell F12, input Interest Cost from RRWF tab 9 'Revenue Requirement' cell F22;
  - **At Cell F13, input Return on Rate Base Associated with Deferred PP&E balance;**
  - Cell F14 should b entered equal to RRWF tab 9 'Service Revenue Requirement' cell
  - Cell F16 should be entere equal to RRWF tab 4 'Rate Base' cell G19
- Starting at Row 21, enter forecast amounts for USoA accounts. The CA Model has a few new Rows that have been added in worksheet I-3 and in the subsequent worksheets. These Rows are inserted to enable new accounts or finer granularity within existing
- Column D contains the forecast amounts for the test year, and is to match the amounts in the rate application. For asset accounts, enter the mid-year average amounts matching

- **Cell D430 is Amortization on PP&E including the adjustment resulting from the amortization of Account 1575**
- Column F is available to re-assign amounts among the accounts in Column D. Generally if costs are removed from one USoA account and added to another account, the rationale for the re-assignment is to be provided by the distributor in its prefiled evidence.
- Column F is especially useful for removing part of the cost from a parent account and adding the same amount into a sub-account that is allocated by a different allocator than the parent account. If the sub-account has been set up in version 2 of the model e.g.
- Row 252 has been added, to allow for separate allocation of revenue from the SSS Administration Charge. Enter the amount of the sub-account at Cell F252 and enter negative the same amount (i.e. positive) in Cell F250. No explanation is required.

- Rows 265 and 266 have been added, to allow for separate allocation of the Account Set-Up Charges sub-account distinct from other revenue streams in Account 4235. Enter the sub-account amount at Cell F265 and F266 and enter negative the same amounts at
- Column I has drop-down menus in the new Rows. If necessary use the menu to select the allocator for the account that the distributor considers most appropriate. (The model on the website has an allocator already selected at the suggestion of the CA Working Group, but the distributor is ultimately responsible for selecting the most appropriate

- Column I provides a drop-down menu to select an allocator for any new IFRS-related
- Column G is used for costs that are directly allocated. Put the appropriate total amount in Column G, and repeat for the appropriate class in worksheet I9.
- Note that the model has Rows in I9 for most capital and OM&A accounts, but not revenue accounts. If an account has no corresponding Row in I9, the model does not

Worksheet I4 Break Out Assets

This input worksheet is for breaking the asset accounts into a more granular level.

- Cell C12 requires data entry from the RRWF tab 4. Rate Base, Cell G14 to ensure consistency between the cost allocation model and the rest of the application.
- **Note: In Cell L57, enter the annual depreciation expense adjustment resulting from amortization of account 1575**

Worksheet I5.1 Miscellaneous Data

There are two new input cells in version 2 of the input worksheet:

- In Cell D19, enter the percentage of OM&A plus Cost of Power that is included as working capital, i.e. 15%, or a percentage based on the distributor's lead-lag study; and
- Cell D21 yields a weighting factor to attribute pole access revenue in proportion to the corresponding costs. Considering all poles that yield pole rental revenue, enter the estimated percentage of NBV in poles that are at Secondary voltage, as distinct from the

Worksheet I5.2 Weighting Factors

This worksheet is used to input each class' weighting factor for services and Billing and Collection. Use a single factor suitable for the whole class. See examples in the boxes below.

- Row 11: calculate weighting factors reflecting only installed capital costs recorded in
- Row 15: calculate weighting factors reflecting costs in Account 5315 – Customer Billing, Account 5320 – Collecting, and Account 5340 – Miscellaneous Customer Account
- Default weights are no longer provided in the model. The weights previously provided in version 1.2 can be found in the Board staff's implementation documentation [EB-2010-

Example: **Weighting Factor for Services:**

Assume that the amount recorded in 1855 for a typical residential customer is $1,000.
Assume that there are 500 customers in the GS>50 class.
Assume that 100 of them are industrial customers served by a single span of overhead conductor. The amount remaining on the books in Account 1855 is small, but the current cost

Assume that 100 customers have underground service that required extensive permits, street repairs, and labour costs, as well as materials. The services are recent, and the amount
Assume 300 customers have no costs recorded in Account 1855, and would have no cost recorded even if replaced (per distributor's accounting practice and conditions of service)
Calculation:

➢ [(100 * $5,000) + (100 * $25,000) + (300 * $0)] / 500 = $6,000 per customer

Weighting factor for residential = $1,000/$1,000 = 1.00
Weighting factor for GS>50 kW = $6,000/$1,000 = 6.00

Example: **Weighting Factor for Billing and Collecting:**

Assume that the Residential cost averaged over all residential customers is $1.50 for bill preparation and mailing, $0.50 to record revenue from a normal payment, and $1.00 per bill on average for other costs associated with collecting, etc. that are recorded in accounts 5315,
Assume that there are 15 customers in the USL class:
Assume that 5 of the customers have a large number of devices and the number of devices changes from time to time, so additional clerical attention is required each month amounting to $50 over the group ($10 per bill). Including $1.00 postage and incidental costs, the cost of billing is $11 per bill. Including the costs of recording revenue at the same as for residential
Assume the other 10 USL customers have a small number of devices and require the same amount of effort as a typical residential customer. There are less issues with collecting, so the incidental costs are $0.50 per month. Total cost is $2.50 per bill
Calculation:

➢ [(5 * $11.50) + (10 * $2.50)] / 15 = $5.50 per bill.

Weighting factor for Residential = $3.00 / $3.00 = 1.00
Weighting factor for USL = $5.50 / $3.00 = 1.83

Worksheet I6.1 Revenue

This input sheet has been modified in version 2 to calculate the test year revenues based on the test year volumetric forecast and the current rates.

- Cells B10, B13, B16 and B19 are inputs from application exhibits: the first two from Exhibit 3 Load Forecast, and the latter two from the RRWF.
- CA Model version 2 has been adapted to calculate class revenues at existing rates and forecast billing quantities. (The previous versions required class revenues as inputs to
- Cell B10 – from Exhibit 3 of the application, input total energy from the test year load forecast, adjusted downward for distribution line losses.
- Cell B13 – from Exhibit 3 of the application, input the total billing demands of all demand
- Cell B16 –from RRWF tab 8 Revenue Deficiency/Sufficiency H16.
- Cell B19 – enter data from RRWF tab 8. Revenue Deficiency/Sufficiency F18.
- Rows 25 and 26: enter weather-normalized load after line losses. These quantities will be the results found in the distributor's load forecast Exhibit 3.
- Rows 31, 44, 50 and 51 no longer play a role in the model, as long as Rows 25 and 26 are based on normalized weather load forecasts. Version 2 now relies on the distributor's load forecast rather than the analysis provided originally by Hydro One.
- Rows 33-36 - enter the currently approved rates for each class;

- Row 37 – a placeholder Row for any other rate (e.g. separate rates per street lighting
- Row 39– the revenue formula is based on fixed monthly revenue from billing the largest of customer / connection / devices from Rows 18, 19 and 21 in worksheet I6.2. If this is not appropriate for the distributor's rate structure, the distributor should correct the formula for the applicable class(es) in Row 39. (For example, if USL is billed per customer, per device and per kW, the formula will require inputs from Rows 27, 33, 35, 37, and
- As an alternative run of the CA Model, but not for submission with the application, to check the internal consistency of the application it may be informative to enter the rates that are being proposed in the application in Rows 33-36. See notes to Worksheet O-1
- If the Conditions of Service for a class of large customers require that all customers supply their own transformation, Row 26 and/or Row 36 should be entered as zero for that

Worksheet I6.2 Customer Data

This input sheet is for inputting the various customer data by rate class, such as number of

- Row 18 'Number of devices' has been added in version 2 of the model. Generally this will require input for the Street Lighting and Unmetered Scattered Load classes;
- The number of devices (Row 18) should be equal to or greater than the number of
- The number of connections should be equal to or greater than the number of customers

Worksheet I7.1 Meter Capital

The purpose of this input worksheet is to derive the weighting factor of each class for the allocator CWMC, which is used to allocate accounts 1860 Meters, 5065 Meter Expense, and 5175 Maintenance. It does not affect the deferral account 1555 Smart Meter Capital and

- As a general rule, include one meter per customer in this worksheet, i.e. include smart meter or standard meter, not both.
- Replace meter descriptions in Column C with new descriptions that match the meters actually in use, and input the applicable average installed replacement cost of each type of
- During the transitional period, until all smart meters are in the Rate Base, include in the documentation of the application an explanation of which unit cost is being used. Since the weighting factor will remain unchanged during the IRM period, the distributor may consider including smart meters rather than the soon-to-be-stranded meters, even though
- If the cost of equipment used to download billing data is included in Account 1860 – Meters, the cost of such equipment should be considered in this worksheet. Version 2 of the model does not make provision for doing this. The user may add a Row or Rows for the cost (cost per customer and number of customers) of such equipment. The additional
- Note that Account 1920 – Computer Hardware, Account 1925 – Computer Software and Account 1955 – Communications Equipment are allocated to the customer classes by the composite allocator Net Fixed Assets (excluding credit for capital contributions). If equipment for automated meter-reading and data storage are recorded in these accounts, the distributor may consider moving capital costs to Account 1860 – Meters in worksheet I-3 and reflecting this in the meter capital weighting factors, with the objective of reaching a
- Entries for USL, Street lighting and Sentinel Lighting in worksheet I7.1 and I7.2 are 0. For any cost of estimating or verifying unmetered loads, see note re direct allocation

Worksheet I7.2 Meter Reading

The purpose of this input worksheet is to derive the weighting factors for the allocator CWMR, which is used only to allocate costs that are recorded in account 5310 Meter Reading Expense. The data in Column C are relative amounts, with the typical Residential reading
Version 2 of this worksheet has not been modified to reflect automated meter reading. The Rows in worksheet I7.2 reflect differences in customer density, relative difficulty in reaching the meter, and frequency of reading the meter in the respective classes. To the extent that these factors are now more nearly uniform due to automated meter reading, the distributor

Worksheet I8 Demand Data
This input sheet is to record the various coincident and non-coincident peaks by rate class, which are used a cost allocators in the CA Model.

- No changes in version 2 of this worksheet.

Worksheet I9 Direct Allocation
This input worksheet allows for directly allocating costs to specific rate classes.

- Remember that costs associated with revising estimated consumption of unmetered loads may be allocated directly to the applicable class. [EB-2005-0317, Cost allocation
- Additional information on direct allocations can be found above in the notes for Column G in input sheet I3 Trial Balance.

Worksheet O1
This is an output worksheet that shows the allocated revenue requirements and the revenue-to-cost ratios by rate class. Use this sheet to check that the allocated costs reconcile to the

- In these instructions for Worksheet 01, "RRWF" means RRWF tab 8. Revenue
- "Appendix 2-Q" means Appendix 2-Q in 2013 Filing Requirements.
- Row 18 – Distribution Revenue at Existing Rates:
  - Cell C18 should equal the total in RRWF Cell F17 – Distribution Revenue at Currently
  - Cells D18 and beyond are the inputs to Appendix 2-Q, Table B, Column 7B.
- Row 19 – Miscellaneous Revenue:
  - Cell C19 should equal RRWF Cell F18,
  - Cells D19 and beyond are the inputs to Appendix 2-Q, Table B, Column 7E,
  - Note the diagnostic test in Row 20 for Miscellaneous Revenue. The model calculates the status quo rates from the test year Service Revenue Requirement less Miscellaneous Revenue. If Miscellaneous Revenue is entered inaccurately, the status quo rates and status quo ratios in Row 75 will also be inaccurate for the respective
- Cell C21 – Total Revenue at Existing Rates should be equal to RRWF Cell F19;
- Row 23 – Distribution Revenue at Status Quo Rates":
  - Cell C23 should equal RRWF, sum of Cells H16 & H17
  - Cells D23 and beyond are the hypothetical distribution revenue, by class, if there were no rate re-balancing. These cells are the inputs to Appendix 2-Q, Table B,
- Cell C25 should equal RRWF Cell H19 – Total Revenue.
- Row 40 – Revenue Requirement (includes NI):
  - Cell C40 is the total revenue requirement, and should be equal to RRWF worksheet tab 9 Revenue Requirement, Cell F22; and
  - Cells D40 and beyond are inputs to Appendix O, table (a), Column 7A.

- Row 75 – Revenue to Expenses Status Quo:
  - Cell C75 should equal 100%, and
  - Cells D75 and beyond are the inputs to Appendix 2-Q, table C, second column
- Cells C71 and C81 should equal the corresponding target returns on equity (RRWF

The 2012 Filing Requirements do not require a version of the model with proposed rates. However, it may be helpful to the user to verify the proposed distribution rates and ratios by substituting proposed rates in place of currently approved ones.

It may also be useful to run an updated version when preparing a Draft Rate Order:

- At worksheet I3, modify Miscellaneous Income accounts if necessary, along with forecast capital and OM&A accounts, if any of these have changed as a result of a
- At worksheet I6.1, modify the class load forecast inputs if it has changed since the original application, at Rows 25 and 26.
- At worksheet I6.1, substitute the proposed rates at Rows 33 – 36.
- At worksheet I8, data may need to be changed if the load forecast has been changed.
- On worksheet O1:
  - Cell C22 should now equal 1.00 and Rows 18 and 23 should be identical.
  - Cells D75 and beyond should show the proposed revenue to cost ratios.

Worksheet O3.1

The purpose of this output worksheet is to provide information on the cost per unit of providing customers with transformation service.

- Row 27, expresses the transformer costs in per kW terms. The amount found in Row 27 is not necessarily identical to the cost that would be saved if the customer provides its own transformer. While it is useful information, the value in Row 27 should not be presented as the sole evidence to support changing the Transformer Ownership

Worksheet O3.6

The purpose of this output worksheet is to provide information to be used to update the provincial standard monthly charge for microFIT installations.

- Check that Cell 23 is equal to O-2 Cell D132 less Cell D81, which is an update of the information that underpins the current rate; and
- Cells C24 and C25 have been added in version 2 of the model per Board Report (p. 8).

If the distributor intends to propose a microFIT charge based on its own costs, this will require sub-account information as per the Board's FAQ # 18, December 23, 2010. The information from Worksheet O-3.6 will not likely be considered relevant for approval of a non-uniform

Worksheets E2 and E4

allocators. The allocators are linked to the USoA accounts in worksheet E4.
In version 3 a new allocator “PP&E” has been added for the amortization of the deferred PP&E balance. The model defaults to the same proportions as Net Fixed Assets “NFA”. If the distributor is applying to allocate the PP&E balance in some other proportions, those proportions may be input directly in E2 by substituting the formula or entering percentages along last row of the worksheet.

Model

E3	PLCC	Backup documentation for calculating Peak Load Carrying Capability.
E4	Trial Balance Index	Exhibit showing 1. how accounts are grouped for reporting, how accounts are categorized and how accounts are allocated
E5	Reconciliation	Exhibit showing reconciliation of accounts included and excluded from the allocation study to TB balance

2013 Cost Allocation

Sheet I2 Class Selection - 1-Staff-2 Updated Cost Allocation

Instructions:
Step 1: Please input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

Please Provide a summary of this Run
1-Staff-2 Updated Cost Allocation Study

		Utility's Class Definition	Current
1	Residential		YES
2	GS <50		YES
3	GS>50-Regular		YES
4	GS> 50-TOU		NO
5	GS >50-Intermediate		NO
6	Large Use >5MW		NO
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		YES
11	Back-up/Standby Power		NO
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

** **Space available for additional information about this run**

2013 Cost Allocation Model

Sheet I3 Trial Balance Data - 1-Staff-2 Updated Cost Allocation Study

Return on Deemed Equity	$2,779,887	
Income Taxes (Grossed up)	$496,909	
Deemed Interest Expense	$2,306,055	
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		
Service Revenue Requirement	$17,794,460	**From this Sheet**
Revenue Requirement to be Used in this model ($)	$17,794,460	**$17,794,460**
Rate Base ($)	$77,391,058	
Rate Base to be Used in this model ($)	$77,391,058	**$77,391,058**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation
1005	Cash		$ 10,614,700.00			
1010	Cash Advances and Working Funds		$ 700.00			
1020	Interest Special Deposits		$ -			
1030	Dividend Special Deposits		$ -			
1040	Other Special Deposits		$ 1,125,000.00			
1060	Term Deposits		$ -			
1070	Current Investments		$ -			
1100	Customer Accounts Receivable		$ 9,639,000.00			
1102	Accounts Receivable - Services		$ -			
1104	Accounts Receivable - Recoverable Work		$ -			
1105	Accounts Receivable - Merchandise, Jobbing, etc.		$ -			
1110	Other Accounts Receivable		$ -			
1120	Accrued Utility Revenues		$ 8,765,755.00			
1130	Accumulated Provision for Uncollectible Accounts--Credit		-$ 816,000.00			
1140	Interest and Dividends Receivable		$ -			
1150	Rents Receivable		$ -			
1170	Notes Receivable		$ -			
1180	Prepayments		$ 153,529.00			
1190	Miscellaneous Current and Accrued Assets		$ -			

1200	Accounts Receivable from Associated Companies		$ -			
1210	Notes Receivable from Associated Companies		$ -			
1305	Fuel Stock		$ -			
1330	Plant Materials and Operating Supplies		$ 1,502,142.00			
1340	Merchandise		$ -			
1350	Other Materials and Supplies		$ -			
1405	Long Term Investments in Non-Associated Companies		$ -			
1408	Long Term Receivable - Street Lighting Transfer		$ -			
1410	Other Special or Collateral Funds		$ 500,000.00			
1415	Sinking Funds		$ -			
1425	Unamortized Debt Expense		$ -			
1445	Unamortized Discount on Long-Term Debt--Debit		$ -			
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses		$ -			
1460	Other Non-Current Assets		$ -			
1465	O.M.E.R.S. Past Service Costs		$ -			
1470	Past Service Costs - Employee Future Benefits		$ -			
1475	Past Service Costs - Other Pension Plans		$ -			
1480	Portfolio Investments - Associated Companies		$ -			
1485	Investment in Associated Companies - Significant Influence		$ -			
1490	Investment in Subsidiary Companies		$ -			
1505	Unrecovered Plant and Regulatory Study Costs		$ -			
1508	Other Regulatory Assets		$ 1,090,695.00			
1510	Preliminary Survey and Investigation Charges		$ -			
1515	Emission Allowance Inventory		$ -			
1516	Emission Allowances Withheld		$ -			
1518	RCVARetail		$ 26,069.00			
1520	Power Purchase Variance Account					
1525	Miscellaneous Deferred Debits		$ 82.00			
1530	Deferred Losses from Disposition of Utility Plant		$ -			
1540	Unamortized Loss on Reacquired Debt		$ -			
1545	Development Charge Deposits/ Receivables		$ -			
1548	RCVASTR		$ 336,284.00			
1560	Deferred Development Costs		$ 965,741.00			
1562	Deferred Payments in Lieu of Taxes		$ -			
1563	Account 1563 - Deferred PILs Contra Account		-$ 48,847.00			
1565	Conservation and Demand Management Expenditures and Recoveries					
1570	Qualifying Transition Costs		$ -			
1571	Pre-market Opening Energy Variance		$ -			
1572	Extraordinary Event Costs		$ -			
1574	Deferred Rate Impact Amounts		$ -			
1580	RSVAWMS		-$ 1,648,435.00			
1582	RSVAONE-TIME		$ 355,849.00			
1584	RSVANW		$ 860,012.00			
1586	RSVACN		$ 474,764.00			
1588	RSVAPOWER		-$ 2,281,778.00			
1590	Recovery of Regulatory Asset Balances		$ -			
1605	Electric Plant in Service - Control Account					
1606	Organization					
1608	Franchises and Consents					
1610	Miscellaneous Intangible Plant					
1615	Land					
1616	Land Rights					
1620	Buildings and Fixtures					
1630	Leasehold Improvements		$ -			
1635	Boiler Plant Equipment		$ -			
1640	Engines and Engine-Driven Generators		$ -			
1645	Turbogenerator Units		$ -			
1650	Reservoirs, Dams and Waterways		$ -			
1655	Water Wheels, Turbines and Generators		$ -			
1660	Roads, Railroads and Bridges		$ -			
1665	Fuel Holders, Producers and Accessories		$ -			
1670	Prime Movers		$ -			
1675	Generators		$ -			
1680	Accessory Electric Equipment		$ -			
1685	Miscellaneous Power Plant Equipment		$ -			
1705	Land		$ -			
1706	Land Rights		$ -			
1708	Buildings and Fixtures		$ -			
1710	Leasehold Improvements		$ -			

1715	Station Equipment	$ -			
1720	Towers and Fixtures	$ -			
1725	Poles and Fixtures	$ -			
1730	Overhead Conductors and Devices	$ -			
1735	Underground Conduit	$ -			
1740	Underground Conductors and Devices	$ -			
1745	Roads and Trails	$ -			
1805	Land	$ 181,960.63			
1806	Land Rights	$ 94,990.60			
1808	Buildings and Fixtures	$ 1,163,731.71			
1810	Leasehold Improvements	$ -			
1815	Transformer Station Equipment - Normally Primary above 50 kV	$ 4,507,911.57			
1820	Distribution Station Equipment - Normally Primary below 50 kV	$ 74,426.57			
1825	Storage Battery Equipment	$ -			
1830	Poles, Towers and Fixtures	$ 17,073,915.83			
1835	Overhead Conductors and Devices	$ 13,029,744.04			
1840	Underground Conduit	$ 13,876,033.43			
1845	Underground Conductors and Devices	$ 19,021,891.56			
1850	Line Transformers	$ 17,634,771.92			
1855	Services	$ 1,618,784.77			
1860	Meters	$ 9,353,846.48			
9999	IFRS Placeholder Asset Account	$ -			
1865	Other Installations on Customer's Premises	$ -			
1870	Leased Property on Customer Premises	$ -			
1875	Street Lighting and Signal Systems	$ -			
1905	Land	$ -			
1906	Land Rights	$ -			
1908	Buildings and Fixtures	$ -			
1910	Leasehold Improvements	$ -			
1915	Office Furniture and Equipment	$ 3,113.00			
1920	Computer Equipment - Hardware	$ 184,128.73			
1925	Computer Software	$ 792,431.32			
1930	Transportation Equipment	$ 3,028,989.74			
1935	Stores Equipment	$ -			
1940	Tools, Shop and Garage Equipment	$ 156,492.15			
1945	Measurement and Testing Equipment	$ -			
1950	Power Operated Equipment	$ -			
1955	Communication Equipment	$ -			
1960	Miscellaneous Equipment	$ -			
1965	Water Heater Rental Units	$ -			
1970	Load Management Controls - Customer Premises	$ -			
1975	Load Management Controls - Utility Premises	$ -			
1980	System Supervisory Equipment	$ 772,336.92			
1985	Sentinel Lighting Rental Units	$ -			
1990	Other Tangible Property	$ -			
1995	Contributions and Grants - Credit	-$ 4,558,843.87			
2005	Property Under Capital Leases	$ -			
2010	Electric Plant Purchased or Sold	$ -			
2020	Experimental Electric Plant Unclassified	$ -			
2030	Electric Plant and Equipment Leased to Others	$ -			
2040	Electric Plant Held for Future Use	$ -			
2050	Completed Construction Not Classified--Electric	$ -			
2055	Construction Work in Progress--Electric	$ 24,009.00			
2060	Electric Plant Acquisition Adjustment	$ -			
2065	Other Electric Plant Adjustment	$ -			
2070	Other Utility Plant	$ -			
2075	Non-Utility Property Owned or Under Capital Leases	$ -			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-$ 34,176,343.19			
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$ -			
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	$ -			
2160	Accumulated Amortization of Other Utility Plant	$ -			
2180	Accumulated Amortization of Non-Utility Property	$ -			
2205	Accounts Payable	-$ 10,979,891.00			
2208	Customer Credit Balances	$ -			
2210	Current Portion of Customer Deposits	-$ 1,125,000.00			
2215	Dividends Declared	$ -			
2220	Miscellaneous Current and Accrued Liabilities	$ -			
2225	Notes and Loans Payable	$ -			
2240	Accounts Payable to Associated Companies	-$ 1,162,800.00			

2242	Notes Payable to Associated Companies	$ -			
2250	Debt Retirement Charges(DRC) Payable	-$ 468,130.00			
2252	Transmission Charges Payable	$ -			
2254	Electrical Safety Authority Fees Payable	$ -			
2256	Independent Market Operator Fees and Penalties Payable	$ -			
2260	Current Portion of Long Term Debt	-$ 1,038,479.00			
2262	Ontario Hydro Debt - Current Portion	$ -			
2264	Pensions and Employee Benefits - Current Portion	$ -			
2268	Accrued Interest on Long Term Debt	-$ 1,419,904.00			
2270	Matured Long Term Debt	$ -			
2272	Matured Interest on Long Term Debt	$ -			
2285	Obligations Under Capital Leases--Current	$ -			
2290	Commodity Taxes	$ -			
2292	Payroll Deductions / Expenses Payable	$ -			
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.	$ 314,176.00			
2296	Future Income Taxes - Current	$ 216,240.00			
2305	Accumulated Provision for Injuries and Damages	$ -			
2306	Employee Future Benefits	-$ 2,167,258.00			
2308	Other Pensions - Past Service Liability	$ -			
2310	Vested Sick Leave Liability	-$ 74,460.00			
2315	Accumulated Provision for Rate Refunds	$ -			
2320	Other Miscellaneous Non-Current Liabilities	$ -			
2325	Obligations Under Capital Lease--Non-Current	$ -			
2330	Development Charge Fund	$ -			
2335	Long Term Customer Deposits	-$ 500,000.00			
2340	Collateral Funds Liability	$ -			
2345	Unamortized Premium on Long Term Debt	$ -			
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion	$ -			
2350	Future Income Tax - Non-Current	$ 379,762.00			
2405	Other Regulatory Liabilities	$ -			
2410	Deferred Gains from Disposition of Utility Plant	$ -			
2415	Unamortized Gain on Reacquired Debt	$ -			
2425	Other Deferred Credits	-$ 1,250,000.00			
2435	Accrued Rate-Payer Benefit	$ -			
2505	Debentures Outstanding - Long Term Portion	$ -			
2510	Debenture Advances	-$ 15,445,714.00			
2515	Reacquired Bonds	$ -			
2520	Other Long Term Debt	-$ 565,957.00			
2525	Term Bank Loans - Long Term Portion	-$ 3,479,000.00			
2530	Ontario Hydro Debt Outstanding - Long Term Portion	$ -			
2550	Advances from Associated Companies	-$ 24,189,168.00			
3005	Common Shares Issued	-$ 22,437,505.00			
3008	Preference Shares Issued	$ -			
3010	Contributed Surplus	$ -			
3020	Donations Received	$ -			
3022	Development Charges Transferred to Equity	$ -			
3026	Capital Stock Held in Treasury	$ -			
3030	Miscellaneous Paid-In Capital	$ -			
3035	Installments Received on Capital Stock	$ -			
3040	Appropriated Retained Earnings	$ 485,837.00			
3045	Unappropriated Retained Earnings	-$ 12,471,066.00			
3046	Balance Transferred From Income	$ -	$0		$0
3047	Appropriations of Retained Earnings - Current Period	$ -			
3048	Dividends Payable-Preference Shares	$ -			
3049	Dividends Payable-Common Shares	$ 750,000.00			
3055	Adjustment to Retained Earnings	$ 973,005.00			
3065	Unappropriated Undistributed Subsidiary Earnings	$ -			
4006	Residential Energy Sales	-$ 23,693,483.00			
4010	Commercial Energy Sales	$ -			
4015	Industrial Energy Sales	$ -			
4020	Energy Sales to Large Users	$ -			
4025	Street Lighting Energy Sales	-$ 667,930.00			
4030	Sentinel Lighting Energy Sales	-$ 39,219.00			
4035	General Energy Sales	-$ 50,903,579.00			
4040	Other Energy Sales to Public Authorities	$ -			
4045	Energy Sales to Railroads and Railways	$ -			
4050	Revenue Adjustment	$ 151,688.00			
4055	Energy Sales for Resale	-$ 3,686,100.00			
4060	Interdepartmental Energy Sales	$ -			
4062	Billed WMS	-$ 5,213,298.00			
4064	Billed-One-Time	$ -			

4066	Billed NW	-$ 6,638,889.00			
4068	Billed CN	-$ 4,375,814.00			
4080	Distribution Services Revenue	-$ 14,365,044.00			
4080-1	Revenue from Rates		$15,096,208		
4080-2	SSS Admin Charge	-$ 165,054.40			
4082	Retail Services Revenues	-$ 38,639.00			
4084	Service Transaction Requests (STR) Revenues	-$ 11,660.00			
4090	Electric Services Incidental to Energy Sales	$ -			
4105	Transmission Charges Revenue	$ -			
4110	Transmission Services Revenue	$ -			
4205	Interdepartmental Rents	$ -			
4210	Rent from Electric Property	-$ 108,120.00			
4215	Other Utility Operating Income	$ -			
4220	Other Electric Revenues	$ -			
4225	Late Payment Charges	-$ 120,000.00			
4230	Sales of Water and Water Power	$ -			
4235	Miscellaneous Service Revenues	-$ 422,134.00			
4235-1	Account Set Up Charges	$ -			
4235-90	Miscellaneous Service Revenues - Residual	-$ 422,134.00			
4240	Provision for Rate Refunds	$ -			
4245	Government Assistance Directly Credited to Income	$ -			
4305	Regulatory Debits	$ -			
4310	Regulatory Credits	$ -			
4315	Revenues from Electric Plant Leased to Others	$ -			
4320	Expenses of Electric Plant Leased to Others	$ -			
4325	Revenues from Merchandise, Jobbing, Etc.	$ -			
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ -			
4335	Profits and Losses from Financial Instrument Hedges	$ -			
4340	Profits and Losses from Financial Instrument Investments	$ -			
4345	Gains from Disposition of Future Use Utility Plant	$ -			
4350	Losses from Disposition of Future Use Utility Plant	$ -			
4355	Gain on Disposition of Utility and Other Property	$ -			
4360	Loss on Disposition of Utility and Other Property	$ -			
4365	Gains from Disposition of Allowances for Emission	$ -			
4370	Losses from Disposition of Allowances for Emission	$ -			
4375	Revenues from Non-Utility Operations	-$ 5,165,361.00			
4380	Expenses of Non-Utility Operations	$ 5,165,361.00			
4385	Non-Utility Rental Income	$ -			
4390	Miscellaneous Non-Operating Income	-$ 20,000.00			
4395	Rate-Payer Benefit Including Interest	$ -			
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -			
4405	Interest and Dividend Income	-$ 275,539.00			
4415	Equity in Earnings of Subsidiary Companies	$ -			
4505	Operation Supervision and Engineering	$ -			
4510	Fuel	$ -			
4515	Steam Expense	$ -			
4520	Steam From Other Sources	$ -			
4525	Steam Transferred--Credit	$ -			
4530	Electric Expense	$ -			
4535	Water For Power	$ -			
4540	Water Power Taxes	$ -			
4545	Hydraulic Expenses	$ -			
4550	Generation Expense	$ -			
4555	Miscellaneous Power Generation Expenses	$ -			
4560	Rents	$ -			
4565	Allowances for Emissions	$ -			
4605	Maintenance Supervision and Engineering	$ -			
4610	Maintenance of Structures	$ -			
4615	Maintenance of Boiler Plant	$ -			
4620	Maintenance of Electric Plant	$ -			
4625	Maintenance of Reservoirs, Dams and Waterways	$ -			
4630	Maintenance of Water Wheels, Turbines and Generators	$ -			
4635	Maintenance of Generating and Electric Plant	$ -			
4640	Maintenance of Miscellaneous Power Generation Plant	$ -			

4705	Power Purchased		$ 78,838,624.00			
4708	Charges-WMS		$ 5,213,298.00			
4710	Cost of Power Adjustments		$ -			
4712	Charges-One-Time		$ -			
4714	Charges-NW		$ 6,638,889.00			
4715	System Control and Load Dispatching		$ -			
4716	Charges-CN		$ 4,375,814.00			
4720	Other Expenses		$ -			
4725	Competition Transition Expense		$ -			
4730	Rural Rate Assistance Expense		$ -			
4750	Charges-LV		$ -			
4805	Operation Supervision and Engineering		$ -			
4810	Load Dispatching		$ -			
4815	Station Buildings and Fixtures Expenses		$ -			
4820	Transformer Station Equipment - Operating Labour		$ -			
4825	Transformer Station Equipment - Operating Supplies and Expense		$ -			
4830	Overhead Line Expenses		$ -			
4835	Underground Line Expenses		$ -			
4840	Transmission of Electricity by Others		$ -			
4845	Miscellaneous Transmission Expense		$ -			
4850	Rents		$ -			
4905	Maintenance Supervision and Engineering		$ -			
4910	Maintenance of Transformer Station Buildings and Fixtures		$ -			
4916	Maintenance of Transformer Station Equipment		$ -			
4930	Maintenance of Towers, Poles and Fixtures		$ -			
4935	Maintenance of Overhead Conductors and Devices		$ -			
4940	Maintenance of Overhead Lines - Right of Way		$ -			
4945	Maintenance of Overhead Lines - Roads and Trails Repairs		$ -			
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails		$ -			
4960	Maintenance of Underground Lines		$ -			
4965	Maintenance of Miscellaneous Transmission Plant		$ -			
5005	Operation Supervision and Engineering		$ 273,250.00			
5010	Load Dispatching		$ 114,745.00			
5012	Station Buildings and Fixtures Expense		$ 29,322.00			
5014	Transformer Station Equipment - Operation Labour		$ 24,787.00			
5015	Transformer Station Equipment - Operation Supplies and Expenses		$ 102,609.00			
5016	Distribution Station Equipment - Operation Labour		$ 1,962.00			
5017	Distribution Station Equipment - Operation Supplies and Expenses		$ 520.00			
5020	Overhead Distribution Lines and Feeders - Operation Labour		$ 1,962.00			
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		$ 12,752.00			
5030	Overhead Subtransmission Feeders - Operation		$ -			
5035	Overhead Distribution Transformers- Operation		$ 5,154.00			
5040	Underground Distribution Lines and Feeders - Operation Labour		$ -			
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses		$ 11,990.00			
5050	Underground Subtransmission Feeders - Operation		$ -			
5055	Underground Distribution Transformers - Operation		$ -			
5060	Street Lighting and Signal System Expense		$ -			
5065	Meter Expense		$ 593,094.00			
5070	Customer Premises - Operation Labour		$ 5,292.00			
5075	Customer Premises - Materials and Expenses		$ -			
5085	Miscellaneous Distribution Expense		$ 329,209.00			
5090	Underground Distribution Lines and Feeders - Rental Paid		$ -			
5095	Overhead Distribution Lines and Feeders - Rental Paid		$ 25,403.00			
5096	Other Rent		$ 44,455.00			
5105	Maintenance Supervision and Engineering		$ 499,599.00			
5110	Maintenance of Buildings and Fixtures - Distribution Stations		$ 2,158.00			

5112	Maintenance of Transformer Station Equipment	$ -			
5114	Maintenance of Distribution Station Equipment	$ 9,805.00			
5120	Maintenance of Poles, Towers and Fixtures	$ 75,414.00			
5125	Maintenance of Overhead Conductors and Devices	$ 242,022.00			
5130	Maintenance of Overhead Services	$ 247,604.00			
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 499,535.00			
5145	Maintenance of Underground Conduit	$ 56,902.00			
5150	Maintenance of Underground Conductors and Devices	$ 82,311.00			
5155	Maintenance of Underground Services	$ 124,877.00			
5160	Maintenance of Line Transformers	$ 192,863.00			
5165	Maintenance of Street Lighting and Signal Systems	$ -			
5170	Sentinel Lights - Labour	$ -			
5172	Sentinel Lights - Materials and Expenses	$ -			
5175	Maintenance of Meters	$ -			
5178	Customer Installations Expenses- Leased Property	$ -			
5185	Water Heater Rentals - Labour	$ -			
5186	Water Heater Rentals - Materials and Expenses	$ -			
5190	Water Heater Controls - Labour	$ -			
5192	Water Heater Controls - Materials and Expenses	$ -			
5195	Maintenance of Other Installations on Customer Premises	$ -			
5205	Purchase of Transmission and System Services	$ -			
5210	Transmission Charges	$ -			
5215	Transmission Charges Recovered	$ -			
5305	Supervision	$ 292,372.00			
5310	Meter Reading Expense	$ 240,556.00			
5315	Customer Billing	$ 964,616.00			
5320	Collecting	$ 536,496.00			
5325	Collecting- Cash Over and Short	$ -			
5330	Collection Charges	$ 500.00			
5335	Bad Debt Expense	$ 306,000.00			
5340	Miscellaneous Customer Accounts Expenses	$ 522,675.00			
5405	Supervision	$ -			
5410	Community Relations - Sundry	$ 152,526.00			
5415	Energy Conservation	$ -			
5420	Community Safety Program	$ 19,051.00			
5425	Miscellaneous Customer Service and Informational Expenses	$ 61,200.00			
5505	Supervision	$ -			
5510	Demonstrating and Selling Expense	$ -			
5515	Advertising Expense	$ -			
5520	Miscellaneous Sales Expense	$ -			
5605	Executive Salaries and Expenses	$ 729,401.00			
5610	Management Salaries and Expenses	$ 384,158.00			
5615	General Administrative Salaries and Expenses	$ 582,990.00			
5620	Office Supplies and Expenses	$ 80,250.00			
5625	Administrative Expense Transferred Credit	$ -			
5630	Outside Services Employed	$ 220,000.00			
5635	Property Insurance	$ 133,133.00			
5640	Injuries and Damages	$ -			
5645	Employee Pensions and Benefits	$ 108,000.00			
5650	Franchise Requirements	$ 59,000.00			
5655	Regulatory Expenses	$ 144,500.00			
5660	General Advertising Expenses	$ 40,000.00			
5665	Miscellaneous General Expenses	-$ 1,995.00			
5670	Rent	$ -			
5675	Maintenance of General Plant	$ -			
5680	Electrical Safety Authority Fees	$ 19,000.00			
5681	IFRS Placeholder Expense Account	$ -			
5682	IFRS Placeholder Expense Account	$ -			
5683	IFRS Placeholder Expense Account	$ -			
5684	IFRS Placeholder Expense Account	$ -			
5685	Independent Market Operator Fees and Penalties	$ -			
5705	Amortization Expense - Property, Plant, and Equipment	$ 2,995,583.74			
5710	Amortization of Limited Term Electric Plant	$ -			
5715	Amortization of Intangibles and Other Electric Plant	$ -			

5720	Amortization of Electric Plant Acquisition Adjustments		$ -			
5725	Miscellaneous Amortization		$ -			
5730	Amortization of Unrecovered Plant and Regulatory Study Costs		$ -			
5735	Amortization of Deferred Development Costs		$ -			
5740	Amortization of Deferred Charges		$ -			
6005	Interest on Long Term Debt		$ 921,760.00	-$921,760		$0
6010	Amortization of Debt Discount and Expense		$ -			
6015	Amortization of Premium on Debt Credit		$ -			
6020	Amortization of Loss on Reacquired Debt		$ -			
6025	Amortization of Gain on Reacquired Debt--Credit		$ -			
6030	Interest on Debt to Associated Companies		$ 1,419,904.00			
6035	Other Interest Expense		$ 135,144.00			
6040	Allowance for Borrowed Funds Used During Construction--Credit		$ -			
6042	Allowance For Other Funds Used During Construction		$ -			
6045	Interest Expense on Capital Lease Obligations		$ -			
6105	Taxes Other Than Income Taxes		$ 12,000.00			
6110	Income Taxes		-$ 783,636.00	$783,636		$0
6115	Provision for Future Income Taxes		$ 916,580.00			
6205	Donations		$ -			
6210	Life Insurance		$ -			
6215	Penalties		$ -			
6225	Other Deductions		$ -			
6305	Extraordinary Income		$ -			
6310	Extraordinary Deductions		$ -			
6315	Income Taxes, Extraordinary Items		$ -			
6405	Discontinues Operations - Income/ Gains		$ -			
6410	Discontinued Operations - Deductions/ Losses		$ -			
6415	Income Taxes, Discontinued Operations		$ -			

$0

Reclassification Equals to Zero. O.K. to Proceed.

Asset Accounts Directly Allocated	$0

Differences?

Rev Req Matches

Rate Base Matches

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2013 Cost Allocation Model

Sheet I4 Break Out Worksheet - 1-Staff-2 Updated Cost Allocation Study

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	**$63,834,314**

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS								
						-536255.039				
Account	**Description**	**Break out Functions**	**BREAK OUT (%)**	**BREAK OUT ($)**	**After BO**	**Contributed Capital - 1995**	**Accumulated Depreciation - 2105 Capital Contribution**	**Accumulated Depreciation - 2105 Fixed Assets Only**	**Accumulated Depreciation - 2120**	**Asset net of Accumulated Depreciation and Contributed Capital**
1565	Conservation and Demand Management	$0		-	-					-
1805	Land	$181,961		-$181,961	-					
1805-1	Land Station >50 kV			$0	-					-
1805-2	Land Station <50 kV		100.00%	$181,961	181,961					181,961
1806	Land Rights	$94,991		-$94,991	-					
1806-1	Land Rights Station >50 kV			$0	-					-
1806-2	Land Rights Station <50 kV		100.00%	$94,991	94,991			$ (8,395)		86,595
1808	Buildings and Fixtures	$1,163,732		-$1,163,732	-					
1808-1	Buildings and Fixtures > 50 kV			$0	-					-
1808-2	Buildings and Fixtures < 50 KV		100.00%	$1,163,732	1,163,732			$ (208,075)		955,657
1810	Leasehold Improvements	$0		$0	-					
1810-1	Leasehold Improvements >50 kV			$0	-					-
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-
1815	Transformer Station Equipment - Normally Primary above 50 kV	$4,507,912		$0	4,507,912			$ (945,583)		3,562,329
1820	Distribution Station Equipment - Normally Primary below 50 kV	$74,427		-$74,427	-					-
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			$0	-					-
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		50.00%	$37,213	37,213			$ (15,402)		21,811
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		50.00%	$37,213	37,213			$ (15,402)		21,811
1825	Storage Battery Equipment	$0		$0	-					
1825-1	Storage Battery Equipment > 50 kV			$0	-					-
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-					-
1830	Poles, Towers and Fixtures	$17,073,916		-$17,073,916	-					

2013 Cost Allocation Model

Sheet I4 Break Out Worksheet - 1-Staff-2 Updated Cost Allocation Study

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	**$63,834,314**

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS								
						-536255.039				
Account	**Description**	**Break out Functions**	**BREAK OUT (%)**	**BREAK OUT ($)**	**After BO**	**Contributed Capital - 1995**	**Accumulated Depreciation - 2105 Capital Contribution**	**Accumulated Depreciation - 2105 Fixed Assets Only**	**Accumulated Depreciation - 2120**	**Asset net of Accumulated Depreciation and Contributed Capital**
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-	-				-
1830-4	Poles, Towers and Fixtures - Primary		82.00%	$14,000,611	14,000,611	(696,729)	139,984.02	$ (5,434,932)		8,008,934
1830-5	Poles, Towers and Fixtures - Secondary		18.00%	$3,073,305	3,073,305	(152,940)	30,728	$ (1,193,034)		1,758,059
1835	Overhead Conductors and Devices	$13,029,744		-$13,029,744	-	-				
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-	-				-
1835-4	Overhead Conductors and Devices - Primary		71.00%	$9,251,118	9,251,118	(460,374)	92,497	$ (3,191,514)		5,691,726
1835-5	Overhead Conductors and Devices - Secondary		29.00%	$3,778,626	3,778,626	(188,040)	37,780	$ (1,303,576)		2,324,790
1840	Underground Conduit	$13,876,033		-$13,876,033	-	-				
1840-3	Underground Conduit - Bulk Delivery			$0	-	-				-
1840-4	Underground Conduit - Primary		19.00%	$2,636,446	2,636,446	(131,201)	26,360	$ (1,034,440)		1,497,167
1840-5	Underground Conduit - Secondary		81.00%	$11,239,587	11,239,587	(559,329)	112,378	$ (4,409,979)		6,382,658
1845	Underground Conductors and Devices	$19,021,892		-$19,021,892	-	-				
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-	-				-
1845-4	Underground Conductors and Devices - Primary		51.00%	$9,701,165	9,701,165	(482,770)	96,996.34	$ (2,605,430)		6,709,960
1845-5	Underground Conductors and Devices - Secondary		49.00%	$9,320,727	9,320,727	(463,838)	93,193	$ (2,503,257)		6,446,825
1850	Line Transformers	$17,634,772		$0	17,634,772	(877,580)	176,320	$ (6,589,032)		10,344,480
1855	Services	$1,618,785		$0	1,618,785	(80,557)	16,185	$ (298,776)		1,255,636
1860	Meters	$9,353,846		$0	9,353,846	(465,486)	93,524	$ (2,374,687)		6,607,197
9999	IFRS Placeholder Account	$0		$0	-					-

2013 Cost Allocation Model

Sheet I4 Break Out Worksheet - 1-Staff-2 Updated Cost Allocation Study

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	$63,834,314

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS								
						-536255.039				
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
	Total	$97,632,009		$0	$97,632,009	-$4,558,844	$915,945	-$32,131,514	$0	61,857,596
	SUB TOTAL from I3	$97,632,009								

2013 Cost Allocation Model

Sheet I4 Break Out Worksheet - 1-Staff-2 Updated Cost Allocation Study

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	$63,834,314

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS								
						-536255.039				
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset
1905	Land	$0			-			$ -		$ -
1906	Land Rights	$0			-			$ -		$ -
1908	Buildings and Fixtures	$0			-			$ -		$ -
1910	Leasehold Improvements	$0			-			$ -		$ -
1915	Office Furniture and Equipment	$3,113			3,113			$ (564)		$ 2,549
1920	Computer Equipment - Hardware	$184,129			184,129			$ (63,963)		$ 120,166
1925	Computer Software	$792,431			792,431			$ (387,455)		$ 404,977
1930	Transportation Equipment	$3,028,990			3,028,990			$ (2,213,665)		$ 815,324
1935	Stores Equipment	$0			-			$ -		$ -
1940	Tools, Shop and Garage Equipment	$156,492			156,492			$ (82,566)		$ 73,926
1945	Measurement and Testing Equipment	$0			-			$ -		$ -
1950	Power Operated Equipment	$0			-			$ -		$ -
1955	Communication Equipment	$0			-			$ -		$ -
1960	Miscellaneous Equipment	$0			-			$ -		$ -
1970	Load Management Controls - Customer Premises	$0			-			$ -		$ -
1975	Load Management Controls - Utility Premises	$0			-			$ -		$ -
1980	System Supervisory Equipment	$772,337			772,337			$ (212,562)		$ 559,775
1990	Other Tangible Property	$0			-			$ -		$ -
2005	Property Under Capital Leases	$0			-			$ -		$ -
2010	Electric Plant Purchased or Sold	$0			-			$ -		$ -
	Total	$4,937,492		$0	$4,937,492	$0	$0	$ (2,960,774)	$0	$1,976,718
	SUB TOTAL from I3	$4,937,492								
	I3 Directly Allocated	$0								
	Grand Total	$102,569,501		$0	$102,569,501	-$4,558,844	$915,945	-$35,092,288.56	$0	$63,834,314

2013 Cost Allocation Model

Sheet I4 Break Out Worksheet - 1-Staff-2 Updated Cost Allocation Study

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	$63,834,314

RATE BASE AND DISTRIBUTION ASSETS

BALANCE SHEET ITEMS

-536255.039

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
To be Prorated										
1995	Contributed Capital - 1995	-$4,558,844				$4,558,844	Balanced			
2105	Accumulated Depreciation - 2105	-$34,176,343						$34,176,343	Balanced	
2120	Accumulated Depreciation - 2120	$0							$0	Balanced
	Total	**-$38,735,187**								
	Net Assets	**$63,834,314**	**Net Fixed Assets Match**	$0						

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$2,995,584
5710	Amortization of Limited Term Electric Plant	$0
5715	Amortization of Intangibles and Other Electric Plant	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0
	Total Amortization Expense	**$2,995,584**

Sheet I4 Break

Instructions:
This is an input sheet for the Break Out (
*****Please see Instructions tab for detailed***

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS			
		5705	5710	5715	5720
Account	**Description**	**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**
1565	Conservation and Demand Management				
1805	Land				
1805-1	Land Station >50 kV				
1805-2	Land Station <50 kV				
1806	Land Rights				
1806-1	Land Rights Station >50 kV				
1806-2	Land Rights Station <50 kV	$1,294			
1808	Buildings and Fixtures				
1808-1	Buildings and Fixtures > 50 kV				
1808-2	Buildings and Fixtures < 50 KV	27,086.00			
1810	Leasehold Improvements				
1810-1	Leasehold Improvements >50 kV				
1810-2	Leasehold Improvements <50 kV				
1815	Transformer Station Equipment - Normally Primary above 50 kV	104,104.00			
1820	Distribution Station Equipment - Normally Primary below 50 kV				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)	780.00			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	780.00			
1825	Storage Battery Equipment				
1825-1	Storage Battery Equipment > 50 kV				
1825-2	Storage Battery Equipment <50 kV				
1830	Poles, Towers and Fixtures				

	Accumulated Depreciation	Depreciation
1805	-	-
1806	8,395.42	1,294.00
1808	208,074.90	27,086.00
1810	-	-
1815	945,582.57	104,104.00
1820	30,804.51	1,560.00
1825	-	-
1830	6,627,966.33	374,253.00

Sheet I4 Break

Instructions:
This is an input sheet for the Break Out (
*****Please see Instructions tab for detailed***

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS						
		5705	5710	5715	5720		Accumulated Depreciation	Depreciation
Account	**Description**	**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**			
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery							
1830-4	Poles, Towers and Fixtures - Primary	$290,725						
1830-5	Poles, Towers and Fixtures - Secondary	$63,818						
1835	Overhead Conductors and Devices					1835	4,495,090.64	243,122.00
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery							
1835-4	Overhead Conductors and Devices - Primary	$161,937						
1835-5	Overhead Conductors and Devices - Secondary	$66,143						
1840	Underground Conduit					1840	5,444,418.43	233,392.00
1840-3	Underground Conduit - Bulk Delivery							
1840-4	Underground Conduit - Primary	$41,301						
1840-5	Underground Conduit - Secondary	$176,073						
1845	Underground Conductors and Devices					1845	5,108,686.96	640,974.00
1845-3	Underground Conductors and Devices - Bulk Delivery							
1845-4	Underground Conductors and Devices - Primary	$315,698						
1845-5	Underground Conductors and Devices - Secondary	$303,317						
1850	Line Transformers	$426,682				1850	6,589,031.92	447,040.00
1855	Services	$54,192				1855	298,776.27	56,061.00
1860	Meters	$772,367				1860	2,374,686.52	783,165.38
9999	IFRS Placeholder Account							

Sheet I4 Break

Instructions:
This is an input sheet for the Break Out
*****Please see Instructions tab for detailed***

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS			
		5705	5710	5715	5720
Account	Description	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
	Total	$2,806,298	$0	$0	$0
	SUB TOTAL from I3				
		5705	5710	5715	5720

	Accumulated Depreciation	Depreciation

Sheet I4 Break

Instructions:
This is an input sheet for the Break Out
*****Please see Instructions tab for detailed***

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS			
		5705	5710	5715	5720
Account	**Description**	**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**
General Plant		**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**
1905	Land	-			
1906	Land Rights	-			
1908	Buildings and Fixtures	-			
1910	Leasehold Improvements	-			
1915	Office Furniture and Equipment	500.00			
1920	Computer Equipment - Hardware	18,325.73			
1925	Computer Software	121,073.62			
1930	Transportation Equipment	-			
1935	Stores Equipment	-			
1940	Tools, Shop and Garage Equipment	17,781.00			
1945	Measurement and Testing Equipment	-			
1950	Power Operated Equipment	-			
1955	Communication Equipment	-			
1960	Miscellaneous Equipment	-			
1970	Load Management Controls - Customer Premises	-			
1975	Load Management Controls - Utility Premises	-			
1980	System Supervisory Equipment	31,605.00			
1990	Other Tangible Property	-			
2005	Property Under Capital Leases	-			
2010	Electric Plant Purchased or Sold	-			
	Total	189,285.36	$0	$0	$0
	SUB TOTAL from I3 I3 Directly Allocated				
	Grand Total	$2,995,584	$0	$0	$0

	Accumulated Depreciation	Depreciation
1905	-	-
1906	-	-
1908	-	-
1910	-	-
1915	564.00	500.00
1920	63,962.75	18,325.73
1925	387,454.73	121,073.62
1930	2,213,665.24	-
1935	-	-
1940	82,565.66	17,781.00
1945	-	-
1950	-	-
1955	-	-
1960	-	-
1970	-	-
1975	-	-
1980	212,561.71	31,605.00
1990	-	-
2005	-	-
2010	-	-
	35,092,289	3,101,337

Sheet I4 Break

Instructions:
This is an input sheet for the Break Out
*****Please see Instructions tab for detailed***

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS				
		5705	5710	5715	5720	
Account	**Description**	**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**	
To be Prorated						
1995	Contributed Capital - 1995					
2105	Accumulated Depreciation - 2105					
2120	Accumulated Depreciation - 2120					
	Total					
	Net Assets					
Amortization Expenses						
5705	Amortization Expense - Property, Plant, and Equipment	-$2,995,583.74	**Balanced**			
5710	Amortization of Limited Term Electric Plant		$0	**Balanced**		
5715	Amortization of Intangibles and Other Electric Plant			$0	**Balanced**	
5720	Amortization of Electric Plant Acquisition Adjustments				$0	**Balanced**
	Total Amortization Expense					

	Accumulated Depreciation	Depreciation
	-915945.37	-105753
	34,176,343	-161947
		2,833,637

Sheet I5.1 Miscellaneous Data Worksheet - 1

kMs of Roads in Service Area Where Distribution Lines Exist	828.9
Deemed Equity Component of Rate Base (%)	40%
Working Capital Allowance to be included in Rate Base	13%
Portion of pole leasing revenue from Secondary - Remainder assumed to be Primary (%)	21%

	1	2	3
	Residential	GS <50	GS>50-Regular
Insert Approved Monthly Service Charge	11.46	24.81	293.71

Allocation Model

ı-Staff-2 Updated Cost Allocation Study

7	8	9	10	
Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	
0.65	2.32	12.06	293.71	

2013 Cost Allo

Sheet I5.2 Weighting Factors Worksheet - 1-Staff-2

	1	2	3
	Residential	GS <50	GS>50-Regular
Insert Weighting Factor for Services	1.0	0.6	0.7
Insert Weighting Factor for Billing and Collecting	1.0	2.0	8.0

cation Model

Updated Cost Allocation Study

7	8	9	10
Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
0.0	0.0	0.0	0.0
1.0	1.0	1.0	1.0

2013 Cost Allocation Model

Sheet I6.1 Revenue Worksheet - 1-Staff-2 Updated Cost Allocation Study

Total kWhs from Load Forecast	899,549,721
Total kWs from Load Forecast	1,513,478
Deficiency from RRWF	- 1,537,106
Miscellaneous Revenue	1,161,146

			1	2	3	7	8	9	10
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Billing Data									
Forecast kWh	**CEN**	899,549,721	272,082,836	94,447,805	523,567,859	7,553,004	443,490	1,454,727	
Forecast kW	**CDEM**	1,513,478			1,332,860	23,455	1,356		155,806
Forecast kW, included in CDEM, of customers receiving line transformer allowance		738,729		210.4	738,519				
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	899,536,575	272,082,836	94,447,805	523,554,713	7,553,004	443,490	1,454,727	-
kWh - 30 year weather normalized amount		899,549,721	272,082,836	94,447,805	523,567,859	7,553,004	443,490	1,454,727	-
Existing Monthly Charge			$11.46	$24.81	$293.71	$0.65	$2.32	$12.06	$293.71
Existing Distribution kWh Rate			$0.0138	$0.0065				$0.0072	
Existing Distribution kW Rate					$2.6043	$2.7127	$11.1228		$1.7488
Existing TFOA Rate				$0.60	$0.60				
Additional Charges									

Distribution Revenue from Rates		$15,539,445	$8,617,961	$1,436,837	$4,950,690	$144,395	$32,766	$73,750	$283,047
Transformer Ownership Allowance		$443,238	$0	$126	$443,111	$0	$0	$0	$0
Net Class Revenue	**CREV**	$15,096,208	$8,617,961	$1,436,711	$4,507,578	$144,395	$32,766	$73,750	$283,047
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		14,813,161	8,617,961	1,436,711	4,507,578	144,395	32,766	73,750	-

Weather Normalized Data from Hydro One

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
kWh - 30 year weather normalized amount	899,549,721	272,082,836	94,447,805	523,567,859	7,553,004	443,490	1,454,727	-
Loss Factor		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**

2013 Cost Allocation Model

Sheet I6.2 Customer Data Worksheet - 1-Staff-2 Updated Cost Allocation Study

			1	2	3	7	8	9	10
	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$202,766	$155,822	$15,348	$31,251	$0	$345	$0	$0
Late Payment 3 Year Historical Average	LPHA	$136,110	$110,129	$11,033	$14,823	$0	$16	$109	
Number of Bills	CNB	461,545	415,449	32,465.00	5,038	12	3,240	5,329	12
Number of Devices						10,355	635	437	
Number of Connections (Unmetered)	CCON	1,718				645	635	437	
Total Number of Customers	CCA	38,842	35,364	2,764	420	1	270	20	3
Bulk Customer Base	CCB	38,842	35,364	2,764	420	1	270	20	3
Primary Customer Base	CCP	38,842	35,364	2,764	420	1	270	20	3
Line Transformer Customer Base	CCLT	38,771	35,364	2,757	359	1	270	20	
Secondary Customer Base	CCS	38,819	35,364	2,764	400	1	270	20	
Weighted - Services	CWCS	37,373	35,364	1,741	268	-	-	-	-
Weighted Meter -Capital	CWMC	6,714,938	3,995,867	1,410,508	1,308,563	-	-	-	-
Weighted Meter Reading	CWMR	40,150	35,364	2,855	1,932	-	-	-	-
Weighted Bills	CWNB	529,276	415,449	64,930	40,304	12	3,240	5,329	12

Bad Debt Data

Historic Year:	2009	209,072	155,080	19,068	33,889		1,035		
Historic Year:	2010	157,457	141,698	9,768	5,991				
Historic Year:	2011	241,770	170,686	17,210	53,874				
Three-year average		**202,766**	**155,822**	**15,348**	**31,251**	**-**	**345**	**-**	**-**

2013 Cost Allocation Model

Sheet I7.1 Meter Capital Worksheet - 1-Staff-2 Updated Cost Allocation Study

		Residential			GS <50			GS>50-Regular			Street Light	
		1	2	3	1	2	3	1	2	3	1	2
		Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs
	Allocation Percentage Weighted Factor			59.51%			21%			19%		
	Cost Relative to Residential Average Cost			1.00			4.52			27.59		
	Total	35364	3995866.747	$ 112.99	2764	1410508.156	$ 510.30	420	1308562.902	$ 3,117.26	0	0
Meter Types	**Cost per Meter (Installed)**											
Single Phase 200 Amp - Urban	$ 121.00	42	5082		7	847			0			0
Single Phase 200 Amp - Rural			0			0			0			0
Central Meter	$ 250.00	21	5250		154	38500		2	500			0
Network Meter (Costs to be updated)			0			0			0			0
Three-phase - No demand	$ 631.00		0		17	10727		16	10096			0
Smart Meters	$ 109.00	33,984	3704224.747		748	81532			0			0
Demand without IT (usually three-phase)	$ 709.00		0		7	4963		18	12762			0
Demand with IT	$ 1,891.00		0		4	7564		28	52948			0
Demand with IT and Interval Capability - Secondary	$ 2,491.00		0		20	49820		342	851372.9017			0
Demand with IT and Interval Capability - Primary	$ 27,206.00		0			0		14	380884			0
Demand with IT and Interval Capability -Special (WMP)			0			0			0			0
Smart Meters - Network Meter	$ 211.00	1,310	276410		99	20889			0			0
Smart Meters -Three Phase No Demand	$ 700.00	7	4900		1,708	1195666.156			0			0
LDC Specific 3			0			0			0			0

	Sentinel			Unmetered Scattered Load			Embedded Distributor			TOTAL		
3	1	2	3	1	2	3	1	2	3	1	2	3
Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)
0%			0%			0%			0%			100%
-			-			-			-			1.54
-	0	0	-	0	0	-	0	0	-	38547.58735	6714937.805	174.1986533
		0			0			0		49	5929	
		0			0			0		0	0	
		0			0			0		177	44250	
		0			0			0		0	0	
		0			0			0		33	20823	
		0			0			0		34,732	3785756.747	
		0			0			0		25	17725	
		0			0			0		32	60512	
		0			0			0		362	901192.9017	
		0			0			0		14	380884	
		0			0			0		0	0	
		0			0			0		1,409	297299	
		0			0			0		1,715	1200566.156	
		0			0			0		0	0	

Sheet I7.2 Meter Reading Worksheet - 1-Staff-2 Updated Cost Allocation Study

Weighting Factors based on Contractor Pricing

Description		1			2			3			7			8	
		Residential			GS <50			GS>50-Regular			Street Light			Sentinel	
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor
	Allocation Percentage Weighted Factor			88.08%			7.11%			4.81%			0.00%		
	Cost Relative to Residential Average Cost			1.00			1.03			4.60			0.00		
	Total	35,364	35,364	1.00	2,764	2,855	1.03	420	1,932	4.60	-	-	0	-	-
	Factor														
Residential - Urban - Outside			0			0			0			0			0
Residential - Urban - Outside with other services			0			0			0			0			0
Residential - Urban - Inside			0			0			0			0			0
Residential - Urban - Inside - with other services			0			0			0			0			0
Residential - Rural - Outside		0	0			0			0			0			0
Residential - Rural - Outside with other services		0	0			0			0			0			0
Smart Meter	1.00	35,364	35,364		2,733	2,733			0			0			0
Smart Meter with Demand			0			0			0			0			0
GS - Walking			0			0			0			0			0
GS - Walking - with other services			0			0			0			0			0
GS - Vehicle with other services --- TOU Read			0			0			0			0			0
GS - Vehicle with other services	2.00		0		21	42		238	476			0			0
LDC Specific 3			0			0			0			0			0
LDC Specific 4			0			0			0			0			0
Interval	8.00		0		10	80		182	1,456			0			0
LDC Specific 5			0			0			0			0			0
LDC Specific 6			0			0			0			0			0

	9			10					
	Unmetered Scattered Load			**Embedded Distributor**			**TOTAL**		
Weighted Average Costs	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**
0.00%			0.00%			0.00%			100.00%
0.00			0.00			0.00			6.63
0	**-**	**-**	**0**	**-**	**-**	**0**	**38,548**	**40,150**	**7**
		0			0		-	-	
		0			0		-	-	
		0			0		-	-	
		0			0		-	-	
		0			0		-	-	
		0			0		-	-	
		0			0		38,097	38,097	
		0			0		-	-	
		0			0		-	-	
		0			0		-	-	
		0			0		-	-	
		0			0		259	518	
		0			0		-	-	
		0			0		-	-	
		0			0		192	1,536	
		0			0		-	-	
		0			0		-	-	

Sheet I8 Demand Data Worksheet - 1-Staff-2 Updated Cost Allocation Study

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	177,088	59,019	19,289	85,419	-	-	144	13,216
Bulk Delivery CP	BCP1	177,088	59,019	19,289	85,419	-	-	144	13,216
Total Sytem CP	DCP1	177,088	59,019	19,289	85,419	-	-	144	13,216
4 CP									
Transformation CP	TCP4	658,366	220,148	65,538	320,948	315	17	572	50,827
Bulk Delivery CP	BCP4	658,366	220,148	65,538	320,948	315	17	572	50,827
Total Sytem CP	DCP4	658,366	220,148	65,538	320,948	315	17	572	50,827
12 CP									
Transformation CP	TCP12	1,797,004	569,922	182,295	894,915	6,882	331	1,800	140,860
Bulk Delivery CP	BCP12	1,797,004	569,922	182,295	894,915	6,882	331	1,800	140,860
Total Sytem CP	DCP12	1,797,004	569,922	182,295	894,915	6,882	331	1,800	140,860
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	194,256	64,862	21,962	90,813	2,144	178	250	14,047
Primary NCP	PNCP1	194,256	64,862	21,962	90,813	2,144	178	250	14,047
Line Transformer NCP	LTNCP1	166,957	64,862	21,906	77,617	2,144	178	250.17	
Secondary NCP	SNCP1	175,883	64,862	21,962	86,487	2,144	178	250	
4 NCP									
Classification NCP from Load Data Provider	DNCP4	734,514	242,696	83,202	343,107	8,513	616	950	55,430
Primary NCP	PNCP4	734,514	242,696	83,202	343,107	8,513	616	950	55,430
Line Transformer NCP	LTNCP4	629,015	242,696	82,991	293,248	8,513	616	950	
Secondary NCP	SNCP4	662,737	242,696	83,202	326,760	8,513	616	950	
12 NCP									
Classification NCP from Load Data Provider	DNCP12	1,999,073	633,376	212,309	969,815	23,825	1,460	2,482	155,805
Primary NCP	PNCP12	1,999,073	633,376	212,309	969,815	23,825	1,460	2,482	155,805
Line Transformer NCP	LTNCP12	1,701,802	633,376	211,772	828,887	23,825	1,460	2,482	
Secondary NCP	SNCP12	1,797,062	633,376	212,309	923,609	23,825	1,460	2,482	

Sheet I9 Direct Allocation Worksheet - .

Instructions:
More Instructions provided on the first tab in this workbook.

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?

Instructions:
To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line

1995	Contributions and Grants - Credit	$0	Yes

Instructions:
The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications

1805	Land	$0	Yes
1806	Land Rights	$0	Yes
1808	Buildings and Fixtures	$0	Yes
1810	Leasehold Improvements	$0	Yes
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes
1825	Storage Battery Equipment	$0	Yes
1830	Poles, Towers and Fixtures	$0	Yes
1835	Overhead Conductors and Devices	$0	Yes
1840	Underground Conduit	$0	Yes
1845	Underground Conductors and Devices	$0	Yes
1850	Line Transformers	$0	Yes
1855	Services	$0	Yes
1860	Meters	$0	Yes
9999	IFRS Placeholder Asset Account	$0	Yes
1905	Land	$0	Yes
1906	Land Rights	$0	Yes

1908	Buildings and Fixtures	$0	**Yes**
1910	Leasehold Improvements	$0	**Yes**
1915	Office Furniture and Equipment	$0	**Yes**
1920	Computer Equipment - Hardware	$0	**Yes**
1925	Computer Software	$0	**Yes**
1930	Transportation Equipment	$0	**Yes**
1935	Stores Equipment	$0	**Yes**
1940	Tools, Shop and Garage Equipment	$0	**Yes**
1945	Measurement and Testing Equipment	$0	**Yes**
1950	Power Operated Equipment	$0	**Yes**
1955	Communication Equipment	$0	**Yes**
1960	Miscellaneous Equipment	$0	**Yes**
1970	Load Management Controls - Customer Premises	$0	**Yes**
1975	Load Management Controls - Utility Premises	$0	**Yes**
1980	System Supervisory Equipment	$0	**Yes**
1990	Other Tangible Property	$0	**Yes**
2005	Property Under Capital Leases	$0	**Yes**
2010	Electric Plant Purchased or Sold	$0	**Yes**
2050	Completed Construction Not Classified--Electric	$0	**Yes**
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	$0	**Yes**
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	**Yes**
	Directly Allocated Net Fixed Assets		
5005	Operation Supervision and Engineering	$0	**Yes**
5010	Load Dispatching	$0	**Yes**
5012	Station Buildings and Fixtures Expense	$0	**Yes**
5014	Transformer Station Equipment - Operation Labour	$0	**Yes**
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	**Yes**
5016	Distribution Station Equipment - Operation Labour	$0	**Yes**
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	**Yes**
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	**Yes**
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	**Yes**
5030	Overhead Subtransmission Feeders - Operation	$0	**Yes**
5035	Overhead Distribution Transformers- Operation	$0	**Yes**
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	**Yes**
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	**Yes**

5050	Underground Subtransmission Feeders - Operation	$0	**Yes**
5055	Underground Distribution Transformers - Operation	$0	**Yes**
5065	Meter Expense	$0	**Yes**
5070	Customer Premises - Operation Labour	$0	**Yes**
5075	Customer Premises - Materials and Expenses	$0	**Yes**
5085	Miscellaneous Distribution Expense	$0	**Yes**
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	**Yes**
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	**Yes**
5096	Other Rent	$0	**Yes**
5105	Maintenance Supervision and Engineering	$0	**Yes**
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	**Yes**
5112	Maintenance of Transformer Station Equipment	$0	**Yes**
5114	Maintenance of Distribution Station Equipment	$0	**Yes**
5120	Maintenance of Poles, Towers and Fixtures	$0	**Yes**
5125	Maintenance of Overhead Conductors and Devices	$0	**Yes**
5130	Maintenance of Overhead Services	$0	**Yes**
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	**Yes**
5145	Maintenance of Underground Conduit	$0	**Yes**
5150	Maintenance of Underground Conductors and Devices	$0	**Yes**
5155	Maintenance of Underground Services	$0	**Yes**
5160	Maintenance of Line Transformers	$0	**Yes**
5175	Maintenance of Meters	$0	**Yes**
5305	Supervision	$0	**Yes**
5310	Meter Reading Expense	$0	**Yes**
5315	Customer Billing	$0	**Yes**
5320	Collecting	$0	**Yes**
5325	Collecting- Cash Over and Short	$0	**Yes**
5330	Collection Charges	$0	**Yes**
5335	Bad Debt Expense	$0	**Yes**
5340	Miscellaneous Customer Accounts Expenses	$0	**Yes**
5405	Supervision	$0	**Yes**
5410	Community Relations - Sundry	$0	**Yes**
5415	Energy Conservation	$0	**Yes**
5420	Community Safety Program	$0	**Yes**
5425	Miscellaneous Customer Service and Informational Expenses	$0	**Yes**
5505	Supervision	$0	**Yes**
5510	Demonstrating and Selling Expense	$0	**Yes**
5515	Advertising Expense	$0	**Yes**
5520	Miscellaneous Sales Expense	$0	**Yes**
5605	Executive Salaries and Expenses	$0	**Yes**

5610	Management Salaries and Expenses	$0	Yes
5615	General Administrative Salaries and Expenses	$0	Yes
5620	Office Supplies and Expenses	$0	Yes
5625	Administrative Expense Transferred Credit	$0	Yes
5630	Outside Services Employed	$0	Yes
5635	Property Insurance	$0	Yes
5640	Injuries and Damages	$0	Yes
5645	Employee Pensions and Benefits	$0	Yes
5650	Franchise Requirements	$0	Yes
5655	Regulatory Expenses	$0	Yes
5660	General Advertising Expenses	$0	Yes
5665	Miscellaneous General Expenses	$0	Yes
5670	Rent	$0	Yes
5675	Maintenance of General Plant	$0	Yes
5680	Electrical Safety Authority Fees	$0	Yes
5682	IFRS Placeholder Expense Account	$0	Yes
5705	Amortization Expense - Property, Plant, and Equipment	$0	Yes
5710	Amortization of Limited Term Electric Plant	$0	Yes
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes
6105	Taxes Other Than Income Taxes	$0	Yes
6205	Donations	$0	Yes
6210	Life Insurance	$0	Yes
6215	Penalties	$0	Yes
6225	Other Deductions	$0	Yes
	Total Expenses		
	Depreciation Expense		

Total Net Fixed Assets Excluding Gen Plant	**$97,632,009**	**Allocated**
Approved Total PILs	**$496,909**	**$0**
Approved Total Return on Debt	**$2,306,055**	**$0**
Approved Total Return on Equity	**$2,779,887**	**$0**

Total

ost Allocation Model

-Staff's Updated Cost Allocation Study

1	2	3	7	8
Residential	GS <50	GS>50-Regular	Street Light	Sentinel

$0	$0	$0	$0	$0

$0	$0	$0	$0	$0
$0	$0	$0	$0	$0

Residential	GS <50	GS>50-Regular	Street Light	Sentinel
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**

9	10
netered Scattered L	mbedded Distributor

$0	$0

$0	$0
$0	$0

etered Scattered I	mbedded Distributor
$0	$0
$0	$0
$0	$0
$0	**$0**

Sheet O1 Revenue to Cost Summary Worksheet - 1-Staff-2 Updated Cost Allocation Study

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9	10
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
crev	Distribution Revenue at Existing Rates	$15,096,208	$8,617,961	$1,436,711	$4,507,578	$144,395	$32,766	$73,750	$283,047
mi	Miscellaneous Revenue (mi)	$1,161,146	$825,061	$119,260	$183,174	$7,534	$6,819	$6,623	$12,674
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$16,257,354	$9,443,022	$1,555,971	$4,690,752	$151,930	$39,586	$80,373	$295,721
	Factor required to recover deficiency (1 + D)	1.1018							
	Distribution Revenue at Status Quo Rates	$16,633,314	$9,495,448	$1,582,998	$4,966,543	$159,098	$36,103	$81,259	$311,867
	Miscellaneous Revenue (mi)	$1,161,146	$825,061	$119,260	$183,174	$7,534	$6,819	$6,623	$12,674
	Total Revenue at Status Quo Rates	$17,794,460	$10,320,509	$1,702,258	$5,149,717	$166,632	$42,922	$87,882	$324,541
	Expenses								
di	Distribution Costs (di)	$3,011,210	$1,722,263	$287,282	$863,798	$32,994	$15,167	$11,292	$78,416
cu	Customer Related Costs (cu)	$3,461,601	$2,623,047	$449,415	$350,780	$137	$14,786	$23,383	$53
ad	General and Administration (ad)	$2,743,214	$1,818,479	$312,186	$535,201	$15,038	$12,765	$14,430	$35,114
dep	Depreciation and Amortization (dep)	$2,995,584	$1,635,386	$391,348	$863,984	$27,854	$12,634	$9,311	$55,066
INPUT	PILs (INPUT)	$496,909	$263,311	$56,468	$155,477	$5,540	$2,500	$1,851	$11,763
INT	Interest	$2,306,055	$1,221,973	$262,057	$721,537	$25,709	$11,603	$8,589	$54,587
	Total Expenses	$15,014,573	$9,284,459	$1,758,757	$3,490,776	$107,273	$69,455	$68,855	$234,999
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,779,887	$1,473,055	$315,903	$869,793	$30,991	$13,987	$10,354	$65,804
	Revenue Requirement (includes NI)	$17,794,460	$10,757,514	$2,074,659	$4,360,569	$138,264	$83,442	$79,209	$300,802
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$97,632,009	$51,873,413	$11,010,403	$30,502,082	$1,124,381	$510,138	$375,984	$2,235,607
gp	General Plant - Gross	$4,937,492	$2,620,627	$561,055	$1,541,392	$55,284	$24,988	$18,476	$115,671
accum dep	Accumulated Depreciation	-$34,176,343	-$18,180,213	-$3,799,945	-$10,703,414	-$413,134	-$188,547	-$138,267	-$752,823
co	Capital Contribution	-$4,558,844	-$2,486,477	-$517,481	-$1,368,464	-$54,784	-$25,331	-$18,410	-$87,896
	Total Net Plant	$63,834,314	$33,827,349	$7,254,032	$19,971,596	$711,747	$321,248	$237,782	$1,510,559
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$95,066,625	$28,754,754	$9,981,605	$55,331,425	$798,230	$46,870	$153,741	$0
	OM&A Expenses	$9,216,025	$6,163,789	$1,048,883	$1,749,778	$48,170	$42,717	$49,105	$113,583
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$104,282,650*	*$34,918,543*	*$11,030,488*	*$57,081,203*	*$846,400*	*$89,587*	*$202,846*	*$113,583*
	Working Capital	$13,556,745	$4,539,411	$1,433,963	$7,420,556	$110,032	$11,646	$26,370	$14,766
	Total Rate Base	$77,391,058	$38,366,760	$8,687,996	$27,392,152	$821,779	$332,894	$264,152	$1,525,325
		Rate Base Input equals Output							
	Equity Component of Rate Base	$30,956,423	$15,346,704	$3,475,198	$10,956,861	$328,712	$133,158	$105,661	$610,130
	Net Income on Allocated Assets	$2,751,067	$1,036,050	-$56,499	$1,658,941	$59,360	-$26,533	$19,027	$60,722
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,751,067	$1,036,050	-$56,499	$1,658,941	$59,360	-$26,533	$19,027	$60,722
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	95.94%	82.05%	118.10%	120.52%	51.44%	110.95%	107.89%
	EXISTING REVENUE MINUS ALLOCATED COSTS	-$1,537,106	-$1,314,492	-$518,689	$330,183	$13,666	-$43,857	$1,164	-$5,081
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	-$0	-$437,005	-$372,402	$789,147	$28,368	-$40,520	$8,673	$23,739
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.89%	6.75%	-1.63%	15.14%	18.06%	-19.93%	18.01%	9.95%

2013 Cost Allocation Model

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 1-Staff-2 Updated Cost Allocation Study

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9	10
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Customer Unit Cost per month - Avoided Cost	$5.70	$17.92	$95.70	-$0.02	$1.18	$2.82	-$16.26
Customer Unit Cost per month - Directly Related	$7.49	$22.36	$118.47	-$0.01	$1.71	$4.04	-$15.83
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.85	$35.60	$157.63	$6.92	$10.87	$11.91	-$11.78
Existing Approved Fixed Charge	$11.46	$24.81	$293.71	$0.65	$2.32	$12.06	$293.71

2013 Cos

Sheet O2.1 Line Transformer Worksheet -

Line Transformers Demand Unit Cost for PLCC
Adjustment to Customer Related Cost
Allocation by rate classification

Description	Total
Depreciation on Acct 1850 Line Transformers	$256,009
Depreciation on General Plant Assigned to Line Transformers	$18,982
Acct 5035 - Overhead Distribution Transformers- Operation	$3,092
Acct 5055 - Underground Distribution Transformers - Operation	$0
Acct 5160 - Maintenance of Line Transformers	$115,718
Allocation of General Expenses	$145,954
Admin and General Assigned to Line Transformers	$51,581
PILs on Line Transformers	$49,859
Debt Return on Line Transformers	$231,386
Equity Return on Line Transformers	$278,929
Total	**$1,151,511**
Line Tranformer NCP	565,100
PLCC Amount	63,915
Adjustment to Customer Related Cost for PLCC	**$128,835**
General Plant - Gross Assets	$4,937,492
General Plant - Accumulated Depreciation	-$2,960,774
General Plant - Net Fixed Assets	$1,976,718
General Plant - Depreciation	$189,285
Total Net Fixed Assets Excluding General Plant	**$61,857,596**
Total Administration and General Expense	$2,743,214
Total O&M	**$6,428,356**

<u>Line Transformer Rate Base</u>	
Acct 1850 - Line Transformers - Gross Assets	$10,580,863
Line Transformers - Accumulated Depreciation	-$4,374,175
Line Transformers - Net Fixed Assets	$6,206,688
General Plant Assigned to Line Transformers - NFA	$198,225
Line Transformer Net Fixed Assets Including General Plant	$6,404,913
<u>General Expenses</u>	
Acct 5005 - Operation Supervision and Engineering	$163,950
Acct 5010 - Load Dispatching	$68,847
Acct 5085 - Miscellaneous Distribution Expense	$197,525
Acct 5105 - Maintenance Supervision and Engineering	$299,759
Total	$730,082
Acct 1850 - Line Transformers - Gross Assets	$10,580,863
Acct 1815 - 1855	$52,926,939

t Allocation Model

1-Staff-2 Updated Cost Allocation Study

1	2	3	4	5
Residential	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**
$84,316	$35,599	$132,591	$0	$0
$6,265	$2,641	$9,814	$0	$0
$1,018	$430	$1,602	$0	$0
$0	$0	$0	$0	$0
$38,111	$16,091	$59,932	$0	$0
$48,070	$20,296	$75,592	$0	$0
$16,489	$7,050	$27,302	$0	$0
$16,421	$6,933	$25,823	$0	$0
$76,206	$32,175	$119,838	$0	$0
$91,865	$38,787	$144,462	$0	$0
$378,762	**$160,002**	**$596,957**	**$0**	**$0**
186,114	78,580	292,674	0	0
56,582	4,411	574	0	0
$115,150	**$8,982**	**$1,171**	**$0**	**$0**
$2,620,627	$561,055	$1,541,392	$0	$0
-$1,571,463	-$336,437	-$924,298	$0	$0
$1,049,164	$224,618	$617,094	$0	$0
$100,465	$21,509	$59,091	$0	$0
$32,778,185	**$7,029,415**	**$19,354,502**	**$0**	**$0**
$1,818,479	$312,186	$535,201	$0	$0
$4,315,466	**$731,637**	**$1,206,236**	**$0**	**$0**

$3,484,785	$1,471,323	$5,480,002	$0	$0
-$1,440,625	-$608,251	-$2,265,457	$0	$0
$2,044,160	$863,072	$3,214,545	$0	$0
$65,429	$27,579	$102,492	$0	$0
$2,109,589	$890,650	$3,317,037	$0	$0
$49,453	$20,463	$85,521	$0	$0
$20,767	$8,593	$35,913	$0	$0
$59,581	$24,654	$103,035	$0	$0
$90,418	$37,414	$156,363	$0	$0
$220,219	$91,124	$380,832	$0	$0
$3,484,785	$1,471,323	$5,480,002	$0	$0
$15,964,682	$6,606,014	$27,608,256	$0	$0

6	7	8	9	10
Large Use >5MW	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
$0	$3,389	$0	$113	$0
$0	$253	$0	$8	$0
$0	$41	$0	$1	$0
$0	$0	$0	$0	$0
$0	$1,532	$0	$51	$0
$0	$1,932	$0	$65	$0
$0	$719	$0	$22	$0
$0	$660	$0	$22	$0
$0	$3,063	$0	$102	$0
$0	$3,692	$0	$124	$0
$0	**$15,281**	**$0**	**$509**	**$0**
0	7,481	0	250	0
0	1,032	616	700	0
$0	**$2,109**	**$0**	**$1,423**	**$0**
$0	$55,284	$24,988	$18,476	$115,671
$0	-$33,151	-$14,984	-$11,079	-$69,362
$0	$22,133	$10,004	$7,397	$46,309
$0	$2,119	$958	$708	$4,434
$0	**$689,614**	**$311,244**	**$230,385**	**$1,464,251**
$0	$15,038	$12,765	$14,430	$35,114
$0	**$32,904**	**$29,747**	**$34,437**	**$77,930**

$0	$140,067	$0	$4,686	$0
$0	-$57,904	$0	-$1,937	$0
$0	$82,163	$0	$2,749	$0
$0	$2,637	$0	$88	$0
$0	$84,800	$0	$2,837	$0
$0	$1,863	$3	$75	$6,572
$0	$782	$1	$31	$2,760
$0	$2,245	$3	$90	$7,918
$0	$3,407	$5	$136	$12,016
$0	$8,297	$11	$332	$29,266
$0	$140,067	$0	$4,686	$0
$0	$601,481	$829	$24,060	$2,121,618

11	12	13	14	15
Back-up/Standby Power	**Rate Class 1**	**Rate class 2**	**Rate class 3**	**Rate class 4**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
0	0	0	0	0
0	0	0	0	0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**

$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0

16	17	18	19	20
Rate class 5	**Rate class 6**	**Rate class 7**	**Rate class 8**	**Rate class 9**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
0	0	0	0	0
0	0	0	0	0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**

$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0

Sheet O2.2 Primary Cost PLCC Adjustment V

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$174,435
Depreciation on Acct 1835-4 Primary Overhead Conductors	$97,162
Depreciation on Acct 1840-4 Primary Underground Conduit	$24,781
Depreciation on Acct 1845-4 Primary Underground Conductors	$189,419
Depreciation on General Plant Assigned to Primary C&P	$40,162
Primary C&P Operations and Maintenance	$344,888
Allocation of General Expenses	$294,555
Admin and General Assigned to Primary C&P	$150,559
PILs on Primary C&P	$105,593
Debt Return on Primary C&P	$490,034
Equity Return on Primary C&P	$590,723
Total	**$2,502,310**
Primary NCP	670,485
PLCC Amount	64,029
Adjustment to Customer Related Cost for PLCC	**$235,081**
General Plant - Gross Assets	$4,937,492
General Plant - Accumulated Depreciation	-$2,960,774
General Plant - Net Fixed Assets	$1,976,718
General Plant - Depreciation	$189,285
Total Net Fixed Assets Excluding General Plant	**$61,857,596**
Total Administration and General Expense	**$2,743,214**

Total O&M	**$6,428,356**
<u>Primary Conductors and Poles Gross Assets</u>	
Acct 1830-4 Primary Poles, Towers & Fixtures	$8,400,367
Acct 1835-4 Primary Overhead Conductors	$5,550,671
Acct 1840-4 Primary Underground Conduit	$1,581,868
Acct 1845-4 Primary Underground Conductors	$5,820,699
Subtotal	*$21,353,604*
<u>Primary Conductors and Poles Accumulated Depreciation</u>	
Acct 1830-4 Primary Poles, Towers & Fixtures	-$3,595,006
Acct 1835-4 Primary Overhead Conductors	-$2,135,635
Acct 1840-4 Primary Underground Conduit	-$683,568
Acct 1845-4 Primary Underground Conductors	-$1,794,723
Subtotal	***-$8,208,932***
Primary Conductor & Pools - Net Fixed Assets	$13,144,673
General Plant Assigned to Primary C&P - NFA	$419,415
Primary C&P Net Fixed Assets Including General Plant	$13,564,088
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0
Acct 1835-3 Bulk Overhead Conductors	$0
Acct 1840-3 Bulk Underground Conduit	$0
Acct 1845-3 Bulk Underground Conductors	$0
Subtotal	***$0***
Acct 1830-5 Secondary Poles, Towers & Fixtures	$1,843,983
Acct 1835-5 Secondary Overhead Conductors	$2,267,175
Acct 1840-5 Secondary Underground Conduit	$6,743,752
Acct 1845-5 Secondary Underground Conductors	$5,592,436
Subtotal	***$16,447,347***
<u>Operations and Maintenance</u>	
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$1,177
Acct 5025 Overhead Distribution Lines & Feeders - Other	$7,651
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$7,194
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$15,242
Acct 5120 Maintenance of Poles, Towers & Fixtures	$45,248
Acct 5125 Maintenance of Overhead Conductors & Devices	$145,213
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$299,721
Acct 5145 Maintenance of Underground Conduit	$34,141
Acct 5150 Maintenance of Underground Conductors & Devices	$49,387
Total	**$604,975**
<u>General Expenses</u>	
Acct 5005 - Operation Supervision and Engineering	$163,950
Acct 5010 - Load Dispatching	$68,847

Acct 5085 - Miscellaneous Distribution Expense	$197,525
Acct 5105 - Maintenance Supervision and Engineering	$299,759
Total	**$730,082**
Primary Conductors and Poles Gross Assets	$21,353,604
Acct 1815 - 1855	$52,926,939

Allocation Model

Vorksheet - 1-Staff-2 Updated Cost Allocation Study

1	2	3	4	5
Residential	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**
$48,420	$20,495	$89,089	$0	$0
$26,970	$11,416	$49,623	$0	$0
$6,879	$2,912	$12,656	$0	$0
$52,579	$22,256	$96,741	$0	$0
$11,183	$4,726	$20,497	$0	$0
$93,382	$39,527	$172,994	$0	$0
$81,763	$34,609	$150,437	$0	$0
$39,350	$16,866	$76,757	$0	$0
$29,311	$12,407	$53,929	$0	$0
$136,025	$57,577	$250,274	$0	$0
$163,974	$69,408	$301,698	$0	$0
$689,836	**$292,199**	**$1,274,696**	**$0**	**$0**
186,114	78,780	342,435	0	0
56,582	4,423	672	0	0
$209,722	**$16,404**	**$2,500**	**$0**	**$0**
$2,620,627	$561,055	$1,541,392	$0	$0
-$1,571,463	-$336,437	-$924,298	$0	$0
$1,049,164	$224,618	$617,094	$0	$0
$100,465	$21,509	$59,091	$0	$0
$32,778,185	**$7,029,415**	**$19,354,502**	**$0**	**$0**
$1,818,479	**$312,186**	**$535,201**	**$0**	**$0**

$4,315,466	**$731,637**	**$1,206,236**	**$0**	**$0**
$2,331,788	$987,012	$4,290,296	$0	$0
$1,540,764	$652,183	$2,834,879	$0	$0
$439,098	$185,864	$807,903	$0	$0
$1,615,719	$683,910	$2,972,789	$0	$0
$5,927,369	*$2,508,968*	*$10,905,867*	*$0*	*$0*
-$997,908	-$422,400	-$1,836,068	$0	$0
-$592,813	-$250,929	-$1,090,727	$0	$0
-$189,746	-$80,317	-$349,117	$0	$0
-$498,182	-$210,873	-$916,614	$0	$0
-$2,278,649	***-$964,519***	***-$4,192,525***	***$0***	***$0***
$3,648,720	$1,544,450	$6,713,342	$0	$0
$116,788	$49,351	$214,046	$0	$0
$3,765,508	$1,593,801	$6,927,389	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***
$573,185	$242,621	$1,004,367	$0	$0
$704,731	$298,302	$1,234,869	$0	$0
$2,096,234	$887,305	$3,673,138	$0	$0
$1,738,358	$735,821	$3,046,048	$0	$0
$5,112,508	***$2,164,050***	***$8,958,423***	***$0***	***$0***
$336	$142	$610	$0	$0
$2,182	$924	$3,967	$0	$0
$0	$0	$0	$0	$0
$2,146	$909	$3,827	$0	$0
$0	$0	$0	$0	$0
$4,346	$1,840	$7,902	$0	$0
$12,831	$5,431	$23,386	$0	$0
$41,709	$17,655	$75,594	$0	$0
$85,466	$36,177	$155,391	$0	$0
$10,397	$4,401	$18,376	$0	$0
$14,514	$6,143	$26,045	$0	$0
$173,927	**$73,621**	**$315,098**	**$0**	**$0**
$49,453	$20,463	$85,521	$0	$0
$20,767	$8,593	$35,913	$0	$0

$59,581	$24,654	$103,035	$0	$0
$90,418	$37,414	$156,363	$0	$0
$220,219	**$91,124**	**$380,832**	**$0**	**$0**
$5,927,369	$2,508,968	$10,905,867	$0	$0
$15,964,682	$6,606,014	$27,608,256	$0	$0

6	7	8	9	10
Large Use >5MW	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
$0	$1,946	$0	$65	$14,420
$0	$1,084	$0	$36	$8,032
$0	$276	$0	$9	$2,048
$0	$2,113	$0	$71	$15,658
$0	$451	$0	$15	$3,291
$0	$3,753	$0	$126	$35,105
$0	$3,286	$0	$110	$24,349
$0	$1,715	$0	$53	$15,818
$0	$1,178	$0	$39	$8,729
$0	$5,467	$0	$183	$40,508
$0	$6,591	$0	$220	$48,832
$0	**$27,862**	**$0**	**$927**	**$216,790**
0	7,481	0	250	55,425
0	1,032	616	700	5
$0	**$3,845**	**$0**	**$2,592**	**$19**
$0	$55,284	$24,988	$18,476	$115,671
$0	-$33,151	-$14,984	-$11,079	-$69,362
$0	$22,133	$10,004	$7,397	$46,309
$0	$2,119	$958	$708	$4,434
$0	**$689,614**	**$311,244**	**$230,385**	**$1,464,251**
$0	**$15,038**	**$12,765**	**$14,430**	**$35,114**

$0	**$32,904**	**$29,747**	**$34,437**	**$77,930**
$0	$93,724	$0	$3,136	$694,412
$0	$61,929	$0	$2,072	$458,843
$0	$17,649	$0	$590	$130,764
$0	$64,942	$0	$2,173	$481,165
$0	*$238,244*	*$0*	*$7,971*	*$1,765,185*
$0	-$40,110	$0	-$1,342	-$297,179
$0	-$23,827	$0	-$797	-$176,541
$0	-$7,627	$0	-$255	-$56,507
$0	-$20,024	$0	-$670	-$148,360
$0	***-$91,588***	***$0***	***-$3,064***	***-$678,587***
$0	$146,656	$0	$4,907	$1,086,598
$0	$4,707	$0	$158	$34,365
$0	$151,363	$0	$5,064	$1,120,963
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***
$0	$23,039	$0	$771	$0
$0	$28,326	$0	$948	$0
$0	$84,256	$0	$2,819	$0
$0	$69,871	$0	$2,338	$0
$0	***$205,491***	***$0***	***$6,875***	***$0***
$0	$13	$0	$0	$75
$0	$88	$0	$3	$489
$0	$0	$0	$0	$0
$0	$86	$0	$3	$223
$0	$0	$0	$0	$0
$0	$175	$0	$6	$973
$0	$516	$0	$17	$3,067
$0	$1,676	$0	$56	$8,523
$0	$3,435	$0	$115	$19,137
$0	$418	$0	$14	$536
$0	$583	$0	$20	$2,082
$0	**$6,991**	**$0**	**$234**	**$35,105**
$0	$1,863	$3	$75	$6,572
$0	$782	$1	$31	$2,760

	$0	$2,245	$3	$90	$7,918
	$0	$3,407	$5	$136	$12,016
	$0	**$8,297**	**$11**	**$332**	**$29,266**
	$0	$238,244	$0	$7,971	$1,765,185
	$0	$601,481	$829	$24,060	$2,121,618

11	12	13	14	15
Back-up/Standby Power	**Rate Class 1**	**Rate class 2**	**Rate class 3**	**Rate class 4**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
0	0	0	0	0
0	0	0	0	0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$0	**$0**	**$0**	**$0**	**$0**

$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
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$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	*$0*	*$0*	*$0*	*$0*
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
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$0	***$0***	***$0***	***$0***	***$0***
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$0	***$0***	***$0***	***$0***	***$0***
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$0	***$0***	***$0***	***$0***	***$0***
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$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0

	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0
	$0	**$0**	**$0**	**$0**	**$0**
	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0

16	17	18	19	20
Rate class 5	**Rate class 6**	**Rate class 7**	**Rate class 8**	**Rate class 9**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
0	0	0	0	0
0	0	0	0	0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$0	**$0**	**$0**	**$0**	**$0**

$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	*$0*	*$0*	*$0*	*$0*
$0	$0	$0	$0	$0
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$0	***$0***	***$0***	***$0***	***$0***
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$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***
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$0	***$0***	***$0***	***$0***	***$0***
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$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0

	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0
	$0	**$0**	**$0**	**$0**	**$0**
	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0

Sheet O2.3 Secondary Cost PLCC Adjustmen

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$38,291
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$66,143
Depreciation on Acct 1840-5 Secondary Underground Conduit	$176,073
Depreciation on Acct 1845-5 Secondary Underground Conductors	$303,317
Depreciation on General Plant Assigned to Secondary C&P	$31,030
Secondary C&P Operations and Maintenance	$260,087
Allocation of General Expenses	$226,877
Admin and General Assigned to Primary C&P	$113,063
PILs on Secondary C&P	$81,515
Debt Return on Secondary C&P	$378,296
Equity Return on Secondary C&P	$456,025
Total	**$2,130,717**
Secondary NCP	598,745
PLCC Amount	64,024
Adjustment to Customer Related Cost for PLCC	**$268,315**
General Plant - Gross Assets	$4,937,492
General Plant - Accumulated Depreciation	-$2,960,774
General Plant - Net Fixed Assets	$1,976,718
General Plant - Depreciation	$189,285
Total Net Fixed Assets Excluding General Plant	$61,857,596
Total Administration and General Expense	$2,743,214

Total O&M	$6,428,356
Secondary Conductors and Poles Gross Plant	
Acct 1830-5 Secondary Poles, Towers & Fixtures	$1,843,983
Acct 1835-5 Secondary Overhead Conductors	$2,267,175
Acct 1840-5 Secondary Underground Conduit	$6,743,752
Acct 1845-5 Secondary Underground Conductors	$5,592,436
Subtotal	***$16,447,347***
Secondary Conductors and Poles Accumulated Depreciation	
Acct 1830-5 Secondary Poles, Towers & Fixtures	-$789,148
Acct 1835-5 Secondary Overhead Conductors	-$872,302
Acct 1840-5 Secondary Underground Conduit	-$2,914,158
Acct 1845-5 Secondary Underground Conductors	-$1,724,341
Subtotal	***-$6,299,948***
Secondary Conductor & Pools - Net Fixed Assets	$10,147,398
General Plant Assigned to Secondary C&P - NFA	$324,050
Secondary C&P Net Fixed Assets Including General Plant	$10,471,449
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0
Acct 1835-3 Bulk Overhead Conductors	$0
Acct 1840-3 Bulk Underground Conduit	$0
Acct 1845-3 Bulk Underground Conductors	$0
Subtotal	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$8,400,367
Acct 1835-4 Primary Overhead Conductors	$5,550,671
Acct 1840-4 Primary Underground Conduit	$1,581,868
Acct 1845-4 Primary Underground Conductors	$5,820,699
Subtotal	***$21,353,604***
Operations and Maintenance	
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$1,177
Acct 5025 Overhead Distribution Lines & Feeders - Other	$7,651
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$7,194
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$15,242
Acct 5120 Maintenance of Poles, Towers & Fixtures	$45,248
Acct 5125 Maintenance of Overhead Conductors & Devices	$145,213
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$299,721
Acct 5145 Maintenance of Underground Conduit	$34,141
Acct 5150 Maintenance of Underground Conductors & Devices	$49,387
Total	**$604,975**
General Expenses	
Acct 5005 - Operation Supervision and Engineering	$163,950
Acct 5010 - Load Dispatching	$68,847
Acct 5085 - Miscellaneous Distribution Expense	$197,525
Acct 5105 - Maintenance Supervision and Engineering	$299,759

Total	**$730,082**
Secondary Conductors and Poles Gross Assets	$16,447,347
Acct 1815 - 1855	$52,926,939

Allocation Model

nt Worksheet - 1-Staff-2 Updated Cost Allocation Stu

1	2	3	4	5
Residential	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**
$11,902	$5,038	$20,856	$0	$0
$35,584	$7,039	$21,879	$0	$0
$94,725	$18,737	$58,241	$0	$0
$163,181	$32,278	$100,330	$0	$0
$9,668	$4,085	$16,875	$0	$0
$80,545	$34,093	$142,103	$0	$0
$70,523	$29,851	$123,574	$0	$0
$33,940	$14,547	$63,050	$0	$0
$25,338	$10,725	$44,399	$0	$0
$117,590	$49,774	$206,047	$0	$0
$141,751	$60,001	$248,384	$0	$0
$784,747	**$266,170**	**$1,045,739**	**$0**	**$0**
186,114	78,780	326,120	0	0
56,582	4,423	672	0	0
$238,576	**$14,942**	**$2,154**	**$0**	**$0**
$2,620,627	$561,055	$1,541,392	$0	$0
-$1,571,463	-$336,437	-$924,298	$0	$0
$1,049,164	$224,618	$617,094	$0	$0
$100,465	$21,509	$59,091	$0	$0
$32,778,185	$7,029,415	$19,354,502	$0	$0
$1,818,479	$312,186	$535,201	$0	$0

$4,315,466	$731,637	$1,206,236	$0	$0
$573,185	$242,621	$1,004,367	$0	$0
$704,731	$298,302	$1,234,869	$0	$0
$2,096,234	$887,305	$3,673,138	$0	$0
$1,738,358	$735,821	$3,046,048	$0	$0
$5,112,508	***$2,164,050***	***$8,958,423***	***$0***	***$0***
-$245,299	-$103,832	-$429,827	$0	$0
-$271,147	-$114,773	-$475,119	$0	$0
-$905,839	-$383,429	-$1,587,262	$0	$0
-$535,996	-$226,879	-$939,202	$0	$0
-$1,958,282	***-$828,912***	***-$3,431,410***	***$0***	***$0***
$3,154,227	$1,335,138	$5,527,012	$0	$0
$100,960	$42,663	$176,222	$0	$0
$3,255,187	$1,377,801	$5,703,234	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***
$2,331,788	$987,012	$4,290,296	$0	$0
$1,540,764	$652,183	$2,834,879	$0	$0
$439,098	$185,864	$807,903	$0	$0
$1,615,719	$683,910	$2,972,789	$0	$0
$5,927,369	***$2,508,968***	***$10,905,867***	***$0***	***$0***
$336	$142	$610	$0	$0
$2,182	$924	$3,967	$0	$0
$0	$0	$0	$0	$0
$2,146	$909	$3,827	$0	$0
$0	$0	$0	$0	$0
$4,346	$1,840	$7,902	$0	$0
$12,831	$5,431	$23,386	$0	$0
$41,709	$17,655	$75,594	$0	$0
$85,466	$36,177	$155,391	$0	$0
$10,397	$4,401	$18,376	$0	$0
$14,514	$6,143	$26,045	$0	$0
$173,927	**$73,621**	**$315,098**	**$0**	**$0**
$49,453	$20,463	$85,521	$0	$0
$20,767	$8,593	$35,913	$0	$0
$59,581	$24,654	$103,035	$0	$0
$90,418	$37,414	$156,363	$0	$0

$220,219	**$91,124**	**$380,832**	**$0**	**$0**
$5,112,508	$2,164,050	$8,958,423	$0	$0
$15,964,682	$6,606,014	$27,608,256	$0	$0

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6	7	8	9	10
Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
$0	$478	$0	$16	$0
$0	$920	$418	$304	$0
$0	$2,449	$1,111	$809	$0
$0	$4,219	$1,915	$1,394	$0
$0	$390	$0	$13	$0
$0	$3,237	$0	$108	$0
$0	$2,835	$0	$95	$0
$0	$1,480	$0	$45	$0
$0	$1,018	$0	$34	$0
$0	$4,726	$0	$158	$0
$0	$5,698	$0	$191	$0
$0	**$27,450**	**$3,444**	**$3,168**	**$0**
0	7,481	0	250	0
0	1,032	616	700	0
$0	**$3,788**	**$0**	**$8,855**	**$0**
$0	$55,284	$24,988	$18,476	$115,671
$0	-$33,151	-$14,984	-$11,079	-$69,362
$0	$22,133	$10,004	$7,397	$46,309
$0	$2,119	$958	$708	$4,434
$0	$689,614	$311,244	$230,385	$1,464,251
$0	$15,038	$12,765	$14,430	$35,114

$0	$32,904	$29,747	$34,437	$77,930
$0	$23,039	$0	$771	$0
$0	$28,326	$0	$948	$0
$0	$84,256	$0	$2,819	$0
$0	$69,871	$0	$2,338	$0
$0	***$205,491***	***$0***	***$6,875***	***$0***
$0	-$9,860	$0	-$330	$0
$0	-$10,898	$0	-$365	$0
$0	-$36,409	$0	-$1,218	$0
$0	-$21,544	$0	-$721	$0
$0	***-$78,711***	***$0***	***-$2,633***	***$0***
$0	$126,781	$0	$4,242	$0
$0	$4,069	$0	$136	$0
$0	$130,849	$0	$4,378	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***
$0	$93,724	$0	$3,136	$694,412
$0	$61,929	$0	$2,072	$458,843
$0	$17,649	$0	$590	$130,764
$0	$64,942	$0	$2,173	$481,165
$0	***$238,244***	***$0***	***$7,971***	***$1,765,185***
$0	$13	$0	$0	$75
$0	$88	$0	$3	$489
$0	$0	$0	$0	$0
$0	$86	$0	$3	$223
$0	$0	$0	$0	$0
$0	$175	$0	$6	$973
$0	$516	$0	$17	$3,067
$0	$1,676	$0	$56	$8,523
$0	$3,435	$0	$115	$19,137
$0	$418	$0	$14	$536
$0	$583	$0	$20	$2,082
$0	**$6,991**	**$0**	**$234**	**$35,105**
$0	$1,863	$3	$75	$6,572
$0	$782	$1	$31	$2,760
$0	$2,245	$3	$90	$7,918
$0	$3,407	$5	$136	$12,016

	$0	**$8,297**	**$11**	**$332**	**$29,266**
	$0	$205,491	$0	$6,875	$0
	$0	$601,481	$829	$24,060	$2,121,618

11	12	13	14	15
Back-up/Standby Power	**Rate Class 1**	**Rate class 2**	**Rate class 3**	**Rate class 4**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
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$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
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$0	**$0**	**$0**	**$0**	**$0**
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$0	***$0***	***$0***	***$0***	***$0***
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$0	***$0***	***$0***	***$0***	***$0***
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$0	***$0***	***$0***	***$0***	***$0***
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$0	**$0**	**$0**	**$0**	**$0**
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$0	$0	$0	$0	$0

	$0	**$0**	**$0**	**$0**	**$0**
	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0

16	17	18	19	20
Rate class 5	**Rate class 6**	**Rate class 7**	**Rate class 8**	**Rate class 9**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
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$0	**$0**	**$0**	**$0**	**$0**
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$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0

$0	**$0**	**$0**	**$0**	**$0**
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0

Sheet O3.1 Line Transformers Unit Cost

ALLOCATION BY RATE CLASSIFICATION

Description	Total
Depreciation on Acct 1850 Line Transformers	$426,682
Depreciation on General Plant Assigned to Line Transformers	$31,664
Acct 5035 - Overhead Distribution Transformers- Operation	$5,154
Acct 5055 - Underground Distribution Transformers - Operation	$0
Acct 5160 - Maintenance of Line Transformers	$192,863
Allocation of General Expenses	$247,278
Admin and General Assigned to Line Transformers	$85,056
PILs on Line Transformers	$83,098
Debt Return on Line Transformers	$385,643
Equity Return on Line Transformers	$464,882
Total	**Error - Please Rev**
Billed kW without Line Transformer Allowance	
Billed kWh without Line Transformer Allowance	
Line Transformation Unit Cost ($/kW)	
Line Transformation Unit Cost ($/kWh)	
General Plant - Gross Assets	$4,937,492
General Plant - Accumulated Depreciation	-$2,960,774
General Plant - Net Fixed Assets	$1,976,718
General Plant - Depreciation	$189,285
Total Net Fixed Assets Excluding General Plant	$61,857,596
Total Administration and General Expense	$2,743,214
Total O&M	$6,428,356

<u>Line Transformer Rate Base</u>	
Acct 1850 - Line Transformers - Gross Assets	$17,634,772
Line Transformers - Accumulated Depreciation	-$7,290,292
Line Transformers - Net Fixed Assets	$10,344,480
General Plant Assigned to Line Transformers - NFA	$330,666
Line Transformer Net Fixed Assets Including General Plant	$10,675,147
<u>General Expenses</u>	
Acct 5005 - Operation Supervision and Engineering	$273,250
Acct 5010 - Load Dispatching	$114,745
Acct 5085 - Miscellaneous Distribution Expense	$329,209
Acct 5105 - Maintenance Supervision and Engineering	$499,599
Total	**$1,216,803**
Acct 1850 - Line Transformers - Gross Assets	$17,634,772
Acct 1815 - 1855	$86,837,480

st Allocation Model

Worksheet - 1-Staff-2 Updated Cost Allocation Study

1	2	3	7	8
Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**
$234,467	$47,306	$134,115	$6,128	$2,697
$17,423	$3,509	$9,927	$457	$201
$2,832	$571	$1,620	$74	$33
$0	$0	$0	$0	$0
$105,981	$21,382	$60,621	$2,770	$1,219
$137,203	$27,251	$76,500	$3,559	$1,600
$45,852	$9,368	$27,616	$1,300	$537
$45,664	$9,213	$26,120	$1,194	$525
$211,915	$42,756	$121,215	$5,539	$2,437
$255,458	$51,541	$146,122	$6,677	$2,938
$1,056,795	**$212,898**	**$603,855**	**$27,697**	**$12,187**
0	-210	594,341	23,455	1,356
272,082,836	94,447,805	523,567,859	7,553,004	443,490
$0.0000	**-$1,011.9723**	**$1.0160**	**$1.1808**	**$8.9860**
$0.0039	**$0.0023**	**$0.0012**	**$0.0037**	**$0.0275**
$2,620,627	$561,055	$1,541,392	$55,284	$24,988
-$1,571,463	-$336,437	-$924,298	-$33,151	-$14,984
$1,049,164	$224,618	$617,094	$22,133	$10,004
$100,465	$21,509	$59,091	$2,119	$958
$32,778,185	$7,029,415	$19,354,502	$689,614	$311,244
$1,818,479	$312,186	$535,201	$15,038	$12,765
$4,315,466	$731,637	$1,206,236	$32,904	$29,747

$9,690,517	$1,955,146	$5,542,961	$253,282	$111,453
-$4,006,102	-$808,266	-$2,291,484	-$104,708	-$46,075
$5,684,415	$1,146,880	$3,251,477	$148,574	$65,378
$181,947	$36,647	$103,669	$4,768	$2,101
$5,866,362	$1,183,528	$3,355,146	$153,342	$67,479
$145,780	$27,855	$86,661	$3,531	$1,643
$61,217	$11,697	$36,391	$1,483	$690
$175,635	$33,560	$104,408	$4,254	$1,980
$266,538	$50,930	$158,447	$6,456	$3,005
$649,170	**$124,042**	**$385,907**	**$15,723**	**$7,318**
$9,690,517	$1,955,146	$5,542,961	$253,282	$111,453
$45,850,294	$8,899,430	$27,961,800	$1,118,864	$509,873

9	10
Unmetered Scattered Load	**Embedded Distributor**
$1,970	$0
$147	$0
$24	$0
$0	$0
$890	$0
$1,166	$0
$383	$0
$384	$0
$1,780	$0
$2,146	$0
$8,890	**$0**
0	155,806
1,454,727	0
$0.0000	**$0.0000**
$0.0061	**$0.0000**
$18,476	$115,671
-$11,079	-$69,362
$7,397	$46,309
$708	$4,434
$230,385	$1,464,251
$14,430	$35,114
$34,437	$77,930

$81,412	$0
-$33,656	$0
$47,756	$0
$1,533	$0
$49,289	$0
$1,204	$6,575
$506	$2,761
$1,451	$7,922
$2,202	$12,022
$5,362	**$29,281**
$81,412	$0
$374,541	$2,122,678

2013 Cost A

Sheet O3.2 Substation Transformers Unit Cost

ALLOCATION BY RATE CLASSIFICATION

Description	Total
Depreciation on Acct 1820-2 Distribution Station Equipment	$780
Depreciation on Acct 1825-2 Storage Battery Equipment	$0
Depreciation on Acct 1805-2 Land Station <50 kV	$0
Depreciation on Acct 1806-2 Land Rights Station <50 kV	$1,294
Depreciation on Acct 1808-2 Buildings and Fixtures < 50 KV	$27,086
Depreciation on Acct 1810-2 Leasehold Improvements <50 kV	$0
Depreciation on General Plant Assigned to Substation Transformers	$3,694
Acct 5012 - Station Buildings and Fixtures Expense	$29,322
Acct 5016 - Distributon Station Equipment - Labour	$1,962
Acct 5017 - Distributon Station Equipment - Other	$520
Acct 5114 - Maintenance of Distribution Station Equipment	$9,805
Allocation of General Expenses	$0
Admin and General Assigned to SubstationTransformers	$5,360
PILs on SubstationTransformers	$9,711
Debt Return on Substation Transformers	$45,065
Equity Return on Substation Transformers	$54,324
Total	**$188,922**
Billed kW without Substation Transformer Allowance	
Billed kWh without Substation Transformer Allowance	
Substation Transformation Unit Cost ($/kW)	
Substation Transformation Unit Cost ($/kWh)	
General Plant - Gross Assets	$4,937,492
General Plant - Accumulated Depreciation	-$2,960,774
General Plant - Net Fixed Assets	$1,976,718
General Plant - Depreciation	$189,285

Total Net Fixed Assets Excluding General Plant	$61,857,596
Total Administration and General Expense	$2,743,214
Total O&M	$6,428,356
Substation Transformer Rate Base Gross Plant	
Acct 1820-2 Distribution Station Equipment	$0
Acct 1825-2 Storage Battery Equipment	$0
Acct 1805-2 Land Station <50 kV	$181,961
Acct 1806-2 Land Rights Station <50 kV	$94,991
Acct 1808-2 Buildings and Fixtures < 50 KV	$1,163,732
Acct 1810-2 Leasehold Improvements <50 kV	$0
Subtotal	***$1,440,683***
Substation Transformers - Accumulated Depreciation	
Acct 1820-2 Distribution Station Equipment	-$15,402
Acct 1825-2 Storage Battery Equipment	$0
Acct 1805-2 Land Station <50 kV	$0
Acct 1806-2 Land Rights Station <50 kV	-$8,395
Acct 1808-2 Buildings and Fixtures < 50 KV	-$208,075
Acct 1810-2 Leasehold Improvements <50 kV	$0
Subtotal	***-$231,873***
Substation Transformers - Net Fixed Assets	$1,208,810
General Plant Assigned to SubstationTransformers - NFA	$38,575
Substation Transformer NFA Including General Plant	$1,247,385
General Expenses	
Acct 5005 - Operation Supervision and Engineering	$273,250
Acct 5010 - Load Dispatching	$114,745
Acct 5085 - Miscellaneous Distribution Expense	$329,209
Acct 5105 - Maintenance Supervision and Engineering	$499,599
Total	$1,216,803
Acct 1820-2 Distribution Station Equipment	$0
Acct 1825-2 Storage Battery Equipment	$0
Total	$0
Acct 1815 - 1855	$86,837,480

Allocation Model

t Worksheet - 1-Staff-2 Updated Cost Allocation Stud

1	2	3	7	8
Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**
$217	$92	$398	$9	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$410	$131	$644	$5	$0
$8,590	$2,748	$13,489	$104	$5
$0	$0	$0	$0	$0
$1,177	$374	$1,837	$14	$1
$9,300	$2,975	$14,602	$112	$5
$545	$231	$1,002	$22	$0
$144	$61	$266	$6	$0
$2,722	$1,152	$5,008	$109	$0
$0	$0	$0	$0	$0
$1,437	$616	$2,784	$63	$0
$3,085	$983	$4,834	$36	$2
$14,315	$4,562	$22,435	$168	$8
$17,256	$5,500	$27,045	$203	$10
$59,197	**$19,424**	**$94,345**	**$851**	**$32**
0	0	1,332,860	23,455	1,356
272,082,836	94,447,805	523,567,859	7,553,004	443,490
$0.0000	**$0.0000**	**$0.0708**	**$0.0363**	**$0.0233**
$0.0002	**$0.0002**	**$0.0002**	**$0.0001**	**$0.0001**
$2,620,627	$561,055	$1,541,392	$55,284	$24,988
-$1,571,463	-$336,437	-$924,298	-$33,151	-$14,984
$1,049,164	$224,618	$617,094	$22,133	$10,004
$100,465	$21,509	$59,091	$2,119	$958

$32,778,185	$7,029,415	$19,354,502	$689,614	$311,244
$1,818,479	$312,186	$535,201	$15,038	$12,765
$4,315,466	$731,637	$1,206,236	$32,904	$29,747
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$57,709	$18,459	$90,617	$697	$33
$30,126	$9,636	$47,306	$364	$17
$369,079	$118,053	$579,543	$4,457	$214
$0	$0	$0	$0	$0
$456,914	***$146,148***	***$717,466***	***$5,517***	***$265***
-$4,275	-$1,810	-$7,866	-$172	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
-$2,663	-$852	-$4,181	-$32	-$2
-$65,991	-$21,108	-$103,622	-$797	-$38
$0	$0	$0	$0	$0
-$72,929	***-$23,769***	***-$115,669***	***-$1,001***	***-$40***
$383,985	$122,379	$601,797	$4,516	$225
$12,291	$3,910	$19,188	$145	$7
$396,276	$126,290	$620,984	$4,661	$232
$145,780	$27,855	$86,661	$3,531	$1,643
$61,217	$11,697	$36,391	$1,483	$690
$175,635	$33,560	$104,408	$4,254	$1,980
$266,538	$50,930	$158,447	$6,456	$3,005
$649,170	$124,042	$385,907	$15,723	$7,318
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$45,850,294	$8,899,430	$27,961,800	$1,118,864	$509,873

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9	10
Unmetered Scattered Load	Embedded Distributor
$0	$64
$0	$0
$0	$0
$1	$101
$27	$2,123
$0	$0
$4	$287
$29	$2,298
$1	$162
$0	$43
$4	$811
$0	$0
$2	$458
$10	$761
$45	$3,530
$55	$4,255
$178	**$14,893**
0	155,806
1,454,727	0
$0.0000	**$0.0956**
$0.0001	**$0.0000**
$18,476	$115,671
-$11,079	-$69,362
$7,397	$46,309
$708	$4,434

$230,385	$1,464,251
$14,430	$35,114
$34,437	$77,930
$0	$0
$0	$0
$182	$14,263
$95	$7,446
$1,165	$91,220
$0	$0
$1,443	***$112,929***
-$6	-$1,273
$0	$0
$0	$0
-$8	-$658
-$208	-$16,310
$0	$0
-$223	***-$18,241***
$1,220	$94,688
$39	$2,995
$1,259	$97,682
$1,204	$6,575
$506	$2,761
$1,451	$7,922
$2,202	$12,022
$5,362	$29,281
$0	$0
$0	$0
$0	$0
$374,541	$2,122,678

2013 Cost

Sheet O3.3 Primary Conductors and Poles C

ALLOCATION BY RATE CLASSIFICATION

Description	Total
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$290,725
Depreciation on Acct 1835-4 Primary Overhead Conductors	$161,937
Depreciation on Acct 1840-4 Primary Underground Conduit	$41,301
Depreciation on Acct 1845-4 Primary Underground Conductors	$315,698
Depreciation on General Plant Assigned to Primary C&P	$67,021
Primary C&P Operations and Maintenance	$572,659
Allocation of General Expenses	$498,550
Admin and General Assigned to Primary C&P	$246,827
PILs on Primary C&P	$175,988
Debt Return on Primary C&P	$816,724
Equity Return on Primary C&P	$984,538
Total	**$4,171,968**
General Plant - Gross Assets	$4,937,492
General Plant - Accumulated Depreciation	-$2,960,774
General Plant - Net Fixed Assets	$1,976,718
General Plant - Depreciation	$189,285
Total Net Fixed Assets Excluding General Plant	$61,857,596
Total Administration and General Expense	$2,743,214
Total O&M	$6,428,356
Primary Conductors and Poles Gross Assets	
Acct 1830-4 Primary Poles, Towers & Fixtures	$14,000,611
Acct 1835-4 Primary Overhead Conductors	$9,251,118
Acct 1840-4 Primary Underground Conduit	$2,636,446

Acct 1845-4 Primary Underground Conductors	$9,701,165
Subtotal	**$35,589,340**
Primary Conductors and Poles Accumulated Depreciation	
Acct 1830-4 Primary Poles, Towers & Fixtures	-$5,991,677
Acct 1835-4 Primary Overhead Conductors	-$3,559,392
Acct 1840-4 Primary Underground Conduit	-$1,139,280
Acct 1845-4 Primary Underground Conductors	-$2,991,204
Subtotal	**-$13,681,553**
Primary Conductor & Pools - Net Fixed Assets	$21,907,788
General Plant Assigned to Primary C&P - NFA	$699,901
Primary C&P Net Fixed Assets Including General Plant	$22,607,688
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0
Acct 1835-3 Bulk Overhead Conductors	$0
Acct 1840-3 Bulk Underground Conduit	$0
Acct 1845-3 Bulk Underground Conductors	$0
Subtotal	**$0**
Acct 1830-5 Secondary Poles, Towers & Fixtures	$3,073,305
Acct 1835-5 Secondary Overhead Conductors	$3,778,626
Acct 1840-5 Secondary Underground Conduit	$11,239,587
Acct 1845-5 Secondary Underground Conductors	$9,320,727
Subtotal	**$27,412,245**
<u>Operations and Maintenance</u>	
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$1,962
Acct 5025 Overhead Distribution Lines & Feeders - Other	$12,752
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$11,990
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$25,403
Acct 5120 Maintenance of Poles, Towers & Fixtures	$75,414
Acct 5125 Maintenance of Overhead Conductors & Devices	$242,022
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$499,535
Acct 5145 Maintenance of Underground Conduit	$56,902
Acct 5150 Maintenance of Underground Conductors & Devices	$82,311
Total	**$1,008,291**
<u>General Expenses</u>	
Acct 5005 - Operation Supervision and Engineering	$273,250
Acct 5010 - Load Dispatching	$114,745
Acct 5085 - Miscellaneous Distribution Expense	$329,209
Acct 5105 - Maintenance Supervision and Engineering	$499,599
Total	**$1,216,803**
Primary Conductors and Poles Gross Assets	$35,589,340
Acct 1815 - 1855	$86,837,480

Grouping of Operation and Maintenance		Total
1830	$	75,414
1835	$	242,022
1840	$	56,902
1845	$	82,311
1830 & 1835	$	539,652
1840 & 1845	$	11,990
Total	**$**	**1,008,291**

Allocation Model

ost Pool Worksheet - 1-Staff-2 Updated Cost Allocati

1	2	3	7	8
Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**
$150,547	$28,478	$90,301	$3,809	$1,834
$83,856	$15,863	$50,299	$2,122	$1,022
$21,387	$4,046	$12,828	$541	$261
$163,478	$30,924	$98,058	$4,137	$1,992
$34,771	$6,566	$20,775	$882	$425
$293,399	$55,156	$175,383	$7,402	$3,593
$260,931	$48,590	$152,562	$6,553	$3,223
$123,634	$23,535	$77,817	$3,383	$1,542
$91,132	$17,239	$54,663	$2,306	$1,110
$422,925	$80,002	$253,679	$10,701	$5,153
$509,825	$96,440	$305,804	$12,900	$6,211
$2,155,886	**$406,839**	**$1,292,170**	**$54,737**	**$26,365**
$2,620,627	$561,055	$1,541,392	$55,284	$24,988
-$1,571,463	-$336,437	-$924,298	-$33,151	-$14,984
$1,049,164	$224,618	$617,094	$22,133	$10,004
$100,465	$21,509	$59,091	$2,119	$958
$32,778,185	$7,029,415	$19,354,502	$689,614	$311,244
$1,818,479	$312,186	$535,201	$15,038	$12,765
$4,315,466	$731,637	$1,206,236	$32,904	$29,747
$7,249,960	$1,371,425	$4,348,676	$183,449	$88,329
$4,790,522	$906,190	$2,873,455	$121,216	$58,365
$1,365,235	$258,252	$818,897	$34,545	$16,633

$5,023,570	$950,274	$3,013,242	$127,113	$61,204
$18,429,288	**$3,486,142**	**$11,054,269**	**$466,324**	**$224,531**
-$3,102,680	-$586,913	-$1,861,052	-$78,508	-$37,801
-$1,843,166	-$348,659	-$1,105,569	-$46,638	-$22,456
-$589,955	-$111,598	-$353,867	-$14,928	-$7,188
-$1,548,940	-$293,002	-$929,087	-$39,193	-$18,871
-$7,084,741	**-$1,340,172**	**-$4,249,575**	**-$179,268**	**-$86,316**
$11,344,546	$2,145,970	$6,804,694	$287,056	$138,215
$363,116	$68,572	$216,959	$9,213	$4,442
$11,707,662	$2,214,542	$7,021,653	$296,268	$142,657
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	**$0**	**$0**	**$0**	**$0**
$1,653,401	$327,053	$1,016,579	$42,746	$19,400
$2,032,855	$402,111	$1,249,883	$52,556	$23,853
$6,046,763	$1,196,086	$3,717,798	$156,328	$70,950
$5,014,439	$991,886	$3,083,083	$129,639	$58,838
$14,747,458	**$2,917,136**	**$9,067,344**	**$381,267**	**$173,041**
$1,025	$196	$618	$26	$12
$6,662	$1,274	$4,019	$169	$80
$0	$0	$0	$0	$0
$6,360	$1,238	$3,875	$163	$76
$0	$0	$0	$0	$0
$13,271	$2,537	$8,007	$338	$160
$39,325	$7,502	$23,698	$999	$476
$126,741	$24,301	$76,589	$3,228	$1,527
$260,967	$49,894	$157,452	$6,637	$3,152
$30,395	$5,964	$18,604	$783	$359
$43,436	$8,404	$26,380	$1,111	$519
$528,182	**$101,310**	**$319,243**	**$13,454**	**$6,362**
$145,780	$27,855	$86,661	$3,531	$1,643
$61,217	$11,697	$36,391	$1,483	$690
$175,635	$33,560	$104,408	$4,254	$1,980
$266,538	$50,930	$158,447	$6,456	$3,005
$649,170	**$124,042**	**$385,907**	**$15,723**	**$7,318**
$18,429,288	$3,486,142	$11,054,269	$466,324	$224,531
$45,850,294	$8,899,430	$27,961,800	$1,118,864	$509,873

Residential	GS <50	GS>50-Regular	Street Light	Sentinel
$ 39,325	$ 7,502	$ 23,698	$ 999	$ 476
$ 126,741	$ 24,301	$ 76,589	$ 3,228	$ 1,527
$ 30,395	$ 5,964	$ 18,604	$ 783	$ 359
$ 43,436	$ 8,404	$ 26,380	$ 1,111	$ 519
$ 281,925	$ 53,901	$ 170,097	$ 7,170	$ 3,405
$ 6,360	$ 1,238	$ 3,875	$ 163	$ 76
$ 528,182	**$ 101,310**	**$ 319,243**	**$ 13,454**	**$ 6,362**

ion Study

9	10
Unmetered Scattered Load	**Embedded Distributor**
$1,328	$14,428
$740	$8,037
$189	$2,050
$1,442	$15,668
$308	$3,293
$2,599	$35,126
$2,327	$24,364
$1,089	$15,828
$804	$8,734
$3,730	$40,533
$4,497	$48,861
$19,051	**$216,921**
$18,476	$115,671
-$11,079	-$69,362
$7,397	$46,309
$708	$4,434
$230,385	$1,464,251
$14,430	$35,114
$34,437	$77,930
$63,943	$694,829
$42,251	$459,119
$12,041	$130,843

$44,307	$481,454
$162,541	**$1,766,246**
-$27,365	-$297,358
-$16,256	-$176,647
-$5,203	-$56,541
-$13,661	-$148,449
-$62,485	**-$678,995**
$100,056	$1,087,251
$3,212	$34,386
$103,268	$1,121,636
$0	$0
$0	$0
$0	$0
$0	$0
$0	**$0**
$14,126	$0
$17,368	$0
$51,662	$0
$42,842	$0
$125,999	**$0**
$9	$75
$58	$489
$0	$0
$55	$223
$0	$0
$116	$974
$345	$3,069
$1,107	$8,528
$2,285	$19,148
$261	$537
$377	$2,083
$4,614	**$35,126**
$1,204	$6,575
$506	$2,761
$1,451	$7,922
$2,202	$12,022
$5,362	**$29,281**
$162,541	$1,766,246
$374,541	$2,122,678

Unmetered Scattered Load	Embedded Distributor
$ 345	$ 3,069
$ 1,107	$ 8,528
$ 261	$ 537
$ 377	$ 2,083
$ 2,468	$ 20,686
$ 55	$ 223
$ 4,614	**$ 35,126**

2013 Cost

Sheet O3.4 Secondary Cost Pool Worksheet

ALLOCATION BY RATE CLASSIFICATION

Description	Total
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$63,818
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$66,143
Depreciation on Acct 1840-5 Secondary Underground Conduit	$176,073
Depreciation on Acct 1845-5 Secondary Underground Conductors	$303,317
Depreciation on General Plant Assigned to Secondary C&P	$51,765
Secondary C&P Operations and Maintenance	$435,632
Allocation of General Expenses	$384,247
Admin and General Assigned to Primary C&P	$187,256
PILs on Secondary C&P	$135,859
Debt Return on Secondary C&P	$630,493
Equity Return on Secondary C&P	$760,042
Total	**$3,194,644**
General Plant - Gross Assets	$4,937,492
General Plant - Accumulated Depreciation	-$2,960,774
General Plant - Net Fixed Assets	$1,976,718
General Plant - Depreciation	$189,285
Total Net Fixed Assets Excluding General Plant	**$61,857,596**
Total Administration and General Expense	**$2,743,214**
Total O&M	**$6,428,356**
Secondary Conductors and Poles Gross Plant	
Acct 1830-5 Secondary Poles, Towers & Fixtures	$3,073,305
Acct 1835-5 Secondary Overhead Conductors	$3,778,626
Acct 1840-5 Secondary Underground Conduit	$11,239,587
Acct 1845-5 Secondary Underground Conductors	$9,320,727

Subtotal	***$27,412,245***
<u>**Secondary Conductors and Poles Accumulated Depreciation**</u>	
Acct 1830-5 Secondary Poles, Towers & Fixtures	-$1,315,246
Acct 1835-5 Secondary Overhead Conductors	-$1,453,836
Acct 1840-5 Secondary Underground Conduit	-$4,856,929
Acct 1845-5 Secondary Underground Conductors	-$2,873,902
Subtotal	***-$10,499,914***
Secondary Conductor & Pools - Net Fixed Assets	$16,912,331
General Plant Assigned to Secondary C&P - NFA	$540,580
Secondary C&P Net Fixed Assets Including General Plant	$17,452,910
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0
Acct 1835-3 Bulk Overhead Conductors	$0
Acct 1840-3 Bulk Underground Conduit	$0
Acct 1845-3 Bulk Underground Conductors	$0
Subtotal	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$14,000,611
Acct 1835-4 Primary Overhead Conductors	$9,251,118
Acct 1840-4 Primary Underground Conduit	$2,636,446
Acct 1845-4 Primary Underground Conductors	$9,701,165
Subtotal	***$35,589,340***
<u>**Operations and Maintenance**</u>	
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$1,962
Acct 5025 Overhead Distribution Lines & Feeders - Other	$12,752
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$11,990
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$25,403
Acct 5120 Maintenance of Poles, Towers & Fixtures	$75,414
Acct 5125 Maintenance of Overhead Conductors & Devices	$242,022
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$499,535
Acct 5145 Maintenance of Underground Conduit	$56,902
Acct 5150 Maintenance of Underground Conductors & Devices	$82,311
Total	**$1,008,291**
<u>**General Expenses**</u>	
Acct 5005 - Operation Supervision and Engineering	$273,250
Acct 5010 - Load Dispatching	$114,745
Acct 5085 - Miscellaneous Distribution Expense	$329,209
Acct 5105 - Maintenance Supervision and Engineering	$499,599
Total	**$1,216,803**
Secondary Conductors and Poles Gross Assets	$27,412,245
Acct 1815 - 1855	$86,837,480

Grouping of Operation and Maintenance		Total
1830	$	75,414
1835	$	242,022
1840	$	56,902
1845	$	82,311
1830 & 1835	$	539,652
1840 & 1845	$	11,990
Total	**$**	**1,008,291**

: Allocation Model

: - 1-Staff-2 Updated Cost Allocation Study

1	2	3	7	8
Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**
$34,333	$6,791	$21,109	$888	$403
$35,584	$7,039	$21,879	$920	$418
$94,725	$18,737	$58,241	$2,449	$1,111
$163,181	$32,278	$100,330	$4,219	$1,915
$27,887	$5,507	$17,080	$723	$329
$234,783	$46,154	$143,860	$6,052	$2,769
$208,801	$40,660	$125,140	$5,358	$2,484
$98,934	$19,694	$63,830	$2,766	$1,188
$73,090	$14,458	$44,939	$1,890	$858
$339,198	$67,095	$208,553	$8,769	$3,980
$408,893	$80,882	$251,404	$10,571	$4,798
$1,719,411	**$339,294**	**$1,056,365**	**$44,604**	**$20,252**
$2,620,627	$561,055	$1,541,392	$55,284	$24,988
-$1,571,463	-$336,437	-$924,298	-$33,151	-$14,984
$1,049,164	$224,618	$617,094	$22,133	$10,004
$100,465	$21,509	$59,091	$2,119	$958
$32,778,185	**$7,029,415**	**$19,354,502**	**$689,614**	**$311,244**
$1,818,479	**$312,186**	**$535,201**	**$15,038**	**$12,765**
$4,315,466	**$731,637**	**$1,206,236**	**$32,904**	**$29,747**
$1,653,401	$327,053	$1,016,579	$42,746	$19,400
$2,032,855	$402,111	$1,249,883	$52,556	$23,853
$6,046,763	$1,196,086	$3,717,798	$156,328	$70,950
$5,014,439	$991,886	$3,083,083	$129,639	$58,838

$14,747,458	***$2,917,136***	***$9,067,344***	***$381,267***	***$173,041***
-$707,587	-$139,965	-$435,053	-$18,293	-$8,303
-$782,146	-$154,713	-$480,896	-$20,221	-$9,177
-$2,612,970	-$516,861	-$1,606,561	-$67,553	-$30,660
-$1,546,125	-$305,833	-$950,621	-$39,972	-$18,142
-$5,648,827	***-$1,117,372***	***-$3,473,131***	***-$146,040***	***-$66,281***
$9,098,631	$1,799,764	$5,594,212	$235,228	$106,760
$291,229	$57,510	$178,364	$7,549	$3,431
$9,389,859	$1,857,273	$5,772,577	$242,777	$110,191
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	$0	$0	$0	$0
$0	***$0***	***$0***	***$0***	***$0***
$7,249,960	$1,371,425	$4,348,676	$183,449	$88,329
$4,790,522	$906,190	$2,873,455	$121,216	$58,365
$1,365,235	$258,252	$818,897	$34,545	$16,633
$5,023,570	$950,274	$3,013,242	$127,113	$61,204
$18,429,288	***$3,486,142***	***$11,054,269***	***$466,324***	***$224,531***
$1,025	$196	$618	$26	$12
$6,662	$1,274	$4,019	$169	$80
$0	$0	$0	$0	$0
$6,360	$1,238	$3,875	$163	$76
$0	$0	$0	$0	$0
$13,271	$2,537	$8,007	$338	$160
$39,325	$7,502	$23,698	$999	$476
$126,741	$24,301	$76,589	$3,228	$1,527
$260,967	$49,894	$157,452	$6,637	$3,152
$30,395	$5,964	$18,604	$783	$359
$43,436	$8,404	$26,380	$1,111	$519
$528,182	**$101,310**	**$319,243**	**$13,454**	**$6,362**
$145,780	$27,855	$86,661	$3,531	$1,643
$61,217	$11,697	$36,391	$1,483	$690
$175,635	$33,560	$104,408	$4,254	$1,980
$266,538	$50,930	$158,447	$6,456	$3,005
$649,170	**$124,042**	**$385,907**	**$15,723**	**$7,318**
$14,747,458	$2,917,136	$9,067,344	$381,267	$173,041
$45,850,294	$8,899,430	$27,961,800	$1,118,864	$509,873

Residential	GS <50	GS>50-Regular	Street Light	Sentinel
$ 39,325	$ 7,502	$ 23,698	$ 999	$ 476
$ 126,741	$ 24,301	$ 76,589	$ 3,228	$ 1,527
$ 30,395	$ 5,964	$ 18,604	$ 783	$ 359
$ 43,436	$ 8,404	$ 26,380	$ 1,111	$ 519
$ 281,925	$ 53,901	$ 170,097	$ 7,170	$ 3,405
$ 6,360	$ 1,238	$ 3,875	$ 163	$ 76
$ 528,182	**$ 101,310**	**$ 319,243**	**$ 13,454**	**$ 6,362**

9	10
Unmetered Scattered Load	**Embedded Distributor**
$293	$0
$304	$0
$809	$0
$1,394	$0
$239	$0
$2,015	$0
$1,804	$0
$844	$0
$624	$0
$2,898	$0
$3,493	$0
$14,719	**$0**
$18,476	$115,671
-$11,079	-$69,362
$7,397	$46,309
$708	$4,434
$230,385	**$1,464,251**
$14,430	**$35,114**
$34,437	**$77,930**
$14,126	$0
$17,368	$0
$51,662	$0
$42,842	$0

$125,999	***$0***
-$6,045	$0
-$6,682	$0
-$22,325	$0
-$13,210	$0
-$48,262	***$0***
$77,737	$0
$2,496	$0
$80,232	$0
$0	$0
$0	$0
$0	$0
$0	$0
$0	***$0***
$63,943	$694,829
$42,251	$459,119
$12,041	$130,843
$44,307	$481,454
$162,541	***$1,766,246***
$9	$75
$58	$489
$0	$0
$55	$223
$0	$0
$116	$974
$345	$3,069
$1,107	$8,528
$2,285	$19,148
$261	$537
$377	$2,083
$4,614	**$35,126**
$1,204	$6,575
$506	$2,761
$1,451	$7,922
$2,202	$12,022
$5,362	**$29,281**
$125,999	$0
$374,541	$2,122,678

Unmetered Scattered Load	Embedded Distributor
$ 345	$ 3,069
$ 1,107	$ 8,528
$ 261	$ 537
$ 377	$ 2,083
$ 2,468	$ 20,686
$ 55	$ 223
$ 4,614	**$ 35,126**

2013 Cost A

Sheet O3.5 USL Metering Credit Worksheet - 1

ALLOCATION BY RATE CLASSIFICATION

Description	GS <50
Depreciation on Acct 1860 Metering	$162,240
Depreciation on General Plant Assigned to Metering	$4,247
Acct 5065 - Meter expense	$124,583
Acct 5070 & 5075 - Customer Premises	$363
Acct 5175 - Meter Maintenance	$0
Acct 5310 - Meter Reading	$17,106
Admin and General Assigned to Metering	$60,613
PILs on Metering	$11,149
Debt Return on Metering	$51,740
Equity Return on Metering	$62,371
Total	$494,412
Number of Customers	2,764
Metering Unit Cost ($/Customer/Month)	**$14.91**
General Plant - Gross Assets	$561,055
General Plant - Accumulated Depreciation	-$336,437
General Plant - Net Fixed Assets	$224,618
General Plant - Depreciation	$21,509
Total Net Fixed Assets Excluding General Plant	$7,029,415
Total Administration and General Expense	$312,186
Total O&M	$731,637
Metering Rate Base	

Acct 1860 - Metering - Gross Assets	$1,964,825
Metering - Accumulated Depreciation	-$576,948
Metering - Net Fixed Assets	$1,387,877
General Plant Assigned to Metering - NFA	$44,348
Metering Net Fixed Assets Including General Plant	$1,432,225

llocation Model

-Staff-2 Updated Cost Allocation Study

2013 Cost Allo

Sheet O3.6 MicroFIT Charge Worksheet - 1-Staff-2

Instructions:
More Instructions provided on the first tab in this workbook.

ALLOCATION BY RATE CLASSIFICATION

Description	**Residential**	**Monthly Unit Cost**
Customer Premises - Operations Labour (5070)	$ 4,647.47	$ 0.01
Customer Premises - Materials and Expenses (5075)	$ -	$ -
Meter Expenses (5065)	$ 352,933.22	$ 0.83
Maintenance of Meters (5175)	$ -	$ -
Meter Reading Expenses (5310)	$ 211,877.35	$ 0.50
Customer Billing (5315)	$ 757,164.04	$ 1.78
Amortization Expense - General Plant Assigned to Meters	$ 12,050.84	$ 0.03
Admin and General Expenses allocated to O&M expenses for meters	$ 217,364.42	$ 0.51
Allocated PILS (general plant assigned to meters)	$ 979.59	$ 0.00
Interest Expense	$ 4,546.09	$ 0.01
Income Expenses	$ 5,480.19	$ 0.01
Total Cost	$ 1,567,043.21	$ 3.69
Number of Residential Customers	35363.71327	

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Updated Cost Allocation Study