

Borden Ladner Gervais LLP
Lawyers • Patent & Trade-mark Agents
Scotia Plaza, 40 King Street West
Toronto, Ontario, Canada M5H 3Y4
tel.: (416) 367-6000 fax: (416) 367-6749
www.blgcanada.com

JAMES C. SIDLOFSKY
direct tel.: 416-367-6277
direct fax: 416-361-2751
e-mail: jsidlofsky@blgcanada.com



**BORDEN
LADNER
GERVAIS**

May 15, 2008

Delivered by Courier

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

Dear Ms. Walli:

**Re: EB-2007-0698
Brantford Power Inc.
Application to the Ontario Energy Board for Electricity Distribution
Rates and Charges as of May 1, 2008**

We are counsel to Brantford Power Inc. ("BPI") with respect to the above-captioned matter. Please find accompanying this letter 2 hard copies of the revised response to OEB Staff Question 8.7a.i. printed on blue paper, together with a revised first page of the responses, indicating today's update to that response. We also enclose a replacement disk containing a complete updated version of the responses.

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

Yours very truly,
BORDEN LADNER GERVAIS LLP

Original Signed by James C. Sidlofsky

James C. Sidlofsky
JCS/dp
Encls.

cc: G. Mychailenko, BPI
H. Wyatt, BPI
N. Butt, BPI
K. Mitchell, BPI
Intervenors of Record (Sent by electronic copy only)

Vancouver
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JAMES C. SIDLOFSKY
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e-mail: jsidlofsky@blgcanada.com

May 8, 2008

Delivered by Courier

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

Dear Ms. Walli:

**Re: EB-2007-0698
Brantford Power Inc.
Application to the Ontario Energy Board for Electricity Distribution
Rates and Charges as of May 1, 2008**

We are counsel to Brantford Power Inc. (“BPI”) with respect to the above-captioned matter. Please find accompanying this letter hard copies of clean replacement pages and a replacement disk containing BPI’s revised responses to the interrogatories of the Ontario Energy Board Staff as discussed in my e-mail message sent Tuesday, May 6, 2008, a copy of which accompanies this letter for your reference. Also on the disk is an Excel version of the Schedule detailing adjustments made to BPI’s 2006 EDR approved balances, referred to in Staff Question 12.5(e).

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

Yours very truly,
BORDEN LADNER GERVAIS LLP

Original Signed by James C. Sidlofsky

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Intervenors of Record (Sent by electronic copy only)

Vancouver
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Calgary

Sidlofsky, James C.

From: Sidlofsky, James C.
Sent: May 6, 2008 3:02 PM
To: OEB submissions; Batul Rahimtoola
Cc: hwyatt@brantford.ca; bwilliams@opsba.org; john.devellis@shibleyrighton.com; rachel.chen@ieai.ca; gmychailenko@brantford.ca; nbutt@brantford.ca; 'KiMitchell@brantford.ca'
Subject: Brantford Power responses to OEB Staff Interrogatories - EB-2007-0698

We are counsel to Brantford Power Inc. ("BPI") in the above captioned matter. BPI's responses to the OEB staff interrogatories were delivered to the OEB yesterday, and a disk containing electronic copies of those responses is being delivered to Mr. DeVellis today.

Please note that a number of editing marks were inadvertently included in a small number of pages of the text of the responses. These marks can be seen at pages 43-50, 53 and 111. We have removed those marks and have corrected the repetition of the number "9" and a typographical error in the word "Schedule" in the title and reference of Question 9 at the top of page 110. We will provide copies of clean replacement pages and a replacement disk tomorrow, but we note that there is no change to the text of the responses arising out of the removal of these marks.

We regret any confusion this may have caused.

James C. Sidlofsky
Partner
Borden Ladner Gervais LLP
40 King Street West
Toronto ON M5H 3Y4
Tel.: 416-367-6277 Fax: 416-361-2751
www.blgcanada.com
E-mail: jsidlofsky@blgcanada.com

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JAMES C. SIDLOFSKY
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May 5, 2008

Delivered by Courier

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

Dear Ms. Walli:

**Re: EB-2007-0698
Brantford Power Inc.
Application to the Ontario Energy Board for Electricity Distribution
Rates and Charges as of May 1, 2008**

We are counsel to Brantford Power Inc. (“BPI”) with respect to the above-captioned matter. Please find accompanying this letter two hard copies of BPI’s responses to the interrogatories of the Ontario Energy Board Staff in this proceeding, together with an electronic version of same.

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

Yours very truly,

BORDEN LADNER GERVAIS LLP

Original Signed by Diana Pereira on behalf of James C. Sidlofsky

James C. Sidlofsky
JCS/dp

Encls.

cc: G. Mychailenko, BPI
H. Wyatt, BPI
N. Butt, BPI
K. Mitchell, BPI
Intervenors of Record (Sent by electronic copy only)

Vancouver
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Calgary

IN THE MATTER OF the *Ontario Energy Board Act* 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Brantford Power Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the distribution of electricity commencing May 1, 2008.

**BRANTFORD POWER INC. RESPONSES TO
OEB STAFF INTERROGATORIES**

**DELIVERED MAY 5, 2008
REPLACEMENT VERSION MAY 8, 2008
(Editing marks removed – no changes to responses)
UPDATED MAY 15, 2008 (Response to Question 8.7a.i.)**

1 OPERATING EXPENSES

OM&A EXPENSES – OVERALL

1.1 Ref: Exhibit(s) Exhibit 4

BPI has indicated that a new capitalization policy was approved by its Board in 2006.

- a. Please state whether or not this new policy has resulted in BPI making changes to the company's accounting policies in respect to capitalization of operation expenses and/or making significant changes to accounting estimates used in allocation of costs between operations and capital expenses post fiscal year end 2006.

RESPONSE:

Yes, the new policy has resulted in changes to the accounting policies in respect to the capitalization of operating expenses including making significant changes to accounting estimates in allocation of costs between operations and capital expenses. These changes were not only implemented for the period following fiscal year end 2006 but were also reflected in the 2006 actual fiscal year end figures.

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

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 May 1, 2008.

BRANTFORD POWER INC.

2008 ELECTRICITY DISTRIBUTION RATE APPLICATION

**RESPONSES TO ONTARIO ENERGY BOARD STAFF (“OEB STAFF”)
INTERROGATORIES**

FILED: MAY 5, 2008

REPLACEMENT VERSION MAY 8, 2008

(Editing marks removed from responses – no changes to responses)

Applicant

Brantford Power Inc.
84 Market Street
Brantford, ON N3T 5N8

George Mychailenko

President
Tel: (519) 756-8528 Ext. 3226
Fax: (519) 751-3522
GMychailenko@brantford.ca

Heather Wyatt

Manager of Regulatory Compliance and
Governance, Board Secretary
Tel: (519) 751-3522 Ext. 3269
Fax: (519) 753-6130

Counsel to the Applicant

Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street West
Toronto, Ontario M5H 3Y4

James C. Sidlofsky

Tel: (416) 367-6277
Fax: (416) 361-2751
jsidlofsky@blgcanada.com

EB-2007-0698

BRANTFORD POWER INC.

2008 ELECTRICITY DISTRIBUTION RATE APPLICATION

**RESPONSES TO THE ONTARIO ENERGY BOARD STAFF (“OEB STAFF”)
INTERROGATORIES**

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1	<i>Responses to OEB Staff Interrogatories</i>
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Q	OEB Staff Question 12.2c
R	OEB Staff Question 12.5e

**IN THE MATTER OF the *Ontario Energy Board Act*
1998, S.O. 1998, c. 15, (Schedule B);**

**AND IN THE MATTER OF an Application by Brantford
Power Inc. for an Order or Orders approving or fixing
just and reasonable rates and other charges for the
distribution of electricity commencing May 1, 2008.**

**BRANTFORD POWER INC. RESPONSES TO
OEB STAFF INTERROGATORIES**

**DELIVERED MAY 5, 2008
REPLACEMENT VERSION MAY 8, 2008
(Editing marks removed – no changes to responses)**

1 OPERATING EXPENSES

OM&A EXPENSES – OVERALL

1.1 Ref: Exhibit(s) Exhibit 4

BPI has indicated that a new capitalization policy was approved by its Board in 2006.

- a. Please state whether or not this new policy has resulted in BPI making changes to the company's accounting policies in respect to capitalization of operation expenses and/or making significant changes to accounting estimates used in allocation of costs between operations and capital expenses post fiscal year end 2006.

RESPONSE:

Yes, the new policy has resulted in changes to the accounting policies in respect to the capitalization of operating expenses including making significant changes to accounting estimates in allocation of costs between operations and capital expenses. These changes were not only implemented for the period following fiscal year end 2006 but were also reflected in the 2006 actual fiscal year end figures.

- b. If confirmed, please provide a discussion highlighting the impact of the changes.

RESPONSE:

BPI, as part of its ongoing review of business processes, undertook a review of its existing capitalization policy and related accounting processes. Please refer to School Energy Coalition Interrogatory 3 part d details.

It is important to note that the new capitalization policy resulted in a two-staged cost allocation process as outlined on the attached flow chart (please see Attachment A). Firstly the applicable share of indirect costs is attributed 100% to the applicable direct expense activity. This initial cost allocation process determines the fully absorbed gross costs of each distinct department or service area. At this stage no costs have been capitalized. As a result of this indirect cost allocation step, a department or service area that does not support the capital program may have different reported costs than was historically the case as it now has absorbed its share of indirect costs.

The second cost allocation step accomplishes the capitalization of indirect costs by transferring an appropriate amount of these fully absorbed costs to the capital and recoverable works programs based on the labour units supporting these non OM&A cost activities. Once this allocation is completed, the costs remaining in OM&A represent the fully absorbed OM&A costs.

The resulting level of OM&A costs will depend on how much indirect costs were assigned to a particular department or service area in the first cost allocation step and the extent that department or service area contributes to the capital and recoverable works programs in the second stage of the cost allocation process. A department or service area not involved in the capital program could reflect a change in the reported OM&A as it will now include their respective share of indirect costs.

The flow chart in Attachment A illustrates the capitalization policy cost allocation process.

1.2 Exhibit 4/Tab 1/Schedule 2/page 1

Board Staff Table 1 below was prepared to review BPI's OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below.

Table 1

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A Expenses				
Operations	580,929	793,192	1,176,926	1,090,412
Maintenance	2,006,136	1,521,089	1,870,016	1,884,681
Billing & Collecting	905,817	1,900,231	2,145,847	2,302,509
Community Relations	446,549	326,422	190,140	139,091
Administrative and General Expenses	3,437,561	1,984,087	2,634,367	2,783,384
Total Controllable Expenses	7,376,992	6,525,021	8,017,296	8,200,077
Low Voltage		-	-	-
CDM				
Taxes other than income	162,777	9,635	12,459	12,298
Amortization Expense	2,476,213	2,556,007	2,781,345	3,027,657
Total Distribution Expenses	10,015,982	9,090,663	10,811,100	11,240,032
LCT, OCT & Income Taxes	1,676,871	2,690,785	2,571,188	1,889,507
Total Operating Costs	11,692,853	11,781,448	13,382,288	13,129,539

Board Staff Table 2 below was created to review BPI's OM&A forecasted expenses from the evidence provided in the application's Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions. Then indicated percentages are the proportions of the total variance that each line item contributes. By way of example, 4.6% of the 25.7% variance between 2006 and 2008 is from Operations.

Table 2

	2006 Board Approved	Variance 2006/2006	2006 Actual	Variance 2007/2006	2007 Bridge	Variance 2008/2007	2008 Test	Variance 2008/2006
OM&A Expenses								
Operations	580,929	212,263 2.9%	793,192	383,734 5.2%	1,176,926	- 86,514 -1.1%	1,090,412	297,220 4.6%
Maintenance	2,006,136	- 485,047 -6.6%	1,521,089	348,927 4.7%	1,870,016	14,665 0.2%	1,884,681	363,592 5.6%
Billing & Collecting	905,817	994,414 13.5%	1,900,231	245,016 3.3%	2,145,847	156,662 2.0%	2,302,509	402,278 6.2%
Community Relations	446,549	- 120,127 -1.6%	326,422	- 136,282 -1.8%	190,140	- 51,049 -0.6%	139,091	- 187,331 -2.9%
Administrative and General Expenses	3,437,561	- 1,453,474 -19.7%	1,984,087	650,280 8.8%	2,634,367	149,017 1.9%	2,783,384	799,297 12.2%
Total Controllable Expenses	7,376,992	- 851,971 -11.5%	6,525,021	1,492,275 22.9%	8,017,296	182,781 2.3%	8,200,077	1,675,056 25.7%

- (a) Please confirm that BPI agrees with the two tables prepared by Board Staff above. If BPI does not agree with any table, please advise why not. If BPI determines that the table requires modification due to the difference reconciliation resulting from Board staff Table 1 above, please provide amended tables with full explanation of changes made.

RESPONSE:

- a) Table 1 contained input errors, requiring the values for LCT, OCT & Income Taxes for years 2007 Bridge and 2008 Test to be replaced with the correct values. Please see the replacement Table 1 below.

No change is necessary to Table 2.

Table 1 Revised

OM&A EXPENSES	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Operations	580,929	793,192	1,176,926	1,090,412
Maintenance	2,006,136	1,521,089	1,870,016	1,884,681
Billing & Collecting	905,817	1,900,231	2,145,847	2,302,509
Community Relations	446,549	326,422	190,140	139,091
Administration and General Expenses	3,437,561	1,984,087	2,634,367	2,783,384
Total Controllable Expenses	7,376,992	6,525,021	8,017,296	8,200,077

Low Voltage	-	-	-	-
CDM	-	-	-	-
Taxes other than income	162,777	9,635	12,459	12,298
Amortization Expense	2,476,213	2,556,007	2,781,345	3,027,657
Total Distribution Expenses	10,015,982	9,090,663	10,811,100	11,240,032
LCT, OCT & Income Taxes	1,676,871	2,690,785	2,704,197	2,025,315
Total Operating Costs	11,692,853	11,781,448	13,515,297	13,265,347

(b) Please provide a table identifying and explaining the key cost drivers that are contributing to the overall increase of 25.7% over 2006 Historical relative to 2008.

RESPONSE:

**Total Controllable Expenses per Board Staff Table 1
2006 Historical vs 2008 Test**

Increase in Directs	\$	857,993	15.51%
Increase in Indirects		701,094	34.42%
Decrease in amount of Indirects allocated to capital/billable		116,650	-11.23%
Overall Increase		1,675,737	25.67%

Increase in Directs:

Salaries and benefits	1	523	61.0%
Supplies	2	146	17.0%
Fleet	3	93	10.8%
Regulatory Costs	4	97	11.3%
Net of other increases and decreases		(1)	-0.1%
		858	100.0%

Increase in Indirects:

Insurance	5	28	4.0%
Accounting & Audit		(63)	-9.0%
IT	6	220	31.4%
Property	7	209	29.8%
Stores/Dispatch/Bldg		34	4.9%
Inventory OH Recovery	8	124	17.7%
Retirees Post-Employment Benefit Liability		45	6.4%
Energy Board Costs		31	4.4%
Net of other increases and decreases		73	10.4%
		701	100.0%

Explanations:

2 Supplies

Increase attributable primarily to Operations. Operation spending on supplies dipped in 2006 as compared to both budget and actuals in preceding years. Budgeted amounts have declined each year from 2005 to 2008.

	Year 2004	2005	2006	2007	2008
Budget	327	375	307	286	279
Actual/Bridge	622	219	138	277	
Variance to Budget	295	-156	-169	-9	-279

3Fleet

Fleet clearing account established in 2007 in accordance with OEB APH Article 340. Article 340, Rolling Stock Operation, p12, states that any residual balance remaining after regular distribution shall be cleared to applicable plant and operating accounts on a basis which will distribute the costs equitably. Fleet costs increases have remained relatively stable since 2005. 2006 Historical reflects over distribution of costs to capital and billable vs OM&A. This type of misallocation has been rectified in 2007 and 2008 projections which is primary cause for increase in fleet costs between 2006 Historical and 2008 Test.

	Year 2004	2005	2006	2007	2008
Actual/Bridge	386	484	554	520	520

5Insurance

Increase attributable to normal rate increases experienced for liability, fleet, and BPI owned property.

	Year 2004	2005	2006	2007	2008
Budget	154	161	195	216	196
Actual/Bridge	161	171	168	196	
Variance to Budget	8	10	(27)	(20)	(196)

8Inventory Overhead Recovery

This is a clearing account that accumulates inventory mark-up applied to items relieved from inventory to recover overheads incurred in the procurement and handling of BPI's inventory. A decrease in recovery amount from 2006 Historical vs 2008 Test Year reflects a reduction in the projected amount and or value of the inventory to be used in 2008.

Several other explanations can be found in BPI's responses to School Energy Coalition Interrogatory 17a), including Salaries and benefits (1), Regulatory costs (4), I.T.(6) and Property Management (7).

1.3 Ref: Exhibit 4/Tab 1/Schedule 2

On page 1 of the above schedule, BPI discloses the following information for “Taxes other than income taxes”

Table 3

	2006 Board Approved	2006 Actual	Variance
Taxes other than income	162,777	9,635	153,142

Please provide an explanation for the variance noted in table 3 above the \$153, 142.

RESPONSE:

The 2006 Actual value in account 6105 of \$9,635 does not include \$127,000 in capital taxes, which were mapped to USoA account 6110 in the 2006 OEB trial balance. If the capital taxes had been reported in the 6105 account, the 2006 total would be \$136,635. The balance of the variance from the 2006 Board Approved balance of \$162,777 to the revised 2006 Actual of \$136,635 is \$26,412. This is caused by a decrease in PILs Property Tax paid as a result of a continuing detailed review of the properties that had originally been included in BPI's PILs Property Tax return, filed annually, but were no longer owned by BPI.

1.4 Ref: Exhibit 4/Tab 2/Schedule 1 to 3

In Schedule 1, BPI presents their OM&A Costs Table and in the following two schedules, various breakdowns and explanations of these numbers. In table 4 below, Board Staff has identified variances between 2006 actual and the 2008 test year for certain operating costs where the percent changes are significant. Please provide additional explanation for the changes.

Table 4

Operations (Working Capital)	2006 Actual	2008 Test Year	Variance	% Increase
5005-Operation Supervision and Engineering	\$ 205,800	\$ 266,919	\$ 61,119	30%
5010-Load Dispatching	\$ 9,292	\$ 17,887	\$ 8,595	92%
5012-Station Buildings and Fixtures Expense	\$ 28,746	\$ 39,832	\$ 11,086	39%
5014-Transformer Station Equipment - Operation Labour	\$ 591	\$ 6,778	\$ 6,187	1047%
5015-Transformer Station Equipment - Operation Supplies and Expenses	\$ 51,541	\$ 55,950	\$ 4,409	9%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	\$ 8,145	\$ 15,081	\$ 6,936	85%
5035-Overhead Distribution Transformers- Operation	\$ 4,625	\$ 16,167	\$ 11,542	250%
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	\$ 11,471	\$ 20,669	\$ 9,198	80%
5065-Meter Expense	\$ 359,201	\$ 494,376	\$ 135,175	38%
5070-Customer Premises - Operation Labour	\$ 806	\$ 6,531	\$ 5,725	710%
5085-Miscellaneous Distribution Expense	\$ 96,962	\$ 129,239	\$ 32,277	33%
Maintenance (Working Capital)				
5105-Maintenance Supervision and Engineering	\$ 245,710	\$ 306,914	\$ 61,204	25%
5125-Maintenance of Overhead Conductors and Devices	\$ 190,931	\$ 212,429	\$ 21,498	11%
5130-Maintenance of Overhead Services	\$ 196,674	\$ 219,810	\$ 23,136	12%
5135-Overhead Distribution Lines and Feeders - Right of Way	\$ 328,908	\$ 364,402	\$ 35,494	11%
5145-Maintenance of Underground Conduit	\$ 51,871	\$ 72,896	\$ 21,025	41%
5150-Maintenance of Underground Conductors and Devices	\$ 82,796	\$ 121,982	\$ 39,186	47%
5155-Maintenance of Underground Services	\$ 171,741	\$ 222,899	\$ 51,158	30%
5160-Maintenance of Line Transformers	\$ 71,971	\$ 173,973	\$ 102,002	142%
Billing and Collections				
5305-Supervision	\$ 127,741	\$ 147,522	\$ 19,781	15%
5310-Meter Reading Expense	\$ 383,430	\$ 405,512	\$ 22,082	6%
5315-Customer Billing	\$ 443,457	\$ 509,848	\$ 66,391	15%
5320-Collecting	\$ 283,868	\$ 327,828	\$ 43,960	15%
5330-Collection Charges	\$ 666	\$ 2,459	\$ 1,793	269%
5335-Bad Debt Expense	\$ 157,089	\$ 200,000	\$ 42,911	27%
5340-Miscellaneous Customer Accounts Expenses	\$ 503,980	\$ 709,340	\$ 205,360	41%
Administrative and General Expenses				
5605-Executive Salaries and Expenses	\$ 377,446	\$ 429,070	\$ 51,624	14%
5610-Management Salaries and Expenses	\$ 598,244	\$ 723,218	\$ 124,974	21%
5620-Office Supplies and Expenses	\$ 36,138	\$ 52,654	\$ 16,516	46%
5630-Outside Services Employed	\$ 44,693	\$ 179,500	\$ 134,807	302%
5645-Employee Pensions and Benefits	\$ 49,204	\$ 110,367	\$ 61,163	124%
5655-Regulatory Expenses	\$ 88,064	\$ 215,000	\$ 126,936	144%
5665-Miscellaneous General Expenses	-\$ 112,105	\$ 187,617	\$ 299,722	-267%

For the accounts in Table 4 that are above a materiality threshold of 0.2% of total distribution expenses before taxes:

- a) Please provide a more detailed explanation, identifying the cost drivers, for each of the variances sufficient to allow for a full understanding as to the reasons for the variances. Please show the calculation for the determination of the materiality threshold.

RESPONSE:

Please refer to BPI's response to School Energy Coalition IR #15 for explanations of variances for accounts shown in Table 4 in respect of which the variances do not meet the materiality threshold calculated below. Please also refer to Schools Energy Coalition IR #14 for further details on the job evaluation study referred to in the responses below. For accounts in respect of which the variances meet the materiality threshold, BPI has provided explanations following the materiality calculation.

Materiality calculation:

	2006 Board			
Distribution Expenses before taxes	Approved	2006 Actual	2007 Bridge	2008 Test
Operations	580,929	793,192	1,176,926	1,090,412
Maintenance	2,006,136	1,521,089	1,870,016	1,884,681
Billing & Collecting	905,817	1,900,231	2,145,847	2,302,509
Community Relations	446,549	326,422	190,140	139,091
Administration and General Expenses	3,437,561	1,984,087	2,634,367	2,783,384
Taxes other than income	162,777	9,635	12,459	12,298
Amortization Expense	2,476,213	2,556,007	2,781,345	3,027,657
Total Distribution Expenses	10,015,982	9,090,663	10,811,100	11,240,032
Materiality @ 0.2%	20,032	18,181	21,622	22,480

Account-related information:

Account	2006 Actual	2008 Test	Variance	%
5005 - Operation Supervision and Engineering	\$ 205,800	\$ 266,919	\$ 61,119	29.7%

Explanation:

Cost drivers include:

- Job evaluation study for all City of Brantford management staff completed during 2006 – the increase is reflective of the elevation of certain utility management positions. Increase in labour accounts for \$38,486 of variance.
- Change in indirect cost allocation contributed \$26,127 to variance.
- Decrease in other charges offset increase in cost drivers above.

Account	2006 Actual	2008 Test	Variance	%
5065 - Meter Expense	\$ 359,201	\$ 494,376	\$ 135,175	37.6%

Explanation:

Cost drivers include:

- Increases in standard fleet charges for vehicles used by Meter Technicians contributed \$15,925 to variance.
- Change in indirect cost allocation contributed \$9,764 to variance.
- MSP services moved from USoA 5310 contributed \$22,198 to variance.
- Absence of meter inventory writeoffs in 2008 that were present in 2006, \$36,143, serve to offset increases above.

Account	2006 Actual	2008 Test	Variance	%
5085 - Miscellaneous Distribution Expense	\$ 96,962	\$ 129,239	\$ 32,277	33.3%

Explanation:

Cost drivers include:

- Change in business unit work plans and priorities from year to year resulting in increase in labour and material costs of \$14,365.
- Increase in cost of supplies provided by 3rd party amounted to \$7,344.
- Radio license paid to the Receiver General increased by \$5,425.
- Change in indirect cost allocation contributed \$6,704 to variance.

Account	2006 Actual	2008 Test	Variance	%
5105 - Maintenance Supervision and Engineering	\$ 245,710	\$ 306,914	\$ 61,204	24.9%

Explanation:

Cost drivers include:

- Change in indirect cost allocation contributed \$62,950 to the variance. This increase was offset by a decrease in other charges.

Account	2006 Actual	2008 Test	Variance	%
5130 - Maintenance of Overhead Services	\$ 196,674	\$ 219,810	\$ 23,136	11.8%

Explanation:

Cost drivers include:

- Change in indirect cost allocation contributed \$50,561 to the variance. This increase was offset by a decrease in other charges.
- Supplies declined by \$13,769 and contracted services declined by \$5,413.

Account	2006 Actual	2008 Test	Variance	%
5135 - Overhead Distribution Lines and Feeders - Right of Way	\$ 328,908	\$ 364,402	\$ 35,494	10.8%

Explanation:

Cost drivers include:

- Change in business unit work plans and priorities from year to year resulting in increase in labour and material costs of \$6,654.
- Change in indirect cost allocation contributed \$5,271 to variance.
- Increase for tree trimming contract through the City of Brantford was \$23,569.
-

Account	2006 Actual	2008 Test	Variance	%
5150 - Maintenance of Underground Conductors and Devices	\$ 82,796	\$ 121,982	\$ 39,186	47.3%

Explanation:

Cost drivers include:

- Change in business unit work plans and priorities from year to year resulting in increase in labour and material costs of \$16,447.
- Change in indirect cost allocation contributed \$21,087 to variance.

Account	2006 Actual	2008 Test	Variance	%
5155 - Maintenance of Underground Service	\$ 171,741	\$ 222,899	\$ 51,158	29.8%

Explanation:

Cost drivers include:

- Change in business unit work plans and priorities from year to year resulting in increase in labour and material costs of \$14,661.
- Change in indirect cost allocation contributed \$43,943 to the variance.
- These increases were offset by a decrease in the allocation of previously unallocated labour-related charges; e.g. sick and vacation time.

Account	2006 Actual	2008 Test	Variance	%
5160 - Maintenance of Line Transformers	\$ 71,971	\$ 173,973	\$ 102,002	141.7%

Explanation:

Cost drivers include:

- Change in business unit work plans and priorities from year to year resulting in increase in labour and material costs of \$19,412.
- Change in indirect cost allocation contributed \$17,874 to variance.
- Supplies increased by \$65,345. Budget was under spent in 2006. Please refer to School Energy Coalition Interrogatory 17a) for more details.

Account	2006 Actual	2008 Test	Variance	%
5315 - Customer Billing	\$ 443,457	\$ 509,848	\$ 66,391	15.0%

Explanation:

Cost drivers include:

- Change in indirect cost allocation contributed \$65,626 to the variance.

Account	2006 Actual	2008 Test	Variance	%
5320 - Collecting	\$ 283,868	\$ 327,828	\$ 43,960	15.5%

Explanation:

Cost drivers include:

- Change in indirect cost allocation was \$43,960.

Account	2006 Actual	2008 Test	Variance	%
5335 - Bad Debt Expense	\$ 157,089	\$ 200,000	\$ 42,911	27.3%

Explanation:

Cost drivers include:

- 2006 Actual of \$157,089 includes a reduction of the allowance for doubtful accounts of \$240,000; actual write-offs net of recoveries were \$397,089. 2006 write offs included a significant industrial write-off \$137,270. Ignoring the change in the allowance and the one significant account, BPI's bad debts for 2006 were \$259,819. BPI is of the view that the 2008 Test year estimate of \$200,000 is reasonable based on historical trend excluding any significant one-time write offs.

Account	2006 Actual	2008 Test	Variance	%
5340 - Miscellaneous Customer Accounts Expense	\$ 503,980	\$ 709,340	\$ 205,360	40.7%

Explanation:

Cost drivers include:

- Reclassification of charges from Customer Service expected to increase by \$77,672 i.e. Customer Services costs that are distributed or reclassified among Accounts 5315, 5320, 5330, 5335 and 5340 annually in preparation of the USoA-based Trial Balance. Given this reclassification process, any variance not reclassified to Accounts 5315 to 5335 is booked to Account 5340, contributing to the year-over-year variance.
- Increase caused by a several factors that include salaries and benefits, postage, fleet charges and charges from other departments
- Change in indirect cost allocation contributed \$127,688 to the variance. This increase was offset by a decrease in other charges.

Account	2006 Actual	2008 Test	Variance	%
5605 - Executive Salaries and Expenses	\$ 377,446	\$ 429,070	\$ 51,624	13.7%

Explanation:

Cost drivers include:

- Job evaluation review for all City of Brantford and BPI management staff completed during 2006. 2006 Actual is lower than normal due to elimination of bonus that was typically accrued back to prior year. This contributed \$32,209 to variance.

Account	2006 Actual	2008 Test	Variance	%
5610 - Management Salaries and Expenses	\$ 598,244	\$ 723,218	\$ 124,974	20.9%

Explanation:

Cost drivers include:

- Increase in salaries and benefits contributed \$128,371 to the variance. The increase was due to the addition of staff combined with structured rate increases. The Job evaluation study for all City of Brantford management staff completed during 2006 contributed to \$60,057 of this variance.
- Decreases in the allocation of indirect costs in the amount of \$3,397 offset this increase.

Account	2006 Actual	2008 Test	Variance	%
5630 - Outside Services Employed	\$ 44,693	\$ 179,500	\$ 134,807	301.6%

Explanation:

Cost drivers include:

- 2008 budget includes allowance for contract staff and consulting costs in anticipation for changes required to implement International Financial Reporting Standards (IFRS) and completion of 2008 EDR application process.
- Reflects reclassification of \$49,500 in audit fees from accounting department indirect costs

Account	2006 Actual	2008 Test	Variance	%
5645 - Employee Pensions and Benefits	\$ 49,204	\$ 110,367	\$ 61,163	124.3%

Explanation:

Cost drivers include:

- Increase in pension costs for retirees, \$15,932, as well as estimated change in future employee benefit liability, \$45,231, supported by actuarial study in 2007.

Account	2006 Actual	2008 Test	Variance	%
5655 - Regulatory Expenses	\$ 88,064	\$ 215,000	\$ 126,936	144.1%

Explanation:

Cost drivers include:

- Change in business unit work plans and priorities from year to year. The 2006 Actual balance is anomalous in that no major regulatory projects requiring external contracted resources were completed in 2006.

Account	2006 Actual	2008 Test	Variance	%
5665 - Miscellaneous General Expenses	\$ (112,105)	\$ 187,617	\$ 299,722	-267.4%

Explanation:

Cost drivers include:

- Enhanced approach to accounting for fleet costs was implemented in 2007. The result of new approach changed mapping of accounts from 5655 to new fleet clearing account. This change contributed \$253,900 to variance.

- Estimated increase in cost allocation from parent company amounts to \$31,359.
- For further explanation regarding fleet accounting, refer to BPI's response to OEB Staff Question 1.4(b), above.

b) For the Account 5665 variance noted above, on page 10 of Schedule3, BPI has already provided the following explanation:

“For greater clarity and to substantiate the standard fleet charges used to recover actual fleet costs, the accounting treatment for these costs was substantially revised in 2007 through the creation of Fleet Business Unit, which collects all costs related to fleet. Those costs are subsequently charged to specific direct and capital costs through standard fleet charges. As a result, vehicle – related costs are not booked to Account 5665 beginning in 2007. The variance reflects the impacts of this change from 2006 to 2007”

If, as stated above, vehicle-related costs are not booked to Account 5665 beginning in 2007, please clarify why the amount charged to this account is increasing to the extent of \$284,723 for 2007 and provide a full explanation of the variance.

RESPONSE:

Please refer to BPI's response to School Energy Coalition Interrogatory 13 for further explanation.

The summary in School Energy Coalition Interrogatory 13 highlights on a comparative basis the accounts that relate to fleet costs. The large credit balance in the 2006 accounts represents the amount distributed using the standard charge out rates exceeding the actual direct costs. Under the previous approach no adjustments were made when charges determined using the standard rates deviated from the total actual cost. The increase reflected in 2007 is not the result of significant additional charges to this account but rather the result of removing the large credit balance in over distributed charges recorded in 2006 and allocating fleet depreciation expenses directly to the fleet account. The impact for 2007 and beyond reflects fully allocated fleet costs consistent with the Accounting Procedures Handbook –Article 340 direction that “Any residual balance remaining after regular distribution shall be cleared to the applicable plant and operating accounts by apportioning on a basis which will distribute the cost equitably.”

The summary below highlights on a comparative basis the accounts, which reflected the fleet costs, illustrating the impact of amounts no longer mapped to USoA 5655.

FLEET CLEARING BUSINESS UNIT	<u>2006</u> <u>ACTUAL*</u>	<u>2008 Test</u>	Impact on 5655
Fleet Home Account	(553,827)	(520,662) from 5655	<u>553,827</u>
Licenses	6,430	5,500 from 5655	(6,430)
Amort Exp - Vehicles	215,691	246,992 from 5705	
Insurance and Risk Mgmt - Vehicles		20,000	
Transit (fuel & repairs for vehicles)	176,849	175,000 from 5655	(176,849)
Works Dept (fuel & repairs for vehicles)	11,357	10,000 from 5655	(11,357)
Fleet Expenses Operations	59,314	63,173 from 5655	(59,314)
	<u>469,641</u>	<u>520,665</u>	<u>(253,950)</u>
Net Recovery deficit/(surplus)	(84,186)	3	299,877
Indirects	45,979	-	(45,979)
Net Recovery deficit/(surplus) after Indirects	<u>(38,207)</u>	<u>3</u>	<u>253,898</u>

* Fleet clearing business unit introduced in 2007; 2006 actuals presented for illustrative purposes only.

Fleet related accounts no longer mapped to 5665

Summary:

2006 Actual	(112,105)
Fleet accounts re-mapped	253,900
Change in remaining accounts (non-Fleet)	45,822
2008 Test	<u><u>187,617</u></u>

SHARED SERVICES

1.5 Ref: Exhibit 4/Tab 2/Schedule 4

On page 1 of this schedule, BPI discusses its shared services arrangements. Please provide an overview of these arrangements in the following format for each of the 2006 historical, 2007 bridge and 2008 test years:

- a) Total dollar amount of expenses paid to affiliates for services rendered and the percentage amount this represents of total expenses and a breakdown between the relevant services,

RESPONSE:

	2006 Actual	2007 Bridge	2008 Test
Total dollar amount of expenses paid to affiliates	\$ 6,418,335	\$ 7,357,083	\$ 7,552,918
Total expenses	<u>\$ 11,239,678</u>	<u>\$ 12,858,464</u>	<u>\$ 13,631,395</u>
Total paid as a % of total expenses	<u>57.10%</u>	<u>57.22%</u>	<u>55.41%</u>

Total amount of expenses paid to affiliates by relevant services (before allocation of indirect costs)

Operations	\$ 561,778 8.75%	\$ 791,804 10.76%	\$ 674,334 8.93%
Maintenance	\$ 736,567 11.48%	\$ 927,556 12.61%	\$ 880,512 11.66%
Billing and Collecting	\$ 154,214 2.40%	\$ 168,210 2.29%	\$ 178,848 2.37%
Community Relations	\$ 135,496 2.11%	\$ 98,675 1.34%	\$ 100,293 1.33%
Administrative and General	\$ 741,685 11.56%	\$ 952,388 12.95%	\$ 1,016,547 13.46%
Shared Services	\$ 4,088,595 63.70%	\$ 4,418,450 60.06%	\$ 4,702,384 62.26%

- b) Total dollar amount of revenue received from affiliates for services provided and the percentage amount this represents of total revenue and breakdown between the relevant services, and

RESPONSE:

Pole Rental Revenue charged to Retail Affiliate	2006 Actual	2007 Bridge	2008 Test
Total dollar amount of revenue from affiliate	\$ 30,491	\$ 29,815	\$ 30,709
Total revenue	\$ 15,685,480	\$ 16,226,838	\$ 18,059,328
Total received as a % of total revenue	<u>0.19%</u>	<u>0.18%</u>	<u>0.17%</u>

Total Other Operating Revenue	\$ 678,374	\$ 880,334	\$ 871,329
Proportion received from affiliate	4.49%	3.39%	3.52%

- c) Total dollar amount of expenses incurred related to the provision of services to affiliates and the percentage amount this represents of total expenses and a breakdown between the relevant services.

RESPONSE:

BPI charges its retail affiliate, Brantford Hydro Inc., the regulated rate of \$22.35 per pole attachment and does not separately track expenses that are specifically related to the pole rental service provided to its retail affiliate. The retail affiliate is treated in the same manner as any other party requiring pole attachments.

The retail affiliate is billed directly by the service provider, The City of Brantford, for any non-distribution expenses incurred.

1.6 Ref: Exhibit 4/Tab 2/Schedule 4

On page 1, BPI states that “it is undertaking a review of transfer pricing methodologies and intra-company cost allocations.”

a) Please describe the scope of this review and why it is being undertaken.

RESPONSE:

Background:

Brantford’s Energy Group of Companies is comprised of Brantford Energy Corporation, a holding company; BPI, the electricity distribution company; Brantford Hydro Inc., a retail company with three principle lines of business being water heater rentals, sentinel light rentals and fibre optic telecommunications services marketed under the brand name “NetOptiks”; and Brantford Generation Inc. Brantford Generation Inc. was incorporated in October 2007 for the purpose of developing electricity generation projects and is currently developing an electricity generation project utilizing methane gas from the local landfill site.

Currently, the City of Brantford provides a variety of services to Brantford’s Energy Group of Companies. Costs for those services are transferred to the Energy Group of Companies using the transfer pricing mechanisms described in Exhibit 4, Tab 2, Schedule 4, Pages 1 to 5. Subsequently, those costs are allocated among the group of companies using the cost allocators described in Exhibit 4, Tab 2, Schedule 4, Table 4.2.4-1, Page 6.

Scope of the review:

The purpose of the transfer pricing review is to ensure that transfer pricing mechanisms comply with the requirements of the OEB’s Affiliate Relationships Code for Transmitters and Generators and specifically Section 2.3 regarding transfer pricing.

The scope of the study comprises the following elements:

1. To identify cost-effective mechanisms to measure units of services delivered by the service provider against the levels of service defined in the services agreement;
2. To identify available sources of information to track delivery of services by units of service delivered and related costs or, where such information sources are not readily available, to identify cost-effective methods for tracking service delivery and related costs; and
3. To review mechanisms for allocating costs among the Energy Group of Companies to ensure that there is no cross-subsidization among the group of companies.

Why it is being undertaken:

The review is being performed pursuant to BPI’s obligation to ensure ongoing compliance with the Affiliate Relationships Code by performing periodic compliance reviews [section 2.7.1],

and to ensure compliance with the OEB's Affiliate Relationships Code and specifically Section 2.3 regarding transfer pricing.

As set out in the Summary to the Application at Exhibit 1, Tab 2, Schedule 1 and based on the OEB's Comparison of Ontario Electricity Distributors Costs [EB-2006-0268] updated with 2006 Data issued September 7, 2007, BPI's total operations, maintenance and administrative costs for 2006 are \$182.00 per customer and compare favourably with the average of \$191.00 per customer for its cohort group. Similarly, Brantford Power Inc.'s average operations maintenance and administrative costs for the period of 2002 to 2006 are \$188.00, again comparing favourably with the average of \$193.60 for its cohort group. However, BPI still believes that the transfer pricing review will be beneficial.

b) Please state when it is anticipated this review will be completed.

RESPONSE:

Preliminary planning work was undertaken in second quarter of 2007, but was suspended pending preparation of BPI's 2008 distribution rate Application.

It is anticipated that this review will be recommenced in June 2008 and will be completed by July 2009. While most work will be completed by the end of 2008, preliminary work undertaken in 2007 indicated that some services functions are cyclical in nature and will require data collection over a one-year period. Customer Services and Financial Services are examples of service activities that experience a one-year business cycle.

1.7 Ref: Exhibit 4/Tab 2/Schedule 4

On page 3 of this exhibit, cost allocators for “Property Management – Use and Maintenance of facilities” are stated as “actual square footage” for properties at 84 Market Street Square and 400 Grand River Avenue and “actual square footage occupied” for properties at 220 Colborne and 100 Wellington Square. Please clarify whether or not there is any difference between these two cost allocators and if so, explain the difference and why it occurred.

RESPONSE:

With reference to Exhibit 4 Tab 2 Schedule 4, Page 3, Lines 23 to 29 of the Application, BPI notes that costs allocators for Property Management costs were described as follows:

"Property management at 84 Market Street Square (*sic*) [Administration] and 400 Grand River Avenue [Service Centre and Vehicle Garage] based on actual square footage (*emphasis added*)

Property Management at 220 Colborne and 100 Wellington Square based on estimates of square footage occupied (*emphasis added*)"

Noting this clarification, the difference between the two cost allocators is discussed below.

The staff providing services to BPI at 84 Market Street, (the administrative offices), and 400 Grand River Avenue, (the service centre) are, with the exception of the CFO – Utilities and the Board Secretary, fully dedicated to BPI. The costs associated with those employees represent services purchased from the City of Brantford, and 100 percent of those employees’ time and activities are charged to BPI because those employees provide services directly to Brantford Power Inc., as opposed to being shared with the City or other companies within the Energy corporate family. The square footage occupied by those employees can therefore be defined. As a result, property management costs are allocated on the basis of actual square footage occupied.

The staff providing services to Brantford’s Energy group of companies, including BPI housed at 100 Wellington Square and 220 Colborne Street, are shared. Those staff may provide services to other companies in the Energy corporate family and/or the City. Because those costs are transferred to Brantford Power using cost allocators, the square footage of space occupied by those staff is estimated.

1.8 Ref: Exhibit 4/Tab 2/Schedule 4

On page 5, it is stated that “As the newest company within the Energy group of companies, Brantford Generation Inc. was incorporated in October 2007 and as the company is in its developmental stage, shared service costs have not been allocated to it in 2008.”

- a) Please state whether or not Brantford Power would agree that the non-allocation of shared service costs to Brantford Generation Inc. would mean that shared service costs associated with Brantford Generation Inc. would be over-recovered from Brantford Power in the three-year period until Brantford Power’s next cost of service application. If Brantford Power does not believe this to be the case, please state why.

RESPONSE:

BPI does not agree that the non-allocation of shared services costs to Brantford Generation Inc. would mean that the shared services costs associated with Brantford Generation Inc. would be over-recovered from BPI in the three-year period until BPI next cost of service application.

Starting in October 2005, Brantford Hydro Inc., the retail affiliate in Brantford’s Energy Group of Companies undertook the activity of examining the feasibility of an electricity generation facility utilizing methane gas from the City of Brantford’s landfill site. Staff and service resources allocated to Brantford Hydro Inc. were utilized to perform this developmental work and feasibility assessment as directed by the Brantford Hydro Inc. Board of Directors.

Subsequent to completing this preliminary development work, Brantford Generation Inc. was incorporated in October 2007 to undertake construction and implementation of the Mohawk Street methane gas electricity generation project. To October 2007, all costs associated with this project were borne by Brantford Hydro Inc. and resources allocated to that company. Staff and resources allocated to BPI were not utilized in the development of the landfill methane gas project.

Going forward into the construction and implementation phase of this project, staff and resources allocated to Brantford Hydro Inc. will continue implementation of this project. Subsequent to filing BPI’s rate Application and for the 2008 budget, costs previously charged to Brantford Hydro Inc. have been allocated between Brantford Hydro Inc. and Brantford Generation Inc.

- b) Please provide Brantford Power's views on whether or not the Board should be concerned about this potential subsidy and if not, why not. If Brantford Power believes the Board should have concerns in this area, please propose any potential remedies that would be acceptable to Brantford Power.

RESPONSE:

Because staff and resources allocated to Brantford Hydro Inc. have been utilized in the feasibility and developmental stages of the landfill methane gas generation project, and because starting in 2008, such resources and related costs have been split between Brantford Hydro Inc. and Brantford Generation Inc., there is no potential subsidy by BPI in these circumstances.

BPI notes that any costs related to this project such as a connection impact assessment will be charged to Brantford Generation Inc. in the same way that costs would be charged to another third-party generator.

1.9 Ref: Exhibit 4/Tab 2/Schedule 4

On page 5, a reference is made to services being shared among “the Energy group of companies.” Please state which group of companies is being referred to and whether this group also includes the Corporation of the City of Brantford.

RESPONSE:

The group of companies being referred to consists of:

1. Brantford Energy Corporation, the holding company, ;
2. Brantford Power Inc. the electricity distribution company, ; and
3. Brantford Hydro Inc., the retail company.

The group of companies referred to on Page 5 does not include the Corporation of the City of Brantford.

As discussed in response to OEB Staff Interrogatory 1.8 above, Brantford Hydro Inc. was responsible for the development of an electricity generation project, which resulted in the incorporation of Brantford Generation Inc. in October 2007. All costs related to this project were borne by Brantford Hydro Inc. Subsequent to filing the BPI 2008 rate Application and for the 2008 budget, those costs were allocated between Brantford Hydro Inc. and Brantford Generation Inc. as the landfill methane gas project moves into its construction, implementation and operational phases. No portion of the generation-related costs is now being allocated to BPI, nor will any portion be allocated to BPI.

1.10 Ref: exhibit 4/Tab 2/Schedule 4

Table 4.2.4-1 provides cost allocation percentages for intra-company cost allocations.

- a) Please state which entities are included under the heading “Energy”

RESPONSE:

The entity under the heading “Energy” is Brantford Energy Corporation, the holding company.

- b) The description of some of the cost allocators in the Table does not appear to be consistent with those outlined in the preceding pages of the exhibit. For instance, Records Management is described as allocated based on “% of Total Assets” in the Table, but “cubic foot volume of corporate records in storage as a percentage of overall record holdings” on page 1 of the exhibit. Insurance and Risk Management Services similarly is described as “% of total Assets” in the table, but “Administrative service costs allocated on basis of a percentage of the value of insurance premiums” on page 2 of the Exhibit. Please review for each of the shared services the consistency of the definitions between the text of the Exhibit and the Table. If Brantford Power believes the definitions are consistent, please explain why. If not, please make any necessary corrections and explain the rationale.

RESPONSE:

With respect to shared services costs, most services are shared between the City of Brantford’s municipal activities and Brantford’s Energy Group of Companies. These services include:

- Records management
- General Mail Services
- Insurance and Risk Management Services
- Customer Services
- Telephone Services
- General Financial Services
- Acquisition and disposal of real property
- Property Management services, specifically at 100 Wellington Square and 220 Colborne Street
- Legal Services
- Human Resources
- IT Services – Network Services
- Senior Management Services
- Vehicle Maintenance, and
- Forestry.

Other services are shared among the Energy Group of companies and include:

- Meeting Management Services
- Utilities Accounting Services including the Chief Financial Officer
- Inventory and Stores except for supervisory costs, which are shared with other municipal activities
- Property Management at 84 Market Street and 400 Grand River Avenue, and
- IT Services – Energy Specific Services.

Where services are shared, the costs are transferred to the Energy group of companies using the cost allocators described in Exhibit 4, Tab 2, Schedule 4, Pages 1 to 5. Those costs are then allocated among the members of the Energy group of companies using the allocators set out in Exhibit 4, Tab 2, Schedule 4, Table 4.2.4-1. The cost allocators used to allocate costs among the corporate family are different from those used to allocate costs to the corporate family.

- c) Please provide Brantford Power's position on whether or not the allocation outlined in this Table, which sees 80% of overall costs allocated to Brantford Power is reasonable and, if so, why.

RESPONSE:

Please note that it is more accurately 89% of costs that are allocated to BPI. BPI is of the view that the allocation of overall costs to BPI is reasonable. As set out in the Summary to the Application at Exhibit 1 Tab 2 Schedule 1 and based on the Ontario Energy Board's Comparison of Ontario Electricity Distributors Costs [EB-2006-0268] updated with 2006 Data issued September 7, 2007, BPI's total operations, maintenance and administrative costs for 2006 are \$182.00 comparing favourably with the average of \$191.00 for its cohort group. Similarly, BPI's average operations maintenance and administrative costs for the period of 2002 to 2006 are \$188.00 again comparing favourably with the average of \$193.60 for its cohort group. As noted in the Application, BPI commenced a Transfer Pricing Study in 2007 and this study will continue in 2008. This study will allow BPI to identify cost drivers more accurately. Brantford Power Inc. notes that a possible outcome of this study is that higher costs may be allocated to Brantford Power Inc.

EMPLOYEE COMPENSATION

1.11 Ref: Exhibit 4/Tab 2/Schedule 3

On page 6, Brantford Power provides a breakdown of its General and Administrative Salary expenses.

- a) For non-executive employees, please state how costs charged to Brantford Power are determined and what types of costs are included, i.e. salaries, pension, benefits, incentives, etc.

RESPONSE:

Direct Purchase of Services:

Direct services comprising Operations and Maintenance, Engineering, Metering and Settlement, Regulatory and Administration are, subject to the Services Agreement with the City of Brantford, charged on an actual cost basis including salaries and wages, pensions and benefits and overtime, with a mark-up to approximate market conditions.

Shared services comprise service fees determined using cost allocators described in Exhibit 4, Tab 2, Schedule 4, Pages 1 to 5 and Exhibit 4, Tab 2, Schedule 4, Table 4.2.4-1. Non-executive staffing costs comprise salaries and wages, pension and benefits and overtime, with a mark-up to approximate market conditions. There are no incentive costs included in compensation components of non-executive service fees.

- b) For each employee category: Executive, Management, Non-Unionized and Unionized, please state the aggregate costs for Brantford Power in 2006, including Historical Board Approved and Actual, 2007 and 2008.

RESPONSE:

Please see BPI's response to School Energy Coalition Interrogatory 17(b). Shared services costs are transferred to BPI in the form of service fees in accordance with the Services Agreement with the City of Brantford. These service fees are derived by applying the cost allocators set out in Exhibit 4, Tab 2, Schedule 4, Pages 1 to 5 in order to allocate costs to the Energy group of companies. Those service fees are subsequently allocated among the Energy group of companies using the cost allocators set out in Exhibit 4, Tab 2, Schedule 4, Table 4.2.4-1 Page 6. As a result, compensation data presented in BPI's response to School Energy Coalition Interrogatory 17(b) are based on estimates of compensation costs.

1.12 Ref: Exhibit 4/ Tab 2/Schedule 3

Please provide a breakdown of the total number of employees who work for, or provide services to Brantford Power, for each employee category: Executive, Management, Non Unionized and Unionized, for the 2006 Board approved year, 2006 actual year, 2007 bridge, and 2008 test year.

RESPONSE:

Costs are transferred from the service provider to Brantford Power Inc. in the form of service fees. As a result, the breakdown of total number of employees who work for or provide services to Brantford Power Inc. by employee is an estimate derived from applying the cost allocators described in Exhibit 4, Tab 2, Schedule 4, Pages 1 to 5 and Table 4.2.4-1 on page 6 of the same Schedule.

Employee Classification	2006 Board-approved	2006 Actual	2007 Bridge	2008 Test
Executive	1.36	1.18	1.18	1.18
Management	12.78	13.6	13.3	13.82
Non-Union	7.24	8.24	10.24	11.24
Union	41.61	44.43	45.63	45.63
Total	62.98	67.44	70.32	71.7

1.13 Ref: Exhibit 4

Please provide a cost breakdown for actual and forecast, where applicable, for the 2006 Board approved, 2006 actual, 2007 bridge year, and 2008 test year regarding the following regulatory costs and present it in the following table format:

Regulatory Cost Category	Ongoing or one-time costs	2006 Board-Approved	2006 Actual	2007 as of December 07	% change in 2007 vs. 2006	2008 Forecast	% change in 2008 vs. 2007
OEB Annual Assessment	Ongoing		\$ 70,470.00	\$ 92,704.00	24%	\$ 100,000.00	7%
OEB Hearing Assessment [applicant initiated]	One-time			\$ 7,242.23	100%	\$ 10,000.00	28%
OEB Section 30 costs [OEB Initiated]	Ongoing			\$ 1,788.07	100%	\$ 5,000.00	64%
Expert witness cost for regulatory matters	One-time					\$ 10,000.00	100%
Legal costs for regulatory matters	One-time	\$71,857.67	\$ 9,631.89	\$ 92,751.70	90%	\$ 45,000.00	-132%
Consultant costs for regulatory matters	One-time	\$15,640.61	\$ 7,366.76	\$ 58,764.83	87%	\$ 50,000.00	-31%
Operating expenses associated with staff resources allocated to regulatory matters	Ongoing	\$ 101,876.55	\$ 109,191.25	\$ 158,769.77	31%	\$ 274,092.75	42%
Operating expenses associated with other resources allocated to regulatory matters [identify]	Ongoing			\$ 47,981.00	100%	\$ 5,000.00	-860%
Other Regulatory agency fees or assessments [Electrical Safety Association]	Ongoing	\$ 13,712.00	\$ 13,714.00	\$ 14,524.00	6%	\$ 20,000.00	27%
Any other costs for regulatory matters [please define]	One-time	\$ 9,068.91	\$ 276.16	\$ -		\$ -	
Total		\$ 212,155.74	\$ 210,650.06	\$ 474,525.60	56%	\$ 509,092.75	7%

- a) Under “Ongoing or One-time Cost”, please identify and state if any of the regulatory cost is “One-time Cost” and not expected to be incurred by the applicant during the impending two year period when the applicant is subject to 3rd Generation IRM process or it is “Ongoing Cost” and will continue throughout the 3rd Generation of IRM process.
- b) Please state the Utility’s proposal on how it intends to recover the “One-time” costs as a part of its 2008 rate application.

RESPONSE: a & b

External costs for one-time regulatory projects undertaken in 2007 are described in Table 1.13-1, below.

**TABLE 1.13-1
 2007 ONE-TIME REGULATORY EXTERNAL COSTS**

PROJECT	COST	ONGOING vs. ONE-TIME
Cost Allocation Information Filing	\$8,284.00	One-time; Note: A 2009 cost allocation study to review usage and cost by class will be preparatory to 2011 cost of service rate application
2007 Rate application. Written hearing and interrogatories	\$37,627.36	One-time;
2008 Rate application. Application filing	\$96,073.71	Comprises only costs pertaining to the rate application with costs relating to written hearing, interrogatories and final submissions accruing in 2008; Note also, costs pertaining to 2011 cost of service rate application will occur in 2010
2006 Conservation and Demand Management Total Resource Cost analysis	\$9,540.00	One-time
Transfer Pricing Study	\$7,233.67	Note that the Transfer Pricing Study commenced in 2007 but was deferred to 2008 pending preparation of the 2008 cost of service rate application. Work will be substantially completed in 2008 with some follow-up work in 2009
Total	\$158,758.76	

The regulatory program for the term of third generation incentive regulation from 2008 to 2010 includes the following projects that will require external regulatory resources, described in Table 1.13-2 below:

**TABLE 1.13-2
 3rd GENERATION INCENTIVE REGULATION REGULATORY PROJECTS**

2008 REGULATORY PROJECTS	ESTIMATED COST
2008 rate application. Written hearing and interrogatories	\$60,000.00
Transfer Pricing Study	\$55,000.00

2009 REGULATORY PROJECTS	ESTIMATED COST
2009 Smart Meter Rate Adder rate application	\$10,000.00
Transfer Pricing Study	\$10,000.00
Cost Allocation Study (preparatory to 2011 rate application)	\$95,000.00

2010 REGULATORY PROJECTS	ESTIMATED COST
2011 Cost of Service rate application	\$95,000.00
Other unspecified projects	\$20,000.00

The 2008 rate Application includes regulatory staffing in the amount of \$274,092.75 and external regulatory costs for legal and consultant services in the amount of \$115,000.00. The 2008 forecast in internal regulatory staffing costs comprise an increase of \$115,322.98 or 42%. This increase results from:

- Annual economic adjustments, annual step movements through the salary grid,
- The annualization of one .5 FTE employee who was hired in May 2007; and
- Proposed new regulatory analyst position, as discussed in greater detail in the response to SEC IR 17.

This increase is offset by a reduction in 2008 over 2007 in the amount of \$42,981.00 for other resources allocated to regulatory matters; specifically, this was a contract position engaged in 2007 to assist with the preparation of the 2008 rate application. With this expenditure offset, the incremental increase for ongoing regulatory staffing expenses is \$72,341.98 or 26 per cent.

The 2008 forecast for external regulatory costs comprise a reduction of (\$43,758.76) or (28%) in 2008 costs over 2007. That reduction recognizes one-time costs in 2007 of BPI's 2007 rate application written hearing and interrogatories and 2006 CDM TRC analysis and anticipates reductions in external costs related to rate applications as internal staff become more familiar with the forward test year cost of service process. However, some of those one-time costs will be replaced with costs for new regulatory projects or completion of current regulatory projects

during the term of 3rd Generation Incentive Regulation, as described in Table 1.13-2, above. The trend line for external regulatory costs of \$115,000.00, adjusted in 2007 to reflect unusual regulatory costs in that year, is consistent with prior years and has been included in the 2008 forecast. BPI submits that maintaining this amount in its revenue requirement in 2008 and through the impending IRM period will enable BPI to address its 2008 external regulatory costs and those projected for the IRM period.

BPI notes that these are the projects that have been determined at this time. BPI also endeavors to do compliance reviews with respect to OEB Codes on a 3-year cycle, and these reviews will likely also require external contracted resources.

2 REVENUE OFFSETS AND SPECIFIC SERVICE CHARGES

2.1 Ref: Exhibit 3/Tab 3/Schedule 2 page 1

Account 4235 – Miscellaneous Service Revenue states as follows:

“Commencing in June 2006, the Collection of Accounts charge has been applied when collection activities leading to disconnection commence with the hand delivery of a disconnection notice”.

Please provide the rationale for why this change was made in June 2006.

RESPONSE:

BPI began charging this fee earlier in the collection process in June 2006, to align its practices with the industry. Prior to June 2006, the collection fee was assessed only if funds were collected at the customer’s door at the time of attendance by BPI for the purpose of disconnection. The fee would not be charged if the arrears were paid after the attendance but before disconnection. Clarification was obtained from the OEB as to when the charge could be assessed. OEB staff confirmed that the payment did not have to be collected at the door - rather, the fee could be assessed if the collection activity resulted in payment being made, even if the payment were made after the attendance.

To summarize, the collection of account charge is added to the customer’s arrears at the time of delivery of the disconnection notice. The disconnection notice gives the customer 7 days to pay the outstanding bill (including the collection of account charge). If the customer pays the outstanding bill (including the collection of account charge) prior to the disconnection of the customer’s service, then there will be no disconnection. If the customer does not pay the arrears and the collection of account charge, then the electricity is disconnected. Upon disconnection, the collection of account charge is no longer assessed against the customer, but the customer would be charged for reconnection in accordance with BPI’s Schedule of Rates and Charges.

Applying the collection of account service charge at all times during the disconnection notice period, from the delivery of the disconnection notice until immediately prior to disconnection, rather than only if payment is received at the initial visit to deliver the disconnection notice, helps BPI recover the additional costs associated with the delivery of the notice from those customers that cause these additional costs.

2.2 Ref: Exhibit 3/Tab 3/Schedule 2

The following two tables are taken from the evidence on interest and dividend income.

Table 6

Account	2006 Actual	2007 Bridge	Variance
4405, Interest and Dividend Income	\$479,721.00	\$283,954.00	(\$195,767.00)

Table 7

Account	2007 Bridge	2008 Test	Variance
4405, Interest and Dividend Income	\$283,954.00	\$439,000.00	\$155,046.00

For each of the indicated years:

- a) Please provide the principal balance on which the interest has been calculated.
- b) Please separate the interest on deferral and variance accounts from other sources of interest.
- c) Please provide the sources of the interest income, specifically stating whether any of this interest relates to regulatory assets.
- d) Please provide calculations and assumptions to show how the variance of \$155, 046.00 for the 2008 Test versus the 2007 Bridge year results from a projected increase in interest rates, as stated in the evidence.

RESPONSE: a-d

The following table has been provided to identify sources of interest and dividend income that was included in USoA 4405 Interest and Dividend Income.

	2006 Actual	2007 Bridge	2008 Test
Interest on AR (Services)	1,616	1,954	2,000
Bank Interest	295,544	282,000	437,000
Interest on Deferral and Variance Accounts	182,560	-	-
	479,720	283,954	439,000

a) Interest on AR Services (ie Billable Work Orders)

Represents late payment interest, 1% per month, charged on outstanding balances.
 System generated in 2006; Estimates in 2007 Bridge and 2008 Test based on actuals.

Bank Interest	2006 Actual	2007 Bridge	2008 Test
Interest Rate on Surplus Cash	4.25%	4.25%	4.88%
Total Cash on Hand at Year End	7,080,685	7,464,000	11,148,440
Average Cash Balance	7,330,804	7,272,342	9,306,220
Bank Interest Calculated	311,559	309,075	454,144
Bank Interest per above	295,544	282,000	437,000
difference	(16,015)	(27,075)	(17,144)

Interest on Deferral and Variance Accounts

Calculated on net debit balance in 2006; 2007 Bridge and 2008 Test
Deferral and Variance Accounts moved from a net debit balance to a net credit balance.
Interest expense mapped to USoA 6035 in those years.

Interest is calculated and booked monthly as prescribed by OEB.

- b) Refer to Table above.
- c) Source of interest detailed in Table above.
- d) Primary contributor to interest income is bank interest paid on cash balances.
Increase due to both higher projected cash balances on hand and higher interest rate as presented in response to a) above under heading "**Bank Interest**"

3 RATE BASE

3.1 Ref: Exhibit(s) General

- a) Please provide Brantford Power's Code of Business Conduct.

RESPONSE:

At the time of this filing BPI does not have a formalized "Code of Business Conduct" document. BPI is very aware of and complies with all applicable laws, regulatory rules, codes, guidelines and regulations associated with owning and operating an regulated electrical distribution system in Ontario.

- b) For the years 2002 to 2008 inclusive, please provide a table listing the following information (actual dollars where available, or expected, planned or projected dollars, or % where indicated):
- i. Net income
 - ii. Actual Return on the equity portion of the rate base (%);
 - iii. Allowed Return on the Equity portion of the rate base (%);
 - iv. Retained Earnings;
 - v. Dividends to Shareholders;
 - vi. Sustainment Capital Expenditures excluding smart meters;
 - vii. Development Capital Expenditures excluding smart meters;
 - viii. Operations Capital Expenditures;
 - ix. Smart meters Capital Expenditures;
 - x. Capital Expenditures (identify);
 - xi. Total Capital Expenditures including and excluding
 - xii. Depreciation;
 - xiii. Construction Work in Progress
 - xiv. Number of customer additions by class
 - xv. Rate Base.

RESPONSE:

Please refer to Attachment B for full response.

3.2 Ref: Exhibit 2/Tab 1/Schedule 2

With reference to page 1 of this Exhibit, the Rate Base Summary Table and the associated detailed tables:

- a) For Year 2006: Board-Approved Gross Assets versus Actuals, please provide a table reconciling the cost differences and the reasons for the difference between the Board-Approved Asset Value at Cost totaling \$52,875,117 versus an actual of \$64,875,909.

RESPONSE:

\$64,875,909 was the average of the opening and closing balances for Gross Assets in 2006, used in order to calculate Rate Base. As staff is aware, the 2006 Board-Approved rate base was established using 2004 data subject to a limited number of adjustments, and there have been two years of additions to BPI's assets in that time. The following table provides the requested reconciliation.

VARIANCE ANALYSIS

2006 Board Approved	52,875,121
2006 Actual	67,740,360
Variance	14,865,240
 Variance explanation	
Add:	
2005 Additions - Net	11,640,194
2006 Additions - Net	5,728,911
 Deduct:	
CDM Assets included in 2006 Board Approved	(548,248)
2006 EDR Adjustments - excluding CDM	(1,955,618)
	14,865,240

- b) For Year 2006: Board-Approved accumulated Depreciation versus Actuals, please provide a table reconciling the differences and the reasons for the difference between a Board-Approved Depreciation amounts of \$7,319,594 against an actual of \$12,626,782.

RESPONSE:

Please note, \$12,626,782 was the average used for the purpose of calculating rate base.

VARIANCE ANALYSIS

2006 Board Approved	(7,319,534)
2006 Actual	(13,924,169)
Variance	<u>(6,604,635)</u>

Variance explanation

Add:	
2005 Additions - Net	(2,497,700)
2006 Additions - Net	(2,594,775)
Deduct:	
2006 EDR Adjustments - excluding CDM	(1,512,160)
	<u>(6,604,635)</u>

3.3 Ref: Exhibit 2

- a) For the years 2002 to 2006 inclusive, please complete the following table including actual CAPEX dollars and % where indicated. Please identify the cost drivers, as indicated in the table. Examples of cost drivers are: replacement of aging or low capacity power lines, system expansions, etc. please identify the type and amount of any one-time unusual expenditure that may have occurred in any particular year and caused a change outside the given threshold, as provided in the table. Please exclude any smart meters from the dollar amount for the capital expenditure figures used in the table.

RESPONSE:

Table 8

CAPEX per Audited FS Cash Flow Statement where applicable

A	B	\$ Change (A-B)	% Change (\$Change/B)	Cost Drivers for the change if the change is either less than zero or more than 10%
2003	2002			
2,484,370	2,098,740	385,630.00	18%	Increased System Expansion Activity
2004	2003			
2,929,226	2,484,370	444,856.00	18%	Increased System Expansion Activity
2005	2004			
11,253,858	2,929,226	8,324,632.00	284%	New Powerline MTS - \$5.2 Million; Feeders from New Powerline MTS - 0.6 Million; Mayfair I Conversion from 4 to 27 kV - \$1.7 Million; Increased System Expansion Activity
2006 Actual	2005			
5,905,838	11,253,858	-5,348,020.00	-48%	Minus TS - \$5.2 Million
2006 Actual	2006 Board Approved			
5,905,838	4,860,810	1,045,028	21%	2006 Board Approved was based on 2004 Actuals. 2004 actuals were low because rates were frozen
2007 Bridge	2006 Actual			
5,777,604	5,905,838	-128,234.00	-2%	No Wholesale Metering Activity in 2007 compared to 2006 - minus 0.2 Million
2008 Test	2007 Bridge			
5,311,103	5,777,604	-466,501.00	-8%	Conversion project scope reduced compared with previous year - minus 0.4 Million

- b) On page 11 of Exhibit 2/Tab 2/Schedule 1, Account 1835 – Overhead Conductors and Devices – Opening Balance Net Book Value is shown as \$14,085,803 for 2006 versus \$5,407,610 for 2007. Please provide an explanation for this change, as well as any associated changes that may have been made elsewhere in the rate base.

RESPONSE:

Balances in account 1835 have been updated. A new Continuity Statement has been produced by BPI and replaces Exhibit 2, Tab 2, Schedule 1 of the Application. to the NEW Continuity Statement accompanies these responses as Attachment C.

- c) Please provide similar explanations for the changes in net book value for accounts 1840 and 1845 as shown on pages 3 and 4 of the same Schedule between the 2006 actuals and 2007 bridge year.

RESPONSE:

Balances in account 1840 and 1845 have been updated. As noted above in response to Question 3.3(b) a new Continuity Statement, which accompanies these responses as Attachment C, has been produced by BPI and replaces Exhibit 2, Tab 2, Schedule 1 of the Application.

3.4 Ref: Exhibit 2/Tab 3

This exhibit is entitled “Capital Budget by Project.” In regards to carryover projects and their costs:

- a) Please identify carryover projects where applicable, for the 2006 actual, 2007 bridge year, and 2008 test year. Please provide the information on these carryover projects, on an individual basis, i.e., one project at a time, including the dollar amount carried over from one year to another, and present it in the format outlined in the following Table 9.

Table 9

Type of Carryover Projects (e.g. power line replacements, pole replacements, smart meters, etc.)	\$ Carryover from 2005 to 2006	% Carryover from 2005 to 2006 to total 2006 Capital expenditure	\$ Carryover from 2006 to 2007	% Carryover from 2006 to 2007 to total 2007 Capital Expenditure	\$ Carryover from 2007 to 2008	% Carryover from 2007 to 2008 to total 2008 Capital Expenditure
1.						
2.						
3.						
4.						
5.						

RESPONSE:

BPI does not have any carryover projects and funds are not carried over from year to year for projects.

- b) Please provide an explanation for each project as to why the project was carried over, or is expected to be carried over from one year to another and present it on Table 10 below. Please specify if the project is one-time or an ongoing project.

Table 10

Type of Carryover Project (e.g. Underground cable replacement, smart meters, etc.)	One-time or ongoing project?	Reasons for the Carryover
1.		
2.		
3.		
4.		
5.		
6.		

RESPONSE:

N/A

- c) Please provide Brantford Power's most recent long term Capital Project or Asset Management Plan or equivalent which Brantford Power may be using for long term capital planning.

RESPONSE:

Please refer to Attachment D for BPI's Capital Project Plan.

- d) Please indicate if Brantford Power has utilized any asset condition study in developing its asset management plan. Please file the study, if any, with the Board.

RESPONSE:

BPI currently does not have an Asset Management Plan. BPI notes that in its 2006, 2007 and 2008 capital programs, it has included the following projected costs to complete installation work on its SCADA [Supervisory Control and Data Acquisition] system:

2006	\$105,991.24
2007	\$190,000.00
2008	\$190,000.00.

Additionally, BPI has included a projected cost of \$220,000.00 in its 2008 capital program to replace and upgrade its AM/FM GIS system. [Reference: Exhibit 2 Tab 3 Schedule 1]. As discussed in response to SEC IR 16(b), BPI has budgeted for a new position, an IT Project Coordinator, to undertake, among other activities, the developmental and systems-related work to roll-out the new AM/FM and GIS System. Completion of the SCADA and AM/FM and GIS systems are necessary building blocks to developing an asset management plan.

- e) With reference to page 28 of this Exhibit, "New Subdivisions & townhomes," please provide:
- i. The economic evaluation calculation for the aggregate of these expansion projects that total \$1,067,023;

RESPONSE:

		2008 Test	
		#	\$
New Subdivisions	# Lots x \$2,400	300	720,000
Townhomes	# Townhomes x \$2,100	100	210,000
			930,000
Allocation of Indirects			137,023
			1,067,023

The \$ per Lot/Townhome figures represent the total/gross estimated cost to service.

- ii. The Profitability Index (PI) and the total capital contributions contained within the \$1,067,023;and

RESPONSE:

No PI & Capital Contributions/Recoveries are contained within this amount. There is no Profitability Index (PI) included within the \$1,067,023. The electricity sector's economic evaluation model does not include a Profitability Index. The amount of \$1,067,023 does not include any capital contributions. Capital contributions are budgeted in the Contributions and Grants - Credit (OEB USoA account 1995).

- iii. As to whether or not the capital contributions have already been paid to Brantford Power and if not, when such payments is expected.

RESPONSE:

No payments have yet been received in respect of these projects. Typically, the developer pays the majority of the costs initially, and once the project has been energized, BPI reimburses the developer for all but capital contribution net of any costs paid by BPI.

- f) With reference to page 31 of this Exhibit, “Rebuild of existing Lines and Equipment, “please provide the following information on service reliability indicators recorded and used by Brantford Power:
- i. A listing of all the Service Reliability Indicators maintained and used, and their actual values for each of the years 2002 through 2007;

RESPONSE:

SERVICE RELIABILITY INDICES - 2007

SAIDI - System Average Interruption Duration Index

Time Period	Total Customer Hours of Interruptions	Total Customers Served	SAIDI
January	2946.13333	35000	0.08418
February	674.91667	35000	0.01928
March	4919.3833	36000	0.13665
April	3000	36000	0.08333
May	10110.43333	36000	0.28085
June	2611.03333	36000	0.07253
July	11557.31667	36000	0.32104
August	247.03333	36000	0.00686
September	740.35	36000	0.02057
October	3409.28333	36000	0.09470
November	2277.38333	36000	0.06326
December	574.91667	36000	0.01597

CAIDI - Customer Average Interruption Duration Index

Month	Total Customer Hours of Interruptions	Total Customer Interruptions	CAIDI
January	2946.13333	5741	0.51317
February	674.91667	242	2.78891

March	4919.38333	4651	1.05770
April	3000	3000	1.00000
May	10110.43333	6212	1.62756
June	2611.03333	9841	0.26532
July	11557.31667	9208	1.25514
August	247.03333	218	1.13318
September	740.35	195	3.79667
October	3409.28333	1830	1.86300
November	2277.38333	1950	1.16789
December	574.91667	1637	0.35120

SAIFI - System Average Interruption Frequency Index

Month	Total Customer Interruptions	Total Customers Served	SAIFI
January	5741	35000	0.16403
February	242	35000	0.00691
March	4651	36000	0.12919
April	3000	36000	0.08333
May	6212	36000	0.17256
June	9841	36000	0.27336
July	9208	36000	0.25578
August	218	36000	0.00606
September	195	36000	0.00542
October	1830	36000	0.05083
November	1950	36000	0.05417
December	1637	36000	0.04547

SERVICE RELIABILITY INDICES - 2006

SAIDI - System Average Interruption Duration Index

Time Period	Total Customer Hours of Interruptions	Total Customers Served	SAIDI
January	1440.98333	35000	0.04117
February	882.58333	35000	0.02522
March	1039.21667	35000	0.02969
April	2767.1333	35000	0.07906
May	1031.1500	35000	0.02946
June	2363.76667	35000	0.06754
July	3561.71667	35000	0.10176
August	6248.73333	35000	0.17854
September	2138.36667	35000	0.06110

October	4979.16667	35000	0.14226
November	7628.66667	35000	0.21796
December	2602.46667	35000	0.07436
Total	36683.95		1.04811

CAIDI - Customer Average Interruption Duration Index

Month	Total Customer Hours of Interruptions	Total Customer Interruptions	CAIDI
January	1440.98333	906	1.59049
February	882.58333	560	1.57604
March	1039.21667	3037	0.34219
April	2767.1333	5499	0.50321
May	1031.1500	615	1.67667
June	2363.76667	1913	1.23563
July	3561.71667	2720	1.30945
August	6248.73333	11679	0.53504
September	2138.36667	1970	1.08547
October	4979.16667	6915	0.72005
November	7628.66667	12291	0.62067
December	2602.46667	5951	0.43732
Total	36683.95	54,056	11.63222

SAIFI - System Average Interruption Frequency Index

Month	Total Customer Interruptions	Total Customers Served	SAIFI
January	906	35000	0.02589
February	560	35000	0.01600
March	3037	35000	0.08677
April	5499	35000	0.15711
May	615	35000	0.01757
June	1913	35000	0.05466
July	2720	35000	0.07771
August	11679	35000	0.33369
September	1970	35000	0.05629
October	6915	35000	0.19757
November	12291	35000	0.35117
December	5951	35000	0.17003

Total **54,056** **1.54446**

SERVICE RELIABILITY INDICES - 2005

SAIDI – System Average Interruption Duration Index

Time Period	Total Customer Hours of Interruptions	Total Customers Served	SAIDI
January	1950.5	33000	0.05911
February	348.25	33000	0.01055
March	4094.5	33000	0.12408
April	2228.18333	33000	0.06752
May	1785.4332	33000	0.05410
June	5211.85	33000	0.15793
July	9438.31667	35000	0.26967
August	2600.68333	35000	0.07431
September	13410.38333	35000	0.38315
October	1211.9	35000	0.03463
November	5050.95	35000	0.14431
December	57.41667	35000	0.00164
Total	47388.37		1.38100

CAIDI - Customer Average Interruption Duration Index

Month	Total Customer Hours of Interruptions	Total Customer Interruptions	CAIDI
January	1950.5	2811	0.69388
February	348.25	5357	0.06501
March	4094.5	2954	1.38609
April	2228.18333	5556	0.40104
May	1785.4332	5883	0.30349
June	5211.85	5786	0.90077
July	9438.31667	7235	1.30454
August	2600.68333	10947	0.23757
September	13410.38333	8644	1.55141
October	1211.9	5456	0.22212

November	5050.95	9481	0.53274
December	57.41667	3026	0.01897
Total	47388.37	73,136	7.61763

SAIFI - System Average Interruption Frequency Index

Month	Total Customer Interruptions	Total Customers Served	SAIFI
January	2811	33000	0.08518
February	5357	33000	0.16233
March	2954	33000	0.08952
April	5556	33000	0.16836
May	5883	33000	0.17827
June	5786	33000	0.17533
July	7235	35000	0.20671
August	10947	35000	0.31277
September	8644	35000	0.24697
October	5456	35000	0.15589
November	9481	35000	0.27089
December	3026	35000	0.08646
Total	73,136		2.13869

SERVICE RELIABILITY INDICES - 2004

SAIDI – System Average Interruption Duration Index

Time Period	Total Customer Hours of Interruptions	Total Customers Served	SAIDI
January	1152.46667	33000	0.03492
February	2210.86667	33000	0.06700
March	2459.41667	33000	0.07453
April	2385.65	33000	0.07229
May	2163.1500	33000	0.06555
June	1762.6	33000	0.05341
July	8518.1333	33000	0.25813
August	135.03333	33000	0.00409
September	552.75	33000	0.01675

October	550	33000	0.01667
November	412.31667	33000	0.01249
December	1197.8	33000	0.03630
Total	23500.18		0.71213

CAIDI - Customer Average Interruption Duration Index

Month	Total Customer Hours of Interruptions	Total Customer Interruptions	CAIDI
January	1152.46667	832	1.38518
February	2210.86667	3139	0.70432
March	2459.41667	2900	0.84807
April	2385.65	5334	0.44725
May	2163.1500	5335	0.40546
June	1762.6	3066	0.57489
July	8518.1333	16909	0.50376
August	135.03333	74	1.82477
September	552.75	914	0.60476
October	550	902	0.60976
November	412.31667	2713	0.15198
December	1197.8	5329	0.22477
Total	23500.18	47,447	8.28498

SAIFI - System Average Interruption Frequency Index

Month	Total Customer Interruptions	Total Customers Served	SAIFI
January	832	33000	0.02521
February	3139	33000	0.09512
March	2900	33000	0.08788
April	5334	33000	0.16164
May	5335	33000	0.16167
June	3066	33000	0.09291
July	16909	33000	0.51239
August	74	33000	0.00224
September	914	33000	0.02770
October	902	33000	0.02733
November	2713	33000	0.08221
December	5329	33000	0.16148

Total **47,447** **1.43779**

SERVICE RELIABILITY INDICES - 2003

SAIDI – System Average Interruption Duration Index

Time Period	Total Customer Hours of Interruptions	Total Customers Served	SAIDI
January	285.33333	33000	0.00865
February	1554.61667	33000	0.04711
March	1140.45	33000	0.03456
April	912.71667	33000	0.02766
May	2370.8333	33000	0.07184
June	7526.08333	33000	0.22806
July	494.45	33000	0.01498
August	1478.71667	33000	0.04481 without blackout
September	547.43333	33000	0.01659
October	1307.83333	33000	0.03963
November	1021.48333	33000	0.03095
December	7.05	33000	0.00021
Total	18647.00		0.56506

CAIDI - Customer Average Interruption Duration Index

Month	Total Customer Hours of Interruptions	Total Customer Interruptions	CAIDI
January	285.33333	155	1.84086
February	1554.61667	2642	0.58842
March	1140.45	2989	0.38155
April	912.71667	935	0.97617
May	2370.8333	3547	0.66841
June	7526.08333	570	13.20365
July	494.45	383	1.29099
August	1478.71667	5268	0.28070 without blackout
September	547.43333	356	1.53773
October	1307.83333	10812	0.12096

November	1021.48333	2891	0.35333
December	7.05	73	0.09658
Total	18647.00	30,621	21.33935

SAIFI - System Average Interruption Frequency Index

Month	Total Customer Interruptions	Total Customers Served	SAIFI
January	155	33000	0.00470
February	2642	33000	0.08006
March	2989	33000	0.09058
April	935	33000	0.02833
May	3547	33000	0.10748
June	570	33000	0.01727
July	570	33000	0.01727
August	5268	33000	0.15964
September	356	33000	0.01079
October	10812	33000	0.32764
November	2891	33000	0.08761
December	73	33000	0.00221
Total	30,621		0.93358

- ii. Whether or not Brantford Power has maintained the reliability performance for the three year period 2003 to 2005 in 2006, and if not, why not. Please identify the drivers that caused the 2006 performance to either improve or deteriorate from the historical performance;

RESPONSE:

BPI's analysis of its reliability performance indicates that reliability in 2006 improved over 2005 in most measures but was lower than the 2003 and 2004 period. The differences between 2003-2004 and 2006 appear to be related to increased scheduled outages pertaining to voltage conversion projects during 2006. Another factor was an outage on August 21, 2006 that resulted in loss of 50% of the load out of the Powerline substation. This was attributed to an outage on the Hydro One Networks Inc. transmission system from Burlington.

2006 results represented an improvement over 2005. The total customer interruptions were lower in 2006 than in 2005. There are a few factors that caused 2005 to have poor performance results. These included two instances of weather interruptions that created over 566,000 minutes of outages in one instance, and 104,000 minutes in the other; defective equipment, which resulted in a termination failure for 234,000 minutes; cable, termination and

transformer failure in the Brier Park location; and a foreign interference incident for 101,400 minutes, which was due to a vehicle accident.

As indicated in its 2008 Capital Budget [Exhibit 2 Tab 3 Schedule 1 Pages 30 and 31 of the Application], BPI is undertaking a voltage conversion project in the Applewood and Brier Park Subdivisions, completion of which will improve service reliability in those subdivisions.

- iii. Brantford Power's 2008 reliability improvement targets, if any, for the SAIDI, SAIFI, and CAIDI; and

RESPONSE:

Brantford Power has not established any specific targets in this regard.

- iv. If Brantford Power has established 2008 service reliability improvement targets, a copy of the plan that identifies programs or projects that Brantford Power will undertake to achieve these targets.

RESPONSE:

N/A

3.5 Ref: Exhibit 2/Tab 3/Schedule 4

This schedule discusses “Capitalization and Related Policies.” On page 1, Policy 19 – Accounting Policy – Capitalization and Policy 20 – Accounting Policy – Deferred changes are referenced:

- a) Re: Policy 19, and Indirect and Overhead Costs, Brantford Power’s policy change of September 2006 allowed such charges to be ascribed partially to capital projects (and hence rate base) and partially to operation expenses. For each of the years 2004 through 2008, please provide a table giving the dollar amounts of Indirect and Overhead Costs (actual or projected) as allocated to capital and the operating expenses.

RESPONSE:

INDIRECT AND OVERHEAD COSTS ALLOCATED TO CAPITAL AND OPERATING EXPENSES

INDIRECT COSTS ALLOCATED	2004	2005	2006 Actual	2007 Bridge	2008 Test
Operating Expenses	-	-	1,303,942	1,630,993	1,714,903
Recoverable (Billable)	-	-	-	(65,353)	(62,950)
Capital	-	-	(1,041,575)	(673,238)	(859,506)
sub-total	-	-	(1,041,575)	(738,591)	(922,456)
NET INDIRECT COSTS ALLOCATED TO DIRECTS	-	-	262,367	892,402	792,447

- b) In addition, please provide a calculation showing the quantitative effect of this policy change on an average residential bill for 2008.

RESPONSE:

Prior to the implementation of the current capitalization policy and without the smart meter rate adder, an average Residential customer at 1000 kWh per month would have experienced a monthly fixed charge of \$12.87 and a volumetric rate of \$0.0155/kWh, for a total bill of \$105.11. With the current capitalization policy, the fixed monthly charge will be \$12.29, the volumetric rate will be \$0.0149, and the total bill will be \$103.93 per month or a decrease of \$1.18 per month.

3.6 Ref: Exhibit 2/Tab 4/Schedule 1

This Exhibit discusses Brantford Power’s proposed Working Capital Allowance of 15%. On page 4, it is shown that for the 2007 bridge year as compared to the 2008 test year, the major contributor to operating expense (and hence Working Capital) is the Cost-of-Power, which increases from \$56,160,826 (2006 actual) to \$59,218,767 for 2007, a rise 5.4%. Please provide the values for the components that make up the cost of power: the volume of energy, and the unit cost of power.

RESPONSE:

Cost of Power

General Ledger Summary

DESCRIPTION	OEB MAPPING	2006 ACTUAL	2007 BRIDGE	2008 TEST
Power Purchased - IMO	SUPPLIES	4705	53,735,672	59,218,766
Power Purchased - BCP	ELECTCL MAT AND SUPPLY	4705	26,308	
Power Purchased - Sunoco	ELECTRICITY	4705	99,417	
Power Purchased - Global Adj	GLOBAL ADJUSTMENT	4705	3,013,752	
Power Purchased	RSVA ADJUSTMENT	4705	(714,322)	
			<u>56,160,826</u>	<u>59,218,766</u>
				<u>59,480,167</u>

Components that make up projected Cost of Power for 2007 Bridge & 2008 Test are as follows:

	2007 Bridge	2008 Test
Cost of Energy		
kWh	(1) 1,001,154,460	(1) 1,005,573,694
Cost of Power per IESO	\$0.06	\$0.06
Loss Factor Gross-up	<u>1.037</u>	<u>1.037</u>
	<u>59,218,767</u>	<u>59,480,167</u>
<u>kWh</u>		
Residential	285,882,423	294,990,955
General Service < 50	108,198,796	110,476,190
General Service > 50	597,254,915	589,977,774
USL, SL & Sntnl Lights	<u>9,818,326</u>	<u>10,128,775</u>
Total	<u>1,001,154,460</u>	<u>1,005,573,694</u>

Change

Notes: '(1) per Revenue load forecasts

**3.7 Ref: Exhibit 1/Tab 3/Schedule 4 page 1
Exhibit 2/Tab 3/Schedule 4**

- a) Is Brantford Power using the Board-prescribed interest rate, as per the Board's letter to LDCs dated November 28, 2006, for construction work in progress (CWIP) since May 1, 2006?

RESPONSE:

Yes

- b) If not, what interest rate has Brantford Power been using for CWIP?

RESPONSE:

N/A

- c) If not using the Board-prescribed interest rates, what would the impact on rate base, revenue requirement, and CWIP be if Brantford Power did use the prescribed interest rates?

RESPONSE:

N/A

4 COST OF CAPITAL

4.1 Ref: Exhibit 6/Tab 1/Schedule 2

In the table “Capital Structure”, Brantford Power has shown a short-term debt rate (under “Cost Rate”) of 4.77% for the 2008 Test Year. *The Board Report on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario Electricity Distributors*, issued December 20, 2006 (the “Board Report”) states the following in section 2.2.2:

“The Board had determined that the deemed short term debt rate will be calculated as the average of the 3-month bankers’ acceptance rate plus a fixed spread of 25 basis points. This is consistent with the Board’s method for accounting interest rate (i.e. short term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers’ acceptance rate as published on the Bank of Canada’s website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.

For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed short-term component of a distributor’s rate base. Further, consistent with updating of the ROE and deemed long-term tare, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates.” [Emphasis in original]

- a) Please provide the derivation of the 4.77% short-term debt rate estimate showing the calculations, data used and identifying data sources.

RESPONSE:

BPI used data from the Bank of Canada’s website at the time the Return on Capital was being prepared in June 2007. At that time, the average rate for the three-month bankers’ acceptances was 4.52%, resulting in a deemed short-term debt rate of 4.52% + 25 basis points = 4.77%.

- b) Please confirm if Brantford Power is proposing that the deemed short-term debt rate would be updated based on January 2008 Consensus Forecasts and Bank of Canada data, in accordance with the methodology documented in section 2.2.2 of Board Report.

RESPONSE:

Confirmed

- c) If Brantford Power is not proposing that the methodology in the Board Report be followed, please provide Brantford Power's reasons for varying from the methodology in the Board Report.

RESPONSE:

N/A

**4.2 Ref: Exhibit 6/Tab 1/Schedule 1 and
Exhibit 6/Tab 1/Schedule 4**

Brantford Power states that it is requesting a Return on Equity (“ROE”) of 8.68% per the Board’s formulaic approach as documented in Appendix B of the Board Report, with the final ROE for 2008 rate-setting purposes to be established based on January 2008 Consensus Forecasts and Bank of Canada data per the methodology in the Board Report (as stated in Exhibit 1/Tab 2/Schedule 1). The table “Return on Equity” shown on page 4 of Exhibit 6/Tab 1/Schedule 4 provides a summary of the calculation of the 8.68%. Please provide the source data used in the calculation and identify the specific data series, data sources and the date(s) of the data used in that table.

RESPONSE:

BPI understands that on August 1, 2007, Board staff advised Elenchus Research Associates that its calculation yielded an ROE of 8.68% based on the methodology described in the Board Report. As BPI’s representative, Elenchus then advised BPI of this rate which was discussed at the meeting between Board staff and Elenchus. The underlying details of the calculations were not communicated to BPI.

4.3 Ref: Exhibit 6/Tab 1/Schedule 3

Brantford Power provides data on its cost of debt in exhibit 6/Tab 1/Schedule 3 in the table labeled “Cost of debt”.

- a) In its 2006 EDR application filed under Board file number RP-2005-0020/EB-2005-0342, Brantford Power provided the following table in Sheet 3-4 of the 2006 EDR model:

Table 11

Schedule 5-1: Weighted Debt Cost								
		Size of Utility	Small	<i>Small</i>	<i>Medium-Small</i>	<i>Medium-Large</i>	<i>Large</i>	
		<u>Deemed Debt Rate</u>						
		Prior to 2000	Actual rate	<i>Actual rate</i>	<i>Actual rate</i>	<i>Actual rate</i>	<i>Actual rate</i>	
		2000 to 2005	7.25%	7.25%	7.00%	6.90%	6.80%	
		2006	6.25	6.25%	6.00%	5.90%	5.80%	
No.	Description	Debt Holder	Is the debt Holder affiliated with the LDC (Y/N)	Date of Issuance of debt (Date)	Principal (\$)	Term (Years)	Actual Rate (%)	Debt Rate Used for Weighted Debt Rate Cost
1	Promissory Note	Corp. of the City of Brantford	Y	Feb 1, 2006	\$24,189,168	5	6.25%	6.25%
2	Transformer Station	RBC	N	Feb 28, 2006	\$5,900,000	15	5.51%	5.51%
3	Tier 2 Rate Base Adjustment borrowing		N		\$2,809,000		6.00%	6.00%
Total					\$32,898,168			
Weighed Average Debt Cost							6.10%	6.10%

Please reconcile the debt rate (carrying costs [rate]) shown for the 2006 Board Approved year in the current application in Exhibit 6 Tab 1 Schedule 3 with the rates shown above, for I) the Note Payable to the Shareholder; and ii) Transformer Station

RESPONSE:

Long-Term Debt	Cost of Debt					
	Principal	2006 Board Approved		2006 Actual		Variance
		Rate	Carrying Cost	Rate	Carrying Cost	
Note Payable to Shareholder	24,189,168	6.25%	1,511,813	6.25%	1,511,813	
Transformer Station	5,900,000	6.00%	354,000	5.51%	325,090	(28,910)
Tier 2 Rate Base Borrowing Adjustment	2,809,000	6.00%	168,540			
	32,898,168		2,034,343		1,836,903	28,910

- b) The debt instrument labeled “tier 2 Rate Base Adjustment Borrowing”, with a principal of \$2,809,000 is shown only under 2006 Board approved. As noted in a) above this amount was applied and approved by the Board in Brantford Power’s 2006 EDR application Please provide an explanation as to why this debt does not appear in 2006 actual or in a subsequent year.

RESPONSE:

In the 2006 rate application BPI provided for borrowing of \$2,809,000 for the proposed Tier 2 capital program. In the 2006 rate application, this was the 2006 Mayfair Phase 2 voltage conversion project and the 2007 Coronation and Spring Gardens voltage conversion projects.

In the 2006 rate order, the 2006 voltage conversion project was approved and completed. Although BPI was not able to secure OEB approval of the 2007 project, which was no longer considered a Tier 2 project, BPI proceeded with the Coronation and Spring Garden Projects. In the capital borrowing schedule for the 2008 rate application, these borrowings are:

- Tier 2 Phase 1 Term Loan in the amount of \$1.2 million (Tier 2 Mayfair Gardens); and
- 2007 Voltage Conversion Project in the amount of \$1.109 million (previously 2007 Tier 2 Coronation / Spring Gardens)

2008 Test	Promissory Note	Corporation of the City of Brantford	Yes	January 31, 2006	5	\$24,189,168	6.25%	Fixed
	Transformer station loan	RBC Capital Markets	No	July 1, 2005	3.5	\$5,381,000	5.51%	Fixed
	Tier 2 Phase 1 Term Loan	RBC Capital Markets	No	June 1, 2006	5	\$1,012,000	5.77%	Fixed
	2007 Voltage Conversion Project Loan	OIPC	No	December 3, 2007	25	\$1,511,040	5.16%	Fixed
	Unspecified Borrowing	OIPC	No	December 3, 2007	25	\$812,160	5.16%	Fixed
	Unspecified Borrowing 2008	OIPC	No	June 1, 2008	25	\$3,186,662	6.00%	Fixed

d) Note 6 of Brantford Power’s 2006 Audited Financial Statements, filed in Exhibit 6/Tab 3/Schedule 1 Appendix a (page 15), states the following:

6. Long-Term Debt

	2006 \$	2005 \$
Note payable , bearing interest at 6.25%, repayable to the City, interest only payable annually - due February, 2011	24,189,168	24,189,168
Royal Bank non-revolving term facility with interest at prime repayable in quarterly instalments, due January, 2009	5,900,000	5,100,000
Royal Bank non-revolving term facility with interest at prime repayable in quarterly instalments due November, 2011	1,200,000	-
	31,289,168	29,289,168
Less current portion	308,000	-
	30,981,168	29,289,168

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.

The Company entered into a swap agreement 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 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.

- i. Please provide a copy of the Promissory Note to the city of Brantford referenced in the above;

RESPONSE:

A copy of the Promissory note is attached – Please refer to Attachment E to these responses.

- ii. Please indicate what, if any changes, have been made to the terms of the Promissory Note. Indicate also when and why changes were made. Please indicate if the rate of the Promissory Note changed.

RESPONSE:

When the Promissory Note was renewed in 2006, the interest rate changed from 9.00% to 6.25%. There have been no other changes made to the Promissory Note since 2006.

- iii. Please indicate under what terms the City of Brantford has to extend the maturity date. Are the interest rates and other terms negotiable should the City of Brantford exercise this option?

RESPONSE:

The terms under which the City of Brantford may extend the maturity date are:

“At the option of the City and with six (6) months prior written notice by the City to the Corporation (Brantford Power Inc.), 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 (Brantford Power Inc.) may agree upon (the “Extension Period Rate”)”

As stated in the Promissory Note, the interest rate is a fixed rate but is negotiable should the City exercise its option to extend the Promissory Note.

- iv. It would appear that the “swap agreements” entered into with the Royal Bank correspond with the debt labeled “Transformer Station” and “Tier 1 Phase 1 Term Loan”.
 - a. Please state if this is correct

RESPONSE:

Yes, this is correct.

- b. Please explain the differences between, or document the relationship between, the rates shown for these instruments (5.51% and 5.66%) in Exhibit 6 Tab 1 Schedule 3 versus those shown in Note 6 (4.71% and 4.97%)

RESPONSE:

b.

Loan	Fixed Rate	BA Stamping Fee	Total Combined Rate	Exhibit 6 Tab 1	Variance
Transformer Station Term Loan	4.71%	0.80%	5.51%	5.51%	0.00%
Tier 2 Phase 1 Term Loan	4.97%	0.80%	5.77%	5.66% *	-0.11%

* input error ; interest expense calculated using incorrect rate

Tier 2 Phase 1 Term Loan Impact of Error	Interest Expense		
	As filed	Corrected	Variance
2007 Bridge	62,769	63,989	1,220
2008 Test	57,279	58,392	1,113
	<u>120,049</u>	<u>122,382</u>	<u>2,333</u>

e) Please describe the purpose(s) of the capital projects for which Brantford Power incurred the debt labeled as “Unspecified Borrowing” with a principal of \$846,000 in the 2007 bridge year.

RESPONSE:

Unspecified Borrowing 2007 – this was not designated to any particular project but rather comprised the financing of a portion of BPI’s 2007 overall capital program. The borrowing was necessary to begin the transition of BPI’s capital structure to the deemed levels, which is the 60% debt, 40% equity structure required by the OEB.

f) Please describe the purpose(s) of the capital projects, and identify the capital projects if possible, for which Brantford Power forecasts that it will incur debt financing associated with the debt labeled “Unspecified Borrowing 2008”. Please provide the basis for the forecasted debt rate shown as 6.00%.

RESPONSE:

Unspecified Borrowing 2008 - this was not designated to any particular project but rather comprised the financing of a portion of BPI’s 2008 overall capital program. The borrowing was necessary to continue the transition of BPI’s capital structure to the deemed levels required by the OEB. The basis for the forecasted debt rate is RBC Financial Markets monthly report in September 2007. The rate that was forecasted was rounded for budgeting purposes.

- g) If necessary, please provide an update to Exhibit 6 Tab 1 Schedule 3, the Cost of Debt calculation in Exhibit 6 Tab 1 Schedule 4 and to the Capital Structure tables in Exhibit 6 Tab 1 Schedule 2.

RESPONSE:

Exhibit 6, Tab 1, Schedule 2, Schedule 3 and Schedule 4 have been updated to reflect the correct rate of 5.77% for the Tier 2 Phase 1 term loan. Please see the revised schedules in Attachments F and G and H.

5 SMART METERS

Brantford Power is not one of the thirteen licensed distributors authorized by Ontario Regulation 427/06 to conduct discretionary metering activities with respect to smart meters. In its decision on Brantford Power's 2007 IRM application (EB-2007-0510), the Board confirmed its understanding that Brantford Power would not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007.

5.1 Ref: Exhibit 2/Tab 3/Schedule 1 Exhibit 1/Tab 3/Schedule 2/Appendix A

On Exhibit 2/Tab 3/Schedule 1 page 23, section "12. Smart Metering Project Planning" for 2007, Brantford Power states:

"As an essential and nondiscretionary capital project, Brantford Power Inc. is working towards full-scale deployment of smart meters in 2009. In preparation for that deployment, Brantford Power Inc. has engaged a consultant to assist with evaluation of technologies and provide market and legislative intelligence. BPI notes that while this project has been included in the 2007 Capital Budget, costs and revenues are booked to Deferral Account 1555."

On the same page, Brantford power provides a table, indicating that the 2007 "enhancement" cost for the Smart Metering Project Planning will be \$60,000 and charged to USoA account 1555.

On Exhibit 1/Tab3/Schedule 2/Appendix A page 1, under the table "Pro Forma Financial Statements at December 31, 2007", Brantford Power indicates that the December 31, 2007 balance for the account "1555-Smart Meter Capital Variance Account" is a credit of \$150,152 and for the account "1556-Smart Meters OM&A Variance account" a debit of \$11,801.

- a) In light of its "un-named" status, please explain under what authority Brantford Power is undertaking smart meter activities. Please provide copies of any authorization Brantford Power has received to undertake smart meter activities.

RESPONSE:

Since its 2006 EDR Decisions, the OEB has been permitting Ontario distributors to recover smart meter-related rate riders. In its March 21, 2006 Decision with Reasons in RP-2005-0020/EB-2005-0529, which addressed certain generic matters raised in 2006 rate applications, including smart metering, the OEB states:

"This leaves the last and most difficult question; should utilities that have not proposed any expenditures on smart meters in 2006 be required to include a standard amount? The argument is that such an action will "jumpstart" the program. Put differently, the program will become a reality as opposed to a matter of discussion and debate.

We should remember that the vast majority of Ontario utilities have not included any smart meter expenditures in 2006 rates beyond those amounts previously committed as part of third tranche expenditures. To be fair, the government policy is clear and the timelines are tight.

The Board is of the view that given the increased need for electricity and the importance of conservation, specific funding should be included in 2006 rates be all Ontario utilities.”

The OEB confirmed that year-one expenditures of \$0.30 per residential customer per month are appropriate, and that such an amount should be included in 2006 rates. Distributors were also directed to establish variance accounts for both capital and operating expenses to track the difference between this amount and actual costs. (at p.7 of the Decision). BPI has been collecting the OEB-approved smart meter rate rider of \$0.30 since the 2006 rate year.

Since then, the provincial government named (by O.Reg.427/06) certain distributors as being authorized to conduct discretionary smart meter-related activities. BPI acknowledges that it is not among the named distributors. However, as the OEB acknowledged over two years ago, “the government policy is clear [regarding the installation of smart meters across the province] and the timelines are tight”. Two years later, BPI remains concerned that if it is not permitted to conduct at least preliminary work with respect to smart meters, this will jeopardize its ability to meet the government’s target of full smart meter installation by 2010.

Having collected smart meter funds for over two years, BPI submits that it is entirely appropriate that a portion of those funds be spent on preliminary smart meter work. Moreover, the OEB clearly wants distributors to undertake longer-term planning and in particular, capital programming and asset management planning. Consistent with this objective, BPI has been undertaking necessary planning activities leading to implementation of smart meters in 2009. Given the magnitude of the smart metering investment and the impact on operations, BPI considers such planning to be prudent and reasonable. There are costs associated with planning, however, and BPI has been using the revenues generated through the \$0.30 smart meter rate adder to cover such costs.

- b) Please indicate the number of smart meters that Brantford Power is planning to install in each of 2008 & 2009 and provide the associated capital cost for each year. Please provide also a breakdown of their number of installations and costs by customer classes for each year.

RESPONSE:

A breakdown of the smart meters by customer class and the associated capital cost for the years 2008 and 2009 is provided in Table 5.1.b.

Table 5.1.b.

Rate Class	Estimated # of Smart Meter Installations 2008	Estimated Capital Cost 2008	Estimated # of Smart Meter Installations 2009	Estimated Capital Cost 2009
Residential	0	\$134,418	33,546	\$5,388,233
GS<50 kW	0	\$10,118	2,654	\$405,566

c) Please provide a breakdown of costs for the 2007 capital budget of \$60,000, which is charged to account 1555.

RESPONSE:

\$60,000 represented an estimate of spending to the end of 2007. At the end of 2007, BPI had spent \$11,603 on consulting fees for the Smart Meter Initiative.

d) Please provide reconciliation of the December 31, 2007 credit balance of \$150,512 for USoA account 1555 with the 2007 cost of \$60,000 and the collection of the smart meter adder revenue from customers.

BPI notes that the credit balances for USoA account 1555 is actually \$150,152.00 as set out in “Pro Forma Financial Statements at December 31, 2007” as filed with the Application. The reconciliation below is based on the corrected amount being \$150,152.00. The \$1.00 difference between the reported amount and the reconciliation is due to rounding.

RESPONSE:

	1555	1557	Net
Op Balance 2007	(81,532)	1,803	(79,729)
REVENUE (smart meter adder)	(123,683)		(123,683)
EXPENSES	-	58,198	58,198
INTEREST IMPROVEMENT	(4,964)	27	(4,937)
Ending Balance 2007	(210,179)	60,028	(150,151)

- e) Please explain the nature of the smart meter OM&A costs of \$11,801 for December 31, 2007, which is charged to USoA account 1556, and provide an itemized cost breakdown of these costs.

RESPONSE:

Smart metering expenditures in 2006 in the amount of \$11,005.00 pertained to Phase 1 of Customer Information System programming for the billing of TOU [Time of Use] accounts, for which the deadline was originally May 1, 2006. Phase 1 included programming for the retail settlement of TOU accounts and the changes required for EBT. Although the original May 2006 deadline for this reprogramming was extended, BPI participated with other Daffron CIS users in the preparation and testing of the system at the earliest possible time to ensure that the CIS system could handle the requirements. Phase 1 did not include any interface with the MDMR but dealt with handling the data once the data was brought into the CIS system. This expenditure is identified at "Daffron Inv#67578 May/06 in the itemized cost breakdown provided below.

Other OM&A Costs in 2006 and 2007 pertain to accumulated interest improvements, as noted in the itemized cost breakdown below.

	1556
Daffron Inv#67578 May /06	11,005 *
Accumulated Interest Improvement:	
2006	290
2007	506
	11,801

* Package alteration for smart meter for Phase 1

**5.2 Ref: Exhibit 2/Tab 3/Schedule 1
 Exhibit 1/Tab 3/Schedule 2/Appendix B**

On Exhibit 2/Tab 3/Schedule 1 page 33, under “11. Smart Metering Project Planning” for 2008, Brantford Power states:

“As an essential and non discretionary capital project, Brantford Power Inc. is working towards full-scale deployment of smart meters in 2009. In 2008, Brantford Power will:

- Identify and repair unsafe meter bases in its service territory;
- Purchase, install and commission an automated meter change upgrade to its existing Customer Information System;
- Continue working with a consultant to assist in evaluation of technologies and provide market and legislative intelligence; and
- Obtain legal advice on AMI contracts, meter installation contracts and old meter disposal contracts.”

On the next page, Brantford Power provides a table, indicating that the 2008 “enhancement” cost for the Smart Metering Project Planning will be \$140,000, which is charged to USoA account 1555.

On Exhibit 1/Tab 3/Schedule 2/Appendix B page 1, under the table “Pro Forma Financial Statements at December 31, 2008”, Brantford Power indicates that the December 31, 2008 balance for the account “1555-Smart Meter Capital Variance Account” is a credit of \$141,548 and for the account “1556-Smart Meters OM&A Variance Account” a debit of \$12,306.

- a) Please provide a breakdown for the 2008 capital budget of \$140,000 for the cost categories identified by Brantford Power above in Exhibit 2/Tab 3/ Schedule 1 starting at page 33.

RESPONSE:

A breakdown of the planned capital budget of \$140,000 is shown in Table 5.2.a. below.

Table 5.2.a.

Spending Area	Amount
Consulting Services	\$20,000
Legal Review of AMI contract	\$20,000
Legal Review of AMCD installation contract	\$10,000
Legal Review of stranded meter recycling contract	\$4,000
Allocation for repair of unsafe meter bases	\$78,000
Detailed AMCD/AMRC propagation study	\$2,000
Contingency	\$6,000

b) Please provide reconciliation of the December 31, 2008 credit balance of \$141,548 for USoA account 1555 with the 2008 cost of \$140,000 and the collection of the smart meter adder revenue from the customers, starting with the opening credit balance of \$150,512 for January 1, 2008.

RESPONSE:

	1555	1557	Net
Opening Balance 2007	(81,532)	1,803	(79,729)
REVENUE (smart meter adder)	(123,683)		(123,683)
EXPENSES	-	58,198	58,198
INTEREST IMPROVEMENT	(4,964)	26	(4,938)
Ending Balance 2007	(210,179)	60,027	(150,152)
REVENUE (smart meter adder)	(124,921)		(124,921)
EXPENSES		140,000	140,000
INTEREST IMPROVEMENT	(6,475)		(6,475)
	(341,575)	200,027	(141,548)

c) Please confirm whether \$505, the difference between \$12,306 for December 31, 2008 and \$11, 801 for December 31, 2007, represents the carrying charges in 2008 for USoA account 1556. If not, please explain.

RESPONSE:

Yes. The \$505 difference between \$12,306 for December 31, 2008 and \$11,801 for December 31, 2007 represents the carrying charges in 2008 for USoA account 1556.

5.3 Ref: Exhibit 4/Tab 2/Schedule 3

On page 9, under the title “2006 Actual to 2007 Bridge Year”, Brantford Power provides a table for account “5065-Meter Expense” where a variance of \$186,726, between \$544,927 for 2007 bridge year and \$359,201 for 2006 actual, is reported and explained as follows:

- “Typical change in business unit work plans and priorities from year to year resulting in increase in labor and material costs from 2006 Actual to 2007 Bridge Year;
 - Increases in standard fleet charges for vehicles used by Meter Technicians.”
- a) Please confirm whether the correct amount for 2007 bridge year meter expense is \$545,927, instead of the \$544,927 as reported above.

RESPONSE:

The correct amount for the 2007 bridge year meter expense is \$545,927 and not \$544,927, as is incorrectly stated in Exhibit 4, Tab 2, Schedule 3, page 9. Accurate information is displayed in the OM&A cost table in Exhibit 4, Tab 2, Schedule 1, page 1.

- b) Please explain the 2007 increase of \$186,726, (52.0% increase) from the 2006 actual for meter expense and state whether any is associated with smart metering activities. If any is smart metering associated costs, please explain these smart meter costs in full and provide their dollar impact.

RESPONSE:

5065 – Meter Expense

Variance 2006 Actual vs 2007 Bridge

	<u>(‘000)</u>
Labour	\$ 40.0
Labour Burden	\$ 15.5
Education	\$ 8.3
Fleet Usage	<u>\$ 40.2</u>
	\$104.0
Contracted Services	\$ 28.0
Inventory write-offs	(\$ 36.1)
Indirects	<u>\$ 80.1</u>
	\$176.0
Other	<u>\$ 10.7</u>
	\$186.7

- Approved FTE not hired until June 2006.
- Education for new hire budgeted in 2007.
- Fleet usage follows labour. Meter technicians include/book vehicle time with labour hours.
- Contracted Services represents MSP service charges provided by Horizon Utilities that was reallocated from 5310 Meter Reading Expense in 2007, \$23.5k plus increase in meter re-verifications, \$4.5k.
- Increase in allocation of indirects to USoA 5065 due in part to increase in indirects.
- No amount of the variance is associated with smart meter activities.

5.4 Ref: Exhibit 4/Tab 2/Schedule 1

On page 1, under “OM&A Cost Table”, Brantford Power shows a negative variance of \$51,551 for “5065-Meter Expense”, please explain whether any of the 2008 decrease of \$51,551, for meter expense is associated with smart metering activities; if so, please explain these smart meter costs in full and provide their dollar impact.

RESPONSE:

No portion of the decrease in 2008 of \$51,551 is associated with smart metering activities.

5.5 Ref: Exhibit 2/Tab 2/Schedule 1 Page 10

The following table is a partial representation from the evidence for Account 1995, Contributions and Grants – Credit:

Table 13

	2006 Actual Gross Asset Value	Accumulated Depreciation	Net Book Value
1995-Contributions and Grants - Credit-Adjustments	0	0	0
1995-Contributions and Grants - Credit-Closing Balance	(1,015,463)	65,273	(950,190)
Average	(70,948)	3,910	(67,038)
Total	(2,030,926)	130,546	(1,900,380)

(Please note that the figures for “Total” are exactly double of those under title “Balance”).

- a) What are the meanings or definitions of line titles “Average” and “Total” for A/C No. 1995?
- b) Please demonstrate how the figures for “Average” are calculated.
- c) Please demonstrate how the figures for “Total” are calculated and why these figures are double those shown under “Balance”.
- d) Please identify what the figures under “Average” and “Total” represent.
- e) What are their effects on the rate base? Please demonstrate with an example.

RESPONSE: a-e

The ‘Average’ is the average of opening and closing balances. The totals stated for each account were incorrect, and in fact were unnecessary. As noted previously, a replacement Continuity Statement table for Exhibit 2, Tab 2, Schedule 1 has been produced. Please refer to Attachment C. Totals for each individual account have been removed, as they would be the same as the closing balances. The averages and totals calculated for each account have no bearing on rate base.

5.6 Ref: Exhibit 2/Tab 3/Schedule 1

On page 34, Brantford Power provides a table, indicating that the 2008 “enhancement” cost for the smart Meter Project Planning will be \$140,000, which is charged to USoA account 1555.

- a) Please confirm whether Brantford Power is requesting to maintain its current Smart Meter Adder of \$0.28 per month per metered customer which was approved by the Board on April 12, 2007 in EB-2007-0510;

RESPONSE:

Yes, BPI is requesting to maintain its current Smart Meter Rate Adder of \$0.28 per month per metered customer. This was mentioned in Exhibit 9, Tab 1, Schedule 1 pg 7 under proposed distribution rates, however the amount was not specified.

- b) If not, what is the amount of the smart Meter Rate adder that BPI is proposing for 2008? Please provide justification for the amount of this Smart Meter Rate Adder.

RESPONSE:

See BPI’s response to question 5.6 (a), above.

- c) If Brantford Power is intending to recover these costs other than through the Smart Meter Rate Adder, please explain.

RESPONSE:

BPI is not intending to recover these costs other than through the Smart Meter Rate Adder.

6 CONSERVATION AND DEMAND MANAGEMENT

6.1 Ref: Exhibit 5/Tab 1/Schedule 3 Appendix page 4

Please confirm that the 2006 result for “TRC Net Benefit” should be \$458,182 and not \$456,683.

RESPONSE:

An amount of \$1500 was deducted from the \$458,183, which was an indirect cost not attributable to any specific program. Therefore, the Net TRC benefit should be equal to \$456,683. The \$1500 was for the Canadian Energy Efficiency Corporate membership.

7 PILS

7.1 Ref: Exhibit - General

a) For the 2006 tax year, please provide the following:

- i. Actual federal T2 tax return and supporting schedules filed with the Ontario Ministry of Finance – signed original and any returns that were subsequently amended and re-filed;

RESPONSE:

Please see Attachment I to these responses.

- ii. Actual Ontario CT23 tax return and supporting schedules filed with the Ministry of Finance – signed original and any returns that were subsequently amended and re-filed. Please do not include any personal information for any individuals involved in apprentice training, etc.;

RESPONSE:

Please see Attachment J to these responses.

- iii. Financial statements that were submitted with the tax returns to the Ministry of Finance;

RESPONSE:

The financial statements submitted with the tax returns to the Ministry of Finance were the audited financial statements already included in BPI's application. Please refer to Copy of Audited Financial Statements for 2006 in Exhibit 1/Tab 3/ Schedule 1/Appendix A.

- iv. Notices of Assessment, and any Notice(s) of Re-assessment, including Statement of Adjustments, received from the Ministry of Finance for the 2006 tax year; and

RESPONSE:

Copies of Notices of Assessment accompany these responses as Attachment K. There were no Notice(s) of Re-Assessment issued for 2006.

- v. Any correspondence between the Ministry of Finance and Brantford regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review.

RESPONSE:

There is no correspondence, nor are any items in dispute or under review.

- b) Brantford used a combined income tax rate of 34.5% in its application for 2008. On December 14, 2007 federal Bill C-28 received Royal Assent. The federal tax rate for the applicant is now 19.5% effective January 1, 2008. Will the applicant use the new enacted income tax rates when it files its draft rate order?

RESPONSE:

BPI used the combined rate of 34.5% in its Application as this represented the enacted rate at the time the Application was filed. Yes, Brantford will be amending the rate to the current enacted rate when it files its draft rate order.

- c) Please provide the calculation of the Cumulative eligible Capital deduction amount for 2006, 2007 and 2008.

RESPONSE:

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION (CEC)	
Balance at the end of 2005 as per T2 Schedule 10	965,413
Less: Deduction x 7%	<u>67,579</u>
Balance at the end of 2006 as per T2 Schedule 10	897,834
Less: Deduction x 7%	<u>62,848</u>
Balance at the end of 2007 Bridge as projected	834,986
Less: Deduction x 7%	<u>58,449</u>
Balance at the end of 2008 Test as budgeted	<u>776,537</u>

7.2 Ref: Exhibit 4/Tab 3/Schedule 1 pages 1-2 Ontario Capital Tax (OCT) PILs

- a) Please provide the calculation of OCT, and explain the source of the taxable capital amount, the exemption deducted, and the tax rate selected.

RESPONSE:

	2006 Actual	2007 Bridge	2008 Test
Rate Base	64,055,039	67,699,150	70,179,032
Less: Exemption	10,000,000	12,500,000	14,550,000
Deemed Taxable Capital	<u>54,055,039</u>	<u>55,199,150</u>	<u>55,629,032</u>
Capital Tax Rate	0.3000%	0.2850%	0.2850%
Ontario Capital Tax	<u>162,165</u>	<u>157,318</u>	<u>158,543</u>

Rate Base for 2008 is the average of the 2007 and 2008 net book value of property, plant and equipment plus the working capital allowance of 15% of cost of power and controllable expenses.

The exemption deducted is the portion that is attributable to BPI.

The tax rate was the substantively enacted rate at the time of filing; that is, the tax rate of 0.285 percent was the rate in place at the time that the BPI rate Application was prepared. BPI notes that in the Federal mini-budget presented on October 30, 2007, the tax rate was reduced to 0.225 percent – that reduction in the tax rate had not been enacted at the time of the rate filing.

7.3 Ref: Exhibit 4/Tab 3/Schedule 1

Prior to repeating and responding to this question, BPI notes that it has restated Exhibit 4/Tab 3/Schedule 1 below to agree with internal supporting documentation, and to detail Other Additions and Deductions for clarity purposes. Please also refer to Attachment L, which replaces Exhibit 1/Tab 3/Schedule 2/Appendix A and B. Attachment L now reflects the pro forma results that should have been submitted in the Application.

INCOME TAX, LARGE CORPORATION TAX AND ONTARIO CAPITAL TAX TABLE

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
	(Rate PILs)	(Financial Statement PILs)	(Financial Statement PILs)	(Rate PILs)
<u>Determination of Taxable Income</u>				
Regulatory Net Income (before tax)	2,530,275	4,445,802	3,598,873	2,843,537
Additions to Accounting Income:				
Depreciation and amortization	2,357,112	2,771,699	3,030,907	3,274,649
Regulatory Asset Opening	8,887,185	5,256,108	2,590,604	-822,597
Actual Interest Expense				2,384,429
Other Additions	479,391	877,923	1,130,376	1,123,441
Total Additions	11,723,688	8,905,730	6,751,887	5,959,922
Deductions from Accounting Income:				
Capital Cost Allowance	2,126,535	2,841,656	3,167,810	3,547,430
Regulatory Asset Closing	8,320,494	2,590,604	-822,597	-2,026,651
Deemed Interest Expense				2,222,304
Other Deductions	1,098,645	913,870	918,434	911,487
Total Deductions	11,546,674	6,346,130	3,263,647	4,654,570
Taxable Income	2,708,289	7,005,402	7,087,113	4,148,889
 Corporate Income Tax Rate	 36.12%	 36.12%	 36.12%	 34.50%

Calculation of Utility Income Taxes

Income Taxes	978,233	2,530,351	2,559,865	1,431,367
Large Corporation Tax	-	-	-	-
	<u>978,233</u>	<u>2,530,351</u>	<u>2,559,865</u>	<u>1,431,367</u>
Income Taxes & LCT (grossed-up)	<u><u>1,531,361</u></u>	<u><u>N/A</u></u>	<u><u>N/A</u></u>	<u><u>2,185,293</u></u>

Other Additions:

Interest and penalties on taxes	-	14,622	16,500	-
Income or loss for tax purposes - joint venture or partnerships	4,870	3,408	3,500	3,500
Non-deductible portion of meals & entertainment expenses	-	4,307	5,000	5,000
Reserves - balance end of yr				
Allowance for doubtful accounts		410,000	410,000	410,000
Employee future benefits	474,521	445,586	443,038	439,005
Global Adjustment Reg Asset - Closing Balance	-		252,338	265,936
	<u>479,391</u>	<u>877,923</u>	<u>1,130,376</u>	<u>1,123,441</u>

Other Deductions:

Gain on disposal of assets per financial statements	-	24,441	-	-
CEC	72,665	67,579	62,848	58,449
Reserves - balance beginning of yr				
Allowance for doubtful accounts		330,000	410,000	410,000
Employee future benefits	474,521	491,850	445,586	443,038
Excess Interest	551,459			
	<u>1,098,645</u>	<u>913,870</u>	<u>918,434</u>	<u>911,487</u>

7.3 a) The regulatory net income reported for 2006 Actual is \$4,445,802, 2007 Bridge \$3,375,450, and 2008 Test \$2,843,537. Please explain the significant decline in net income from 2006 to 2007. Please explain the decline from 2007 to 2008.

RESPONSE:

Financial Statement (FS) PILs

Please note that 2007 Bridge Year Net Income was misstated in the Application when submitted and has been restated to agree with internal supporting documentation.

	2006 Actual (FS PILS)	2007 Bridge (FS PILS)	2008 Test (FS PILS)
Net Income (before tax)	4,445,802	3,598,873	4,305,326

Rate Setting PILs

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
	(Rate PILS)	(Rate PILS)	(Rate PILS)	(Rate PILS)

Regulatory Net Income (before tax) - Deemed Equity Return	2,530,275	2,882,477	3,046,462	2,843,537
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Comparing like amounts, it appears that *Regulatory Net Income before tax*, (per Rate Setting PILs), illustrates marginal changes across all the years presented.

Decline in *Net Income before tax*, (per FS PILs), from 2006 to 2007 of \$846,929, can be attributed to combination of spending shortfalls to plan in 2006 (please refer to BPI's response to School Energy Coalition Interrogatory 17a for further discussion in this regard) and increased spending in 2007, offset by an increase in Distribution Revenue.

Primary cause for decline *in Net Income before tax*, (per FS PILs), from 2006 to 2007, is attributable to increase in Total Controllable Expenses, by \$1,492,275 or 22.87%, as evidenced by Board Staff Table 1, per Exhibit 4/Tab 1/Schedule 2 page 1.

Increases can be summarized as follows:

		('000)
Directs		606
Indirects		585
		1,191
Decrease in Indirects Allocated to Capital/Billable		300
		1,491

- b) The depreciation and amortization numbers used to calculate PILs are not supported by the information on the following exhibits:
 Exhibit 4/Tab 1/Schedule 2 page 1; Exhibit 4/Tab 2/Schedule 7 page 1; Exhibit 1/Tab 3/Schedule 2 App A page 7; Exhibit 1/Tab 3/Schedule 2 App B page 7
- i) Please provide a table that shows the calculation of the amortization amounts that were used to calculate income tax PILs.
 - ii) Please explain how the numbers agree, or disagree, with other aspects of depreciation and amortization shown in this application.

RESPONSE: (b)i. & ii

The tables below reflect the CCA and the depreciation and amortization amounts that were used to calculate income Tax PILs above.

Totals presented now agree with Exhibit 4/Tab 3/Schedule 3

Amortization per Operating Statement is presented net of fleet depreciation. Fleet depreciation is included in total fleet costs, which are fully allocated to OM&A and Capital/Billable accounts. Refer to BPI's response to OEB Staff Q1.4(b), above, for further explanation regarding treatment of fleet costs. The table below reconciles total amortization expense used to calculate income tax PILs with amortization expense presented in Operating Expenses.

	2006 Actual	2007 Bridge	2008 Test
Total Amortization Expense	2,771,699	3,030,907	3,274,650
Deduct: Fleet depreciation	215,691	249,561	246,992
Net Amortization Expense	2,556,008	2,781,346	3,027,658

The totals in the Amortization Table below also agree with Exhibit 2/Tab 2/Schedules 1, 2 & 4.

<u>AMORTIZATION TABLE</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>
Capital Program			
Misc Intangible Plant		-	-
Land		-	-
Buildings		-	-
Transformer Station		-	-
Distribution Stations		-	-
Poles, Towers, & Fixtures		536,306	420,000
Distribution Lines - OH Conductors & Devices		706,546	465,000
Distribution Lines - UG Conduit		716,040	644,600
Distribution Lines - UG Conductors & Devices		1,564,606	1,335,400
Distribution Transformers		777,281	610,000

Services		194,472	325,000
Distribution Meters		436,369	363,000
Load Control Units		-	-
Vehicles 5yr		-	-
Vehicles 8yr		300,000	205,000
Tools		15,000	30,000
Communication Equipment		-	-
Supervisory System Equipment (SCADA)		200,000	190,000
Contributions & Grants		(362,250)	(374,400)
Other - Software		-	220,000
Distribution Smart Meters		-	-
New capitalization of indirect overhead		673,234	859,503
Allowance for Use of Funds During Construction		20,000	18,000
Total Capital Expenditures		5,777,604	5,311,103

Capital Assets (At cost)

Misc Intangible Plant	-	-	-
Land	208,241	208,241	208,241
Buildings	1,192,568	1,192,568	1,192,568
Transformer Station	4,468,614	4,468,614	4,468,614
Distribution Stations	140,682	140,682	140,682
Poles, Towers, & Fixtures	2,508	538,814	958,814
Distribution Lines - OH Conductors & Devices	18,109,180	18,815,726	19,280,726
Distribution Lines - UG Conduit	10,164	726,204	1,370,804
Distribution Lines - UG Conductors & Devices	21,616,178	23,180,784	24,516,184
Distribution Transformers	12,327,547	13,104,828	13,714,828
Services	325,730	520,202	845,202
Distribution Meters	6,375,852	6,812,221	7,175,221
Load Control Units	547,972	547,972	547,972
Vehicles 5yr	487,937	487,937	487,937
Vehicles 8yr	1,809,836	2,109,836	2,314,836
Tools	90,072	105,072	135,072
Communication Equipment	1,176	1,176	1,176
Supervisory System Equipment (SCADA)	-	200,000	390,000
Contributions & Grants	(1,015,464)	(1,377,714)	(1,752,114)
Other - Software	-	-	220,000
Distribution Smart Meters	-	-	-
New capitalization of indirect overhead	1,041,574	1,714,808	2,574,311
Allowance for Use of Funds During Construction	-	20,000	38,000
Total Capital Assets	67,740,367	73,517,971	78,829,074

Depreciation Expense - Regular

Misc Intangible Plant	-	-	-
Land	-	-	-
Building	23,851	23,851	23,851
Transformer Station	111,716	111,716	111,716
Distribution Stations	4,685	4,685	4,685
Poles, Towers, & Fixtures	100	21,552	38,352
Distribution Lines - OH Conductors & Devices	724,369	752,630	771,230
Distribution Lines - UG Conduit	406	29,048	54,832
Distribution Lines - UG Conductors & Devices	864,647	927,231	980,647
Distribution Transformers	493,101	524,192	548,592
Services	13,029	20,808	33,808
Distribution Meters	255,034	272,489	287,009
Load Control Units	54,797	54,797	54,797
Tools	9,007	10,507	13,507
Communication Equipment	235	235	235
Supervisory System Equipment (SCADA)	-	13,334	26,001
Contributions & Grants	(40,618)	(55,108)	(70,084)
Other - Software	-	-	44,000
Distribution Smart Meters	-	-	-
New capitalization of indirect overhead	41,649	68,578	102,959
Allowance for Use of Funds During Construction	-	800	1,520
Depreciation Expense - Regular	2,556,008	2,781,346	3,027,658
Allocated Depreciation			
Vehicles 5yr	36,940	33,310	21,704
Vehicles 8yr	178,751	216,251	225,288
Depreciation Expense - Allocated	215,691	249,561	246,992
Gross Depreciation	2,771,699	3,030,907	3,274,650

Accumulated Depreciation

Misc Intangible Plant	-	-	-
Land	-	-	-
Buildings	58,388	82,239	106,090
Transformer Station	221,163	332,879	444,594
Distribution Stations	28,745	33,430	38,115
Poles, Towers, & Fixtures	100	21,652	60,004
Distribution Lines - OH Conductors & Devices	3,858,685	4,611,315	5,382,545

Distribution Lines - UG Conduit	407	29,455	84,286
Distribution Lines - UG Conductors & Devices	4,163,986	5,091,217	6,071,864
Distribution Transformers	2,555,234	3,079,426	3,628,019
Services	17,866	38,675	72,483
Distribution Meters	1,254,528	1,527,017	1,814,026
Load Control Units	337,913	392,710	447,507
Tools	38,014	48,521	62,028
Communication Equipment	235	470	705
Supervisory System Equipment (SCADA)	-	13,334	39,335
Contributions & Grants	(65,272)	(120,380)	(190,464)
Other - Software	-	-	44,000
Distribution Smart Meters	-	-	-
New capitalization of indirect overhead	41,649	110,227	213,186
Allowance for Use of Funds During Construction	-	800	2,320
Vehicles 5yr	407,331	440,641	462,345
Vehicles 8yr	1,005,198	1,221,449	1,446,737
Total Accumulated Depreciation	13,924,170	16,955,077	20,229,727

Net Book Value of Fixed Assets

Misc Intangible Plant	-	-	-
Land	208,241	208,241	208,241
Buildings	1,134,180	1,110,329	1,086,478
Transformer Station	4,247,451	4,135,735	4,024,020
Distribution Stations	111,937	107,252	102,567
Poles, Towers, & Fixtures	2,408	517,162	898,810
Distribution Lines - OH Conductors & Devices	14,250,495	14,204,411	13,898,181
Distribution Lines - UG Conduit	9,757	696,749	1,286,518
Distribution Lines - UG Conductors & Devices	17,452,192	18,089,567	18,444,320
Distribution Transformers	9,772,313	10,025,402	10,086,809
Services	307,864	481,527	772,719
Distribution Meters	5,121,324	5,285,204	5,361,195
Load Control Units	210,059	155,262	100,465
Tools	52,058	56,551	73,044
Communication Equipment	941	706	471
Supervisory System Equipment (SCADA)	-	186,666	350,665
Contributions & Grants	(950,192)	(1,257,334)	(1,561,650)
Other - Software	-	-	176,000
Distribution Smart Meters	-	-	-
New capitalization of indirect overhead	999,925	1,604,581	2,361,125

Allowance for Use of Funds During Construction	-	19,200	35,680
Vehicles 5yr	80,606	47,296	25,592
Vehicles 8yr	804,638	888,387	868,099
Total Net Book Value of Capital Assets	53,816,197	56,562,894	58,599,347

CCA TABLE

	<u>2006</u>	<u>2007</u>	<u>2008</u>
Capital Program			
Land		-	-
Buildings		-	-
Transformer Station			
Distribution Stations		-	-
Poles, Towers, & Fixtures		536,306	420,000
Distribution Lines - OH Conductors & Devices		706,546	465,000
Distribution Lines - UG Conduit		716,040	644,600
Distribution Lines - UG Conductors & Devices		1,564,606	1,335,400
Distribution Transformers		777,281	610,000
Services		194,472	325,000
Distribution Meters		436,369	363,000
Load Control Units		-	-
Vehicles 5yr		-	-
Vehicles 8yr		300,000	205,000
Tools		15,000	30,000
Communication Equipment		-	-
Supervisory System Equipment (SCADA)		200,000	190,000
Contributions & Grants		(362,250)	(374,400)
Other - Software		-	220,000
Distribution Smart Meters		-	-
New capitalization of indirect overhead		673,234	859,503
Allowance for Use of Funds During Construction		20,000	18,000
		<u>5,777,604</u>	<u>5,311,103</u>

Undepreciated Capital Cost - Beginning of Year

Land		-	-
Buildings		39,884,726	38,289,337
Transformer Station		-	-
Distribution Stations		-	-
Poles, Towers, & Fixtures		-	514,854
Distribution Lines - OH Conductors & Devices		-	678,284
Distribution Lines - UG Conduit		-	687,398

Distribution Lines - UG Conductors & Devices	13,593,904	14,008,413
Distribution Transformers	-	746,190
Services	-	186,693
Distribution Meters	-	418,914
Load Control Units	50,652	40,522
Vehicles 5yr	35,764	25,035
Vehicles 8yr	623,483	691,438
Tools	-	13,500
Communication Equipment	-	-
Supervisory System Equipment (SCADA)	-	180,000
Contributions & Grants	-	(347,760)
Other - Software	-	-
Distribution Smart Meters	-	-
New capitalization of indirect overhead	-	646,305
Allowance for Use of Funds During Construction	-	19,200
Total UCC Beginning of Year	54,188,529	56,798,323

Capital Cost Allowance

Land	-	-
Building	1,595,389	1,531,573
Transformer Station	-	-
Distribution Stations	-	-
Poles, Towers, & Fixtures	21,452	57,988
Distribution Lines - OH Conductors & Devices	28,262	72,863
Distribution Lines - UG Conduit	28,642	80,776
Distribution Lines - UG Conductors & Devices	1,150,097	1,174,089
Distribution Transformers	31,091	84,095
Services	7,779	27,935
Distribution Meters	17,455	48,033
Load Control Units	10,130	8,104
Vehicles 5yr	10,729	7,510
Vehicles 8yr	232,045	238,181
Tools	1,500	5,700
Communication Equipment	-	-
Supervisory System Equipment (SCADA)	20,000	55,000
Contributions & Grants	(14,490)	(42,797)
Other - Software	-	110,000
Distribution Smart Meters	-	-
New capitalization of indirect overhead	26,929	86,084
Allowance for Use of Funds During Construction	800	2,256
Total CCA	2,841,656	3,167,810

Undepreciated Capital Cost - End of Year

Land	-	-	-
Building	39,884,726	38,289,337	36,757,763
Transformer Station	-	-	-
Distribution Stations	-	-	-
Poles, Towers, & Fixtures	-	514,854	876,865
Distribution Lines - OH Conductors & Devices	-	678,284	1,070,421
Distribution Lines - UG Conduit	-	687,398	1,251,223
Distribution Lines - UG Conductors & Devices	13,593,904	14,008,413	14,169,724
Distribution Transformers	-	746,190	1,272,095
Services	-	186,693	483,758
Distribution Meters	-	418,914	733,881
Load Control Units	50,652	40,522	32,417
Vehicles 5yr	35,764	25,035	17,524
Vehicles 8yr	623,483	691,438	658,257
Tools	-	13,500	37,800
Communication Equipment	-	-	-
Supervisory System Equipment (SCADA)	-	180,000	315,000
Contributions & Grants	-	(347,760)	(679,363)
Other - Software	-	-	110,000
Distribution Smart Meters	-	-	-
New capitalization of indirect overhead	-	646,305	1,419,723
Allowance for Use of Funds During Construction	-	19,200	34,944
Total UCC End of Year	54,188,529	56,798,323	58,562,033

7.3(c) For “Other” additions shown in 2006, 2007 and 2008, please provide a table that identifies each item included in the respective totals of \$2,680,126, \$4,903,079, and \$1,831,333 and explains the following:

- i. Why it should be allowed as an addition.
- ii. If any of the addition items relates to regulatory asset recoveries, the regulatory precedent that would allow this specific addition.

RESPONSE:

	2006 Actual	2007 Bridge	2008 Test
	(Financial Statement PILS)	(Financial Statement PILS)	(Rate PILS)
Other Additions:			
Interest and penalties on taxes	14,622	16,500	-
Income or loss for tax purposes - joint venture or partnerships		3,500	3,500
Actual Interest Expense		2,040,137	2,384,494
Regulatory Asset Opening	-	2,590,604	(822,597)
Regulatory Asset Change	2,665,504	-	-
Global Adjustment Reg Asset - Closing Balance		252,338	265,936
	2,680,126	4,903,079	1,831,333

i. BPI submits that these amounts should be allowed as additions for the 2008 Test Year because they are reconciling items that must be added to accounting income to calculate taxable income on which PILs is based. It should be noted that the actual interest expense figure of \$2,384,494 for 2008 included 6035 - Other Interest Expense and 6042 - Allowance for Other Funds Used During Construction. This is incorrect and should be limited to the amounts in 6005 - Interest on Long Term Debt and 6030 - Interest on Debt to Associated Companies totaling \$2,097,267.

BPI believes that the portion of RSVA – Cost of Power 1588 that relates to the Global Adjustment (GA) should be ignored for tax purposes. BPI has confirmed this with its external tax experts. Global Adjustment variances are short-term timing differences between what is paid to the IESO and what is collected from BPI’s customers. The GA monthly rate charged by the IESO each month is typically recovered from customers in the following month, and therefore should not be included for tax purposes.

ii. BPI is not aware of a regulatory precedent that would allow this specific addition.

7.3(d) For “Other” deductions shown in 2006, 2007 and 2008, please provide a table that identifies each item included in the respective totals of \$92,020, \$1,462,555, and \$254,102. Please explain the reasons for each deduction.

RESPONSE:

	2006 Actual	2007 Bridge	2008 Test
Other Deductions:			
Gain on disposal of assets per financial statements	24,441	-	-
Cumulative Eligible Capital	67,579	62,848	58,449
Regulatory Asset Closing	-	(822,597)	(2,026,651)
Deemed Interest Expense		2,222,304	2,222,304
	92,020	1,462,555	254,102

These amounts should be allowed as deductions for the 2008 Test Year because they are reconciling items that must be subtracted from accounting income to calculate taxable income on which PILs is based.

7.4 Ref: Exhibit 4/Tab 3/Schedule 3 pages 3-8

- a. Please provide a table that shows the categories of capital expenditures applied for in this application, totals for each year 2006, 2007, 2008 and how these amounts were allocated to the additions column in the capital cost allowance (CCA) schedules for 2006, 2007 and 2008.

RESPONSE:

BRANTFORD POWER CAPITAL BUDGET

DESCRIPTION	TAX CLASS	2006 ACTUAL	2007 BRIDGE	2008 BUDGET
NEW LINES AND EQUIPMENT				
NEW SERVICES (ROLL INS)		349,685	320,141	380,270
NEW O/H LINE EXTENSIONS		209,429	321,269	223,860
NEW U/G LINE EXTENSIONS		350,644	134,546	258,151
NEW OVERHEAD TRANSFORMERS		51,099	97,234	175,347
NEW UNDERGROUND TRANSFORMERS		721,032	540,191	219,183
LAND TRANSFER LINE EXTENSIONS - LOAD TRANSFERS		-	41,742	-
NEW SUBDIVISIONS COST		801,986	766,227	1,067,023
CIVIC SQUARE DOWNTOWN - PH3		42,688	131,353	-
CITY/MTO RELOCATION O/H		202,887	626,126	370,547
OAK PARK NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS		12,023	238,524	343,099
JOHNSON RD RELOCATION		-	71,557	-
BELL LANE EXTENSION		260,562		
BELL LANE EXTENSION		7,608		
TRANSFORMER STATION >50KV		91,631		
TRANSFORMER STATION >50KV		100,881		
TRANSFORMER STATION >50KV		27,987		
	47	3,230,142	3,288,910	3,037,480
CONVERSION OF LINES FROM 4/8KV TO 27KV (Tier 2)				
POLES, TOWERS, & FIXTURES			-	17,711
OH CONDUCTORS & DEVICES		6,145	-	31,281
UG CONDUIT			431,865	287,291
UG CONDUCTORS & DEVICES		1,071,998	1,033,485	657,601
LINE TRANSFORMERS		285,364	202,335	273,979
	47	1,363,507	1,667,685	1,267,864

REBUILD OF EXISTING LINES AND EQUIPMENT				
POLES, TOWERS, & FIXTURES		2,508	-	82,652
OH CONDUCTORS & DEVICES		332,898	210,309	172,046
UG CONDUIT		10,163	-	-
UG CONDUCTORS & DEVICES		183,190	-	-
LINE TRANSFORMERS		-	-	-
	47	528,759	210,309	254,698
PROVISION FOR PURCHASE OF LINES FROM BRANT COUNTY POWER		-	-	-
UPGRADE AM/FM & GIS SYSTEM	12	-	-	220,000
LAND (for new building) BUILDING				
SCADA AND DISTRIBUTION AUTOMATION	8	105,991	200,000	190,000
SUBTOTAL		5,228,399	5,366,904	4,970,042
METERING				
METERING(METERS+INSTRUMENT TRANSFORMERS)		607,903	353,004	447,371
WHOLESALE METERING (BRANTFORD TS)		202,634	-	33,090
CONDO Sub-metering		-	104,946	-
SUBTOTAL	47	810,537	457,950	480,461
VEHICLES	10	236,947	300,000	205,000
TOOLS	8	27,882	15,000	30,000
COMMUNICATION EQUIPMENT	8	1,176		
CAPITAL BUDGET - GROSS		6,304,941	6,139,854	5,685,503
RECOVERIES/CAPITAL CONTRIBUTIONS	47	(399,115)	(362,250)	(374,400)
CAPITAL BUDGET - NET		5,905,826	5,777,604	5,311,103

ALLOCATIONS TO CAPITAL COST ALLOWANCE SCHEDULES

2006 ACTUAL 2007 BRIDGE 2008 BUDGET

	TAX CLASS	8	29,058	215,000	220,000
	TAX CLASS	10	236,947	300,000	205,000
	TAX CLASS	12	-	-	220,000
	TAX CLASS	47	5,639,821	5,262,604	4,666,103
			5,905,826	5,777,604	5,311,103
per TAX Schedules (Exhibit 4/Tab 3/Schedule 3)			5,977,225	5,778,062	5,311,157
	difference		(71,399)	(458)	(54)
			(1)	(2)	(2)
	(1)		Regulatory Expenses Capitalized for Tax Purposes (CDM)		
	(2)		AFUDC rounding		

In comparing the summary of the capital spending with the capital spending presented in the Capital Cost Allowance schedules, the differences result from:

- In 2006, capitalization of CDM spending added to Tax Class 47, for tax purposes only (Note 1); and
- In 2007 and 2008, AFUDC rounding (Note 2).

b. Please provide a table showing the movement in construction work in progress (CWIP) from 2006 to 2008.

RESPONSE:

CWIP MOVEMENT	\$
2006 ACTUAL - not measured in 2006	0
2007 BRIDGE Opening	0
CAPEX - WIP during year	445,575
COMPLETED and CAPITALIZED	(445,575)
2007 BRIDGE Ending	0
2008 BRIDGE Opening	0
CAPEX - WIP during year	315,596
COMPLETED and CAPITALIZED	(315,596)
2008 TEST Ending	0

8 FORECASTING

8.1 Ref: Exhibit 3/Tab 2/Schedule 1 page 1

On page 1 Brantford Power states that the weather normalization that was generated was performed by Hydro One. Please provide the Hydro One report and any spreadsheets containing data supporting the calculation of the normalized historical load.

RESPONSE:

The requested Hydro One spreadsheet accompanies these responses as an attachment. See Attachment M, HydroOne_Brantford_RUN1.xls [the “Hydro One Spreadsheet”].

For the GS>50 kW class, BPI removed the 2004 retail energy associated with one customer from the Hydro One actual weather wholesale energy and the weather-normalized wholesale energy as this customer shut down during 2007. BPI believes this customer will not restart during 2008.

With the original Application, BPI filed as evidence, “Data_Brantford Power Inc. Load Forecasts E3_T2_S3_AA.xls” [the “BPI Spreadsheet”]. The modified values for the actual weather wholesale energy and the weather-normalized wholesale energy can be found in columns X and W respectively on Tab “GS > 50” of the BPI Spreadsheet.

8.2 Ref: Exhibit 3/Tab 2/Schedule 1 page 1

In pages 1 to 5 Brantford Power explains how it developed its 2008 load forecast. While some details are missing, the essential approach used for the weather sensitive loads appears to be that Brantford Power:

- a. Determined the 2008 forecasted customer count for each customer class,
- b. Determined the weather-normalized retail energy for each customer class for 2004,
- c. Determined the 2004 retail normalized average use per customer (“retail NAC”) for each class by dividing each of the weather normalized retail energy values by the corresponding number of customers/connections in each class existing in 2004,
- d. Applied the 2004 retail NAC for each class to the 2008 Test Year without modification, and
- e. Determined the 2008 Test Year energy forecast for each customer class by multiplying the applicable 2004 retail NAC value for each class by the 2008 forecasted customer count in that class.

Please:

- a. Confirm that the above is the essence of Brantford Power’s load forecasting methodology for weather sensitive loads,

RESPONSE:

The above description of the load forecast methodology is in essence the method used to determine the weather normalized values for the weather sensitive classes (i.e. Residential, GS<50 kW and GS > 50 kW classes).

- b. Differentiate the approach used for weather sensitive loads from that used for non-weather sensitive loads, and

RESPONSE:

For the non-weather sensitive classes such as Street Lighting, Sentinel Lights and Unmetered Scattered Load, an average usage per connection was calculated for each class. For Street Lighting the average was calculated from 2004 data. For Sentinel Lights the average was calculated based on 2004 through 2006 data. For Unmetered Scattered Load the average was calculated based on the most recent 60 months of actual data. These average usages are applied to the forecasted number of connections in 2008.

For the non-weather sensitive Stand-by class, average monthly usage was calculated based on the past 5 years of actual data. The monthly average usages were used to forecast the annual usage for 2008.

c. Fully correct any errors in the above explanation.

RESPONSE:

To BPI's knowledge, there are no errors in the above explanation.

With respect to section d of the OEB Staff description of the approach, BPI determined the class loss factor for each class by dividing the actual weather wholesale energy values by the actual retail energy retail values. BPI determined the weather-normalized retail energy values by dividing the weather-normalized wholesale energy value by the class loss factor.

8.3 Ref: Exhibit 3/Tab 2/Schedule 2 pages 3-5

In page 3, Table 3.2.2-3, Brantford Power shows the calculation of the retail NAC for the three customer classes it considers to be weather sensitive. As described in the previous interrogatory, it appears that Brantford Power then applied the 2004 retail NAC for each weather sensitive class to the 2008 Test Year (and the 2007 Bridge Year) without modifications. In page 5, Table 3.2.2-4, Brantford Power appears to multiply the retail NAC by the forecasted customer count for 2007 and 2008 to obtain the respective kWh load values. While the foregoing is Board staff's understanding of the calculation that Brantford Power employed, Board staff is not able to replicate the values in the table mentioned.

For each of the three weather sensitive classes, please:

- a. Show the detailed calculation of the "Weather Normal Wholesale kWh (2004)" values shown in Table 3.2.2-3.

RESPONSE:

The Weather Normal Wholesale kWh (2004) for the Residential and GS < 50 kW classes are taken directly from the Hydro One Spreadsheet provided as attachment M in response to OEB staff interrogatory 8.1. See cells O20 and O24.

BPI determined the Weather Normal Wholesale kWh (2004) for the GS > 50 kW class by subtracting 18,740,494 kWh (representing the 2004 kWh from the closed customer) from the Hydro One Spreadsheet cell O21. The 18,740,494 kWh which was subtracted can be found in cells AH23:AH34 of the BPI Spreadsheet on the GS>50 tab.

- b. Show the detailed calculation of the Retail NAC" values shown in table 3.2.2-3.

RESPONSE:

BPI determined the Retail NAC for the Residential and GS < 50 kW classes from the average of the 12 monthly Retail NAC calculated for the 12 months of 2004 for the particular class. The monthly value for the Retail NAC was determined by dividing the weather-normalized retail energy by the number of customers at the end of the month. See BPI Spreadsheet "Residential" tab column I divided by column D for the Residential class. BPI Spreadsheet "GS < 50" tab column O divided by column J.

BPI determined the Retail NAC for the GS > 50 kW class by dividing the average weather-normalized retail energy for 2004 by the number of customers in the class at year-end. See BPI Spreadsheet "GS > 50" tab cell Z35 divided by 12 divided by cell U34.

The detailed explanation of the calculation of the weather-normalized retail energy was provided in the response to Board Staff Interrogatory 8.2(h).

- c. Show the detailed calculation of the “kWh” values shown in table 3.2.2-4,

RESPONSE:

BPI determined actual energy values from billing system data.

BPI used the energy values submitted in their EDR 2006 Model for the Board Approved data.

BPI determined normalized energy values by multiplying the class retail NAC by the appropriate number of customers or connections for the applicable year.

BPI determined estimated energy values from a combination of billing system data for the months where such data was complete and of normalized energy values for the remainder of the year. These normalized values are the product of the class retail NAC multiplied by the forecast number of customers or connections.

BPI determined the forecast energy values by multiplying the class retail NAC by the forecast number of customers or connections for the applicable year.

- d. Re-file Table 3.2.2-3, table 3.2.2-4 and any other table in the application as may be necessary to correct any calculation errors or changes, and

RESPONSE:

BPI does not believe there are any calculation errors or changes to energy values in Tables 3.2.2-3 or 3.2.2-4.

- e. Provide any additional information necessary to clarify the calculations made by BPI with respect to items a) to d) above.

RESPONSE:

BPI has provided additional information in its responses to sections a, b and c of this interrogatory.

8.4 Ref: Exhibit 3/Tab 2/Schedule 2 page 3

BPI outlines on page 3 the method used for determining the class loss factors. Please provide:

- a. The rationale and detailed description of this process, and

RESPONSE:

The class loss factor is used in the calculation of NAC values used to forecast or normalize energy values. Normalization allows BPI to use its customer forecast to produce an energy forecast for each of the Residential, GS<50 kW and GS >50 kW classes. It is determined by dividing the actual wholesale energy from the Hydro One Spreadsheet for each class by the actual 2004 retail sales for the class.

- b. Supporting source values and calculations.

RESPONSE:

The supporting values and calculations are provided in the Hydro One Spreadsheet provided as Attachment M to these responses and also the BPI Spreadsheet filed with the Application.

8.5 Ref: Exhibit 3/Tab 2/Schedule 2 page 4

BPI notes on page 4: “Billed kW is estimated based on a load factor calculated using a ratio of historical billed kW to historical retail kWh, by class.” Please provide:

- a. The rationale and detailed description of this process, and

RESPONSE:

For classes that have \$/kW distribution volumetric charges, the billed kW was based on the weighted average ratio of historical billed kW to historical billed kWh. The ratio allows BPI to forecast billed kW based on the forecast energy for each of these classes. The ratio for each class was determined by dividing the sum of 60 months worth of billed kW by the sum of the same 60 months worth of billed kWh. The weighted average ratio was applied to the 2008 weather-normalized kWh to determine the 2008 billed kW.

- b. Supporting source values and calculations.

RESPONSE:

The following tables provides the calculation of the ratios referenced in a) and how they are used to determine the 2008 kW by rate class.

GS > 50 kW class

Year ¹	2002	2003	2004	2005	2006
kWh	536,571,898	546,310,694	573,938,064	579,512,912	597,532,271
kW	1,334,500	1,402,164	1,435,427	1,432,005	1,458,441
kW/kWh	0.0024871	0.0025666	0.0025010	0.0024710	0.0024408

Weighted Average kW/kWh: 0.0024905
 2008 Forecasted kWh: 588,310,448
 2008 Forecasted Billed Kw: 1,635,606

Sentinel Lighting class

Year ²	2002	2003	2004	2005	2006
kWh	627000	526,717	546,166	545,615	555,133
kW	1600	1,756	1,750	1,819	1,850
kW/kWh	0.00255	0.00333	0.00320	0.00333	0.00333

Weighed Average kW/kWh: 0.0033189
 2008 Forecasted kWh: 549,290

¹ Year represents 12 consecutive months starting at April of the specified year. 2002 data is not available before April 2002.

² Year represents 12 months of the calendar year.

2008 Forecasted Billed kW: 1,823

Street Lighting class

Year ³	2002	2003	2004	2005	2006
kWh	5,977,227	6,178,542	6,360,781	6,865,003	7,066,634
kW	18,667	18,783	19,386	20,928	21,523
kW/kWh	0.003123	0.003040	0.003048	0.003049	0.003046

Weighed Average kW/kWh: 0.0030718
 2008 Forecasted kWh: 7,244,141
 2008 Forecasted Billed kW: 22,253

³ Year represents 12 consecutive months starting at June of the specified year. 2002 data is not available before June 2002.

**8.6 Ref: Exhibit 3/Tab 2/Schedule 2 page 1
Exhibit 3/tab 2/Schedule 5 page 1**

In Exhibit 3/Tab 2/Schedule 2 page 1 Table 3.2.2-1, the 2006 number of customers in various customer classes differ from the corresponding number in the table on Exhibit 3/Tab 2/Schedule 5 page 1

Please:

- a. Clarify which numbers are correct, and

RESPONSE:

The various customer numbers shown in Table 3.2.2-1 are the number of customers in each class at December of the particular year as determined from billing system data (through 2006) or as forecast (2007 and beyond). GS customer numbers are shown along the left vertical axis of the graph; Residential customer numbers are shown along the right vertical axis.

The 2006 Board Approved customer numbers shown in Exhibit 3/Tab 2/Schedule 5 page 1 were obtained from the input to the 2006 EDR model.

The 2006 Actual customer numbers shown in Exhibit 3/Tab 2/Schedule 5 page 1 were obtained from the input to the 2006 year-end RRR filings.

BPI believes that both sets of customer numbers are correct. Table 3.2.2-1 has been presented for the purpose of illustrating trends, while the customer counts in Exhibit 3, Tab 2, Schedule 5 are used for rate-making purposes.

- b. Re-file any tables in the application that may require to be updated as a result of the clarification.

RESPONSE:

No tables in the Application require updating as a result of this clarification.

8.7 Ref: Exhibit 3/Tab 2/Schedule 2

BPI explains how it determined the 2004 retail normalized average use per customer (“retail NAC”) for each class and apparently used this value for other years also. This does not appear to adequately weather normalize the energy usage in historical years and does not allow for the possible change in energy usage per customer over the 2002 –2008 period due, for example, to Conservation and Demand Management. The minimal amount of weather normalization and the constant retail energy assumption could potentially lead to forecasting errors.

- a. Please file a data table for the historical years 2002 to 2006 (and for the year 2007 if the actual values are available) that shows:
 - i. The actual retail energy (kWh) for each customer class in each year,

RESPONSE:

The following table outlines the actual retail energy (kWh) for each customer class for 2002 to 2006.

Customer Class	2002	2003	2004	2005	2006
Residential	282,124,517	274,321,462	272,962,945	296,391,192	283,166,279
GS<50 kW	95,889,739	95,594,339	97,811,277	104,202,845	102,694,059
GS>50 kW	519,645,524	538,721,112	572,365,136	580,601,470	590,877,017
USL	2,568,691	2,506,207	2,731,761	2,576,389	2,184,751
Sentinel Lighting	627,000	526,717	546,166	545,615	555,133
Street Lighting	6,768,940	6,116,876	6,269,377	6,635,713	6,975,374
total	907,624,411	917,786,713	952,686,662	990,953,224	986,452,613

- ii. The weather normalized retail energy (kWh) for each customer class in each year (where, for the customer classes that BPI has identified as weather sensitive, the weather conversion of the actual load to the weather normalized load using a normalization factor for that year and not rely on results for any other year),

RESPONSE:

The following table outlines the weather normalized retail energy (kWh) for each customer class for 2002 to 2006. The classes that have been identified as weather sensitive are the Residential, GS < 50 kW and GS > 50 kW classes.

Customer Class	2002	2003	2004	2005	2006
Residential	131,619,008	136,602,742	136,480,811	142,640,792	141,037,930
GS < 50 kW	63,739,759	64,410,594	65,580,082	65,675,914	63,728,966
GS > 50 kW	135,124,247	141,913,961	147,172,714	142,283,802	176,065,461
Sentinel Lights	304,353	309,564	303,660	306,916	342,469
Streetlights	2,793,818	3,461,352	3,497,643	3,409,153	3,060,430
USL	231,982	471,986	406,396	406,396	406,396
Total	333,813,167	347,170,199	353,441,306	354,722,974	384,641,652

8.7 Ref: Exhibit 3/Tab 2/Schedule 2

BPI explains how it determined the 2004 retail normalized average use per customer (“retail NAC”) for each class and apparently used this value for other years also. This does not appear to adequately weather normalize the energy usage in historical years and does not allow for the possible change in energy usage per customer over the 2002 –2008 period due, for example, to Conservation and Demand Management. The minimal amount of weather normalization and the constant retail energy assumption could potentially lead to forecasting errors.

- a. Please file a data table for the historical years 2002 to 2006 (and for the year 2007 if the actual values are available) that shows:
 - i. The actual retail energy (kWh) for each customer class in each year,

RESPONSE:

The following table outlines the actual retail energy (kWh) for each customer class for 2002 to 2006.

Customer Class	2002	2003	2004	2005	2006
Residential	134,772,689	137,538,000	136,303,616	144,724,830	139,960,236
GS < 50 kW	65,267,007	64,851,585	65,494,939	66,635,465	63,242,003
GS > 50 kW	138,361,916	142,885,583	146,981,638	144,362,624	174,720,116
Sentinel Lights	304,353	309,564	303,660	306,916	342,469
Streetlights	2,793,818	3,461,352	3,497,643	3,409,153	3,060,430
USL	231,982	471,986	406,396	406,396	406,396
Total	341,731,765	349,518,070	352,987,892	359,845,384	381,731,650

- ii. The weather normalized retail energy (kWh) for each customer class in each year (where, for the customer classes that BPI has identified as weather sensitive, the weather conversion of the actual load to the weather normalized load using a normalization factor for that year and not rely on results for any other year),

RESPONSE:

The following table outlines the weather normalized retail energy (kWh) for each customer class for 2002 to 2006. The classes that have been identified as weather sensitive are the Residential, GS < 50 kW and GS > 50 kW classes.

Customer Class	2002	2003	2004	2005	2006
Residential	131,619,008	136,602,742	136,480,811	142,640,792	141,037,930
GS < 50 kW	63,739,759	64,410,594	65,580,082	65,675,914	63,728,966
GS > 50 kW	135,124,247	141,913,961	147,172,714	142,283,802	176,065,461
Sentinel Lights	304,353	309,564	303,660	306,916	342,469
Streetlights	2,793,818	3,461,352	3,497,643	3,409,153	3,060,430
USL	231,982	471,986	406,396	406,396	406,396
Total	333,813,167	347,170,199	353,441,306	354,722,974	384,641,652

iii. The viii) the values of the weather normalization factors used,

RESPONSE:

The values of the weather normalization factors are shown below

2002	2003	2004	2005	2006
97.66%	99.32%	100.13%	98.56%	100.77%

iv. The customer count for each class in each year,

RESPONSE:

The customer/connection count for each class for 2002 to 2006 is provided in the following table.

Customer Class	2002	2003	2004	2005	2006
Residential	15,197	15,385	15,640	15,905	16,123
GS < 50 kW	2,181	2,144	2,132	2,107	2,098
GS > 50 kW	150	166	160	159	163
Sentinel Lights	389	380	400	400	400
Streetlights	3,750	3,749	3,800	3,800	3,050
USL	50	51	51	51	51
Total	21,717	21,875	22,183	22,422	21,885

v. The retail normalized average use per customer for each class in each year based on the weather corrected kWh data in item ii above, and

RESPONSE:

The retail normalized average use per customer for each class in each year based on the weather corrected kWh data in item ii. Above, is outlined in the following table:

Customer Class	2002	2003	2004	2005	2006
Residential	8,661	8,879	8,726	8,968	8,748
GS < 50 kW	29,225	30,042	30,760	31,170	30,376
GS > 50 kW	900,828	854,903	919,829	894,867	1,080,156
Sentinel Lights	782	815	759	767	856
Streetlights	745	923	920	897	1,003
USL	4,640	9,255	7,969	7,969	7,969

vi. As a footnote to the table, the source(s) of the weather correction factors.

RESPONSE:

In order to prepare this application BPI and its advisors researched various weather normalization methods and concluded that there were limited resources available in the

industry to prepare a cost effective weather normalization forecast which would reflect the characteristics of BPI. However, in order to prepare the recent cost allocation study, BPI retained Hydro One, as most other distributors in the province did, to weather normalize the 2004 volumes by rate class. From the documentation provided by Hydro One the following summarizes the weather normalization process used in the cost allocation study.

“Weather correction is a statistical process designed to remove the impact of abnormal or extreme weather conditions from historical load data. Normal weather data is defined to be data that is based on the average weather conditions experienced over the last 31 years. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year. The weather correction method is applicable to the total utility load as well as by rate class.”

Hydro One was approached to conduct a weather normalized forecast for the 2008 Test Year but the team of staff that had been used to prepare the weather normalized information for the cost allocation study were no longer available. In addition, the IESO was approached to prepare a weather normalized forecast but they also did not have the resources. Other options were pursued but the cost of preparing the weather normalized forecast was unreasonable. BPI then decided that a simplistic approach could be produced and still be effective and cost effective.

BPI believes that the method of using the 2004 weather normalized data as base data in the application to produce the weather normal forecast for 2008 is the most reasonable approach considering the 2004 weather normalized values reflect 31 years of average weather conditions. In the view of BPI, at the time the Application was prepared the only improvement that could have been made to the process would be to include 2005 and 2006 actual data in the 31 year average but it is expected this would not significantly change the 2004 weather normalized results and the costs of developing 2005 and 2006 data would outweigh the benefits.

However, in order to respond to this interrogatory BPI reviewed the responses of Halton Hills Hydro to the interrogatories in respect of its 2008 forward test year rate application (EB-2007-0696). In its December 21, 2007 response to question 17(a)(iii) in the second round of OEB Staff Interrogatories, Halton Hills Hydro used weather normalized data from the IESO website to develop weather conversion factors to address an interrogatory similar to this one. BPI has used these same factors to respond to this interrogatory. However, it is BPI’s view that using these factors to produce weather normalized data would be inferior to the method used in the Application, as it does not reflect specific rate class characteristics of BPI.

b. Please file a data table for the 2002 to 2008 period that:

- i. Utilizes the retail normalized average use per customer values for each class in each year obtained in (a)(v) above for the historical years 2002 to 2006;
- ii. Includes 2007 and 2008 actuals/projections for the retail normalized average use per customer values (where, for each of the weather-sensitive classes, this is based on trends in the data) for each class; and

- iii. Includes a footnote to the table, for each of the weather sensitive classes that describes in detail the trend analysis performed in ii above.

RESPONSE:

Table 8.7-b.i outlines the weather corrected average kWh/Customer values for the years 2002 to 2008 for the rate classes that are weather sensitive.

Table 8.7-b.i

Customer Class	2002	2003	2004	2005	2006	2007	2008
Residential	8,974	8,705	8,548	8,999	8,643	8,774	8,774
GS<50 kW	47,177	39,170	39,818	41,022	39,990	41,435	41,435
GS>50 kW	1,325,866	1,349,545	1,458,645	1,453,421	1,456,867	1,408,869	1,408,869

Note: The values for 2007 and 2008 were determined using the average for the years 2002 to 2006. The average was chosen, as there did not appear to be a good trend line in the numbers.

- c. Please file an updated version of the historical/forecast table in exhibit 3/Tab 2/Schedule 2 page 5, Table 3.2.2-4, utilizing the weather corrected data determined in b) above.

RESPONSE:

A version of Exhibit 3/Tab 2/Schedule 2 page 5, Table 3.2.2-4 using weather corrected average kWh/Customer values determined above is provided in Table BSI 8.7-c below.

Table BSI 8.7-c

		Historical Actual	Historical Board Approved	Historical Actual Weather Corrected	Bridge Year - Estimated	Bridge Year Weather Corrected	Test Year Weather Corrected
		2006	2006	2006	2007	2007	2008
Residential	#	32,877	32,108	32,877	33,287	33,287	33,818
	kWh	283,166,279	272,046,217	284,157,207	292,054,005	292,054,005	296,715,234
GS<50 kW	#	2,577	2,461	2,577	2,638	2,638	2,675
	kWh	97,811,277	97,287,108	103,053,433	109,302,098	109,302,098	110,857,439
GS>50 kW	#	407	391	407	408	408	413
	kWh	590,877,017	576,070,695	592,944,766	574,789,584	574,789,584	581,382,008
	kW	1,447,706	1,442,700	1,452,772	1,408,290	1,408,290	1,424,442
USL	#	460	523	460	435	435	435
	kWh	2,184,751	2,717,245	2,192,396	2,213,573	2,213,573	2,213,573
Sentinel	#	788	769	788	788	788	788
	kWh	555,133	574,675	555,133	538,038	538,038	538,038
	kW	1,850	1,916	1,850	1,793	1,793	1,793
Street Lights	#	9,520	8,762	9,520	9,773	9,773	10,056
	kWh	6,975,374	6,269,378	6,975,374	7,182,035	7,182,035	7,389,775
	kW	21,299	19,077	21,299	21,930	21,930	22,564
Standby	#	1	0	1	1	1	1
	kWh	2,724,185	n/a	2,724,185	2,078,025	2,078,025	2,078,025
	kW	26,265	n/a	26,265	23,403	23,403	23,403

9 LOSS FACTORS:

9.1 Ref:

Exhibit 4/Tab 2/Schedule 8 page 1

Exhibit 1/Tab 1/Schedule 2, Appendix A, page 2

Tariff of Rates and Charges, effective May 1, 2006, pages 3 & 4 (RP-2005-0020, EB-2005-0342)

Exhibit 4/Tab 2/Schedule 8 page 1 provides a calculation of actual distribution loss factors (DLF) for 2002 to 2006 and the proposed DLF, total loss factors (TLF) and Supply Facility Loss factor (SFLF) for 2008.

Exhibit 1/Tab 1/Schedule 2, Appendix A, page 2 provides the proposed TLF for 2008. The Tariff of Rates and Charges, Effective May 1, 2006, pages 3 & 4 (RP-2005-0020, EB-2005-0342) provides the approved TLF for 2006.

- a. In the 1st reference, please confirm if the figures provided in row H titled “Distribution Loss Adjustment Factor” for years 2002 to 2006 are the approved TLF figures related to secondary metered customers greater than 5, 000 kW for the respective years:
 - i. If this is correct, please re-word the row title.
 - ii. If this is not correct, please explain the purpose of the row H figures as distribution loss adjustment factors are addressed in row G. Please also explain the calculation method used to obtain the row H figures.

RESPONSE: i and ii

Accompanying these responses, in Attachment N, is a revised version of the Loss Adjustment Factor Calculation provided in Exhibit 4, Tab 2, Schedule 8, page 1. 2002 to 2004 are identical to Schedule 10-5 of the 2006 rate application. The Total Loss Factor for secondary metered customers <5000 kW reflects the 3.70% loss factor that was stated in Exhibit 4, Tab 2, Schedule 9. The revised table should now reflect the correct information in rows G and H.

- b. Please provide the loss factors in rows G and H of Exhibit 4/Tab 2/Schedule 8 page 1 with 4 decimal places rather than 2 decimal places.

RESPONSE:

This has been completed. Please refer to Attachment N.

- c. In light of the downward trend of BPI’s DLF as shown in row G in Exhibit 4/Tab 2/Schedule 8 page 1:

- i. Please explain the rationale for proposing that the TLF for 2008 for secondary metered customers <5,000 kW be 1.0409 rather than some lower factor such as 1.0370 which is the approved TLF for 2006.

RESPONSE:

The Total Loss Factor for 2008 for secondary metered customers < 5,000 kW is now 1.0370. Please refer to Attachment N.

- ii. Please describe any steps that are contemplated to sustain the downward trend of DLF.

RESPONSE:

BPI plans to continue reducing system losses through voltage conversion projects and system optimization. BPI's current plan is to complete voltage conversion from 4.16 kV to 27.6 kV by 2013. When designing system infrastructure projects, and subsequently operating the distribution system, BPI utilizes system-modeling software and good engineering practice to ensure that components of the distribution system are optimally sized and configured to minimize distribution losses. In addition to this, BPI uses a loss evaluation formula where the results of the calculation are used in the determination of the successful bidder when purchasing transformers for the system ensuring that BPI is purchasing transformers that are robust and less likely to experience losses. Such system optimization sustains the current downward trend in distribution loss factor.

9 COST ALLOCATION

Revenue Offset – Revenue from the Embedded Distributor

10.1 Ref: Exhibit 1/Tab 1/Schedule 12

- a. Please provide a brief description of BPI's facilities that are used totally or in part by the embedded distributor Brant County Power Inc.

RESPONSE:

There are three, 27.6 KV BPI feeders that are partially used to feed Brant County Power embedded load:

1. PM1 – from Powerline MTS
2. M25 – from Brantford TS
3. M27 – from Brantford TS

- b. Please provide a history, beginning in 2004 if applicable, of energy delivered to Brant County Power Inc. as an embedded distributor.

RESPONSE:

The yearly energy delivered to Brant County Power for 2004 to 2006 is provided in Table 10.1.b. BPI uses the energy values from its billing system. The data values may be found in columns D and P of the BPI Spreadsheet referred to in response to interrogatory 8.1.

Table 10.1.b

	2004	2005	2006
kWh	76,359,678	74,284,928	73,543,262
kW	167,071	163,253	160,356

- c. Please provide information on revenue received from Brant County Power Inc. as an embedded distributor.

RESPONSE:

No revenue has been received from Brant County Power Inc. as an embedded distributor. For a more detailed explanation, please refer to OEB Staff Interrogatory Response 10.3 b.

- d. Please confirm that any revenue from Brant County Power Inc. is used as a revenue offset, to determine the base revenue requirement to be collected from BPI's distribution customers, and indicate how that calculation is made in this application.

RESPONSE:

No revenue has been received from Brant County Power Inc.

10.2 Ref: Exhibit 8/Tab 1/Schedule 2

Please file the “rolled-up” public version of Run 2 of the Informational cost allocation model EB-2007-0001 as an official part of the record of this application. The hard copy reply needs to include only the Manager’s Summary, input tables (Sheet 13-18), and output tables Sheets O1 and O2. The electronic reply should include all worksheets.

RESPONSE:

Please note that the reference to sheets 13-18 in the question should be to I3-I8. Printouts of cost allocation Run 2 public file sheets I3-I8 and O1 and O2 are provided in hard copy form as Attachment O to these responses. The electronic version of the model that accompanies these responses includes all worksheets.

**10.3 Ref: Exhibit – Informational Filing EB-2007-0001/Sheet O1
Revenue to Cost Summary worksheet**

- a. Please describe the nature of the costs that are allocated to the Embedded Distributor customer category by BPI in its Informational filing, which add up to a class revenue requirement of approximately \$300,000 in the Informational Filing.

RESPONSE:

The nature of the costs that are allocated to the Embedded Distributor customer category in the Cost Allocation Informational Filing are listed below.

USoA Account	Accounts	Expense Type	Embedded Distributor
5405	Supervision	General & Administration	\$494
5410	Community Relations - Sundry	General & Administration	\$1,145
5420	Community Safety Program	General & Administration	\$362
5515	Advertising Expense	General & Administration	(\$3)
5605	Executive Salaries and Expenses	General & Administration	\$4,060
5610	Management Salaries and Expenses	General & Administration	\$3,226
5615	General Administrative Salaries and Expenses	General & Administration	\$9,181
5620	Office Supplies and Expenses	General & Administration	\$3,928
5630	Outside Services Employed	General & Administration	\$694
5635	Property Insurance	General & Administration	\$387
5645	Employee Pensions and Benefits	General & Administration	\$2,174
5650	Franchise Requirements	General & Administration	\$1,125
5655	Regulatory Expenses	General & Administration	\$2,179
5660	General Advertising Expenses	General & Administration	\$353
5665	Miscellaneous General Expenses	General & Administration	\$12,972
5670	Rent	General & Administration	\$4,676
5675	Maintenance of General Plant	General & Administration	\$539
5680	Electrical Safety Authority Fees	General & Administration	\$78
6105	Taxes Other Than Income Taxes	General & Administration	\$3,782
6205	Donations	General & Administration	\$81
5315	Customer Billing	Customer Related Cost	\$1
5705	Amortization Expense - Property, Plant, and Equipment	Depreciation & Amortization	\$55,005
5710	Amortization of Limited Term Electric Plant	Depreciation & Amortization	\$2,395
5005	Operation Supervision and Engineering	Distribution Cost	\$3,551
5010	Load Dispatching	Distribution Cost	\$205
5012	Station Buildings and Fixtures Expense	Distribution Cost	\$2,757
5014	Transformer Station Equipment - Operation Labour	Distribution Cost	\$200
5015	Transformer Station Equipment - Operation Supplies & Expenses	Distribution Cost	\$59
5020	Overhead Distribution Lines and Feeders - Operation Labour	Distribution Cost	\$24
5025	Overhead Distribution Lines & Feeders - Operation Supplies & Expenses	Distribution Cost	\$531
5040	Underground Distribution Lines and Feeders - Operation Labour	Distribution Cost	\$31
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Distribution Cost	\$150
5085	Miscellaneous Distribution Expense	Distribution Cost	\$3,464
5105	Maintenance Supervision and Engineering	Distribution Cost	\$9,075
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Distribution Cost	\$75
5114	Maintenance of Distribution Station Equipment	Distribution Cost	\$1,042
5120	Maintenance of Poles, Towers and Fixtures	Distribution Cost	\$7,225
5125	Maintenance of Overhead Conductors and Devices	Distribution Cost	\$11,833
5135	Overhead Distribution Lines and Feeders - Right of Way	Distribution Cost	\$12,595
5145	Maintenance of Underground Conduit	Distribution Cost	\$889
5150	Maintenance of Underground Conductors and Devices	Distribution Cost	\$2,579
6110	Income Taxes	PLS Input	\$38,956
6005	Interest on Long Term Debt	Interest	\$39,815

- b. Considering that the revenue to cost ratio for the Embedded distributor class is 5.84% in the informational filing, virtually all of the apparent revenue in 2004 was an allocation of Miscellaneous Revenue which may in actuality have been collected from all the other customer groups assumed in the model. Please describe any studies or other steps that BPI has taken since to ensure that is distribution customers are treated fairly relative to the embedded distributor. In particular, has BPI sought approval of rates to be paid by the Embedded Distributor class for the wheeling service proved through its facilities?

RESPONSE:

After the 2008 Rate Order, BPI intends to charge the Embedded Distributor the GS>50 kW distribution rate to ensure that BPI's customers are treated fairly. This was also stated in Exhibit 3, Tab 2, Schedule 6, page 2 of the Application. Please note that the correct period is the 2008 Test Year and not the 2007 Test Year as indicated at that page of the Application.

10 RATE DESIGN

Issue 11.1 Streetlighting

11.1 Ref: Exhibit 8/Tab 1/ Schedule 2/ page 2 Exhibit 9/Tab 1/Schedule 9 Appendix A page 12

- a. Please provide the justification for increasing the distribution rates for Street lighting by only the same percentage as all other classes, considering that it has a revenue to cost ratio of less than 37% and that the total bill impact for Street lighting in the application is – 15.3%

RESPONSE:

All percentage allocations between classes remained the same. Cost allocation was not taken into consideration at the time of filing, for the reasons set out in Exhibit 8, Tab 1, Schedule 2, page 2 and 3.

- b. Please provide an alternative set of revenue to cost ratios, in which rates and revenues from Street lighting are increased to yield a revenue to cost ratio of 70%, and revenue is decreased by an equal amount from one or more of the classes that have a ratio above 100%.

RESPONSE:

When the Street Lighting revenue to cost ratio is increased to 70% and the full adjustment is allocated to the GS>50 class, the GS>50 kW class revenue to cost ratio decreases to 138.3%. Although this response illustrates the results of allocating the adjustment in the Street Lighting ratio to only the GS>50 class, BPI may reallocate among other rate classes when BPI considers cost allocation-related adjustments in future years.

Issue 11.2 Retail Transmission Service Rates

**11.2 Ref: Exhibit 1/Tab 1/Schedule 12
 Exhibit 9/Tab 1/Schedule 3 page 1**

Please provide a description of how the changed cost of wholesale transmission delivered to the Brantford Transformer Station pursuant to the Retail Transmission Service rates described in Exhibit 9, and how the changed cost will be reflected in the Applicant’s settlement with the Embedded Distributor.

RESPONSE:

The Ontario Uniform Transmission Rate Order is reflected in the Retail Transmission Rate by reducing the Retail Transmission rates by more than they would have been reduced prior to the rate order.

<u>Current Retail Transmission Rates</u>	Network	Connection
Residential	\$0.0069	\$0.0059
General Service Less Than 50 kW	\$0.0062	\$0.0052
General Service Greater Than 50 kW	\$2.1137	\$1.7879
Street Lights	\$1.9512	\$1.6505
Sentinel Lights	\$1.9740	\$1.6698
Unmetered Scattered Load	\$0.0062	\$0.0052

Retail Transmission rates proposed prior to the Ontario Uniform Transmission Rate Order EB-2007-0759:

<u>Proposed Retail Transmission Rates</u>	Network	Connection
Residential	\$0.0071	\$0.0055
General Service Less Than 50 kW	\$0.0064	\$0.0048
General Service Greater Than 50 kW	\$2.1841	\$1.6526
Street Lights	\$2.0162	\$1.5256
Sentinel Lights	\$2.0397	\$1.5435
Unmetered Scattered Load	\$0.0064	\$0.0048

Retail Transmission rates after the issuance of the Ontario Uniform Transmission Rate Order EB-2007-0759:

<u>Proposed Retail Transmission Rates</u>	Network	Connection
Residential	\$0.0058	\$0.0051
General Service Less Than 50 kW	\$0.0052	\$0.0045
General Service Greater Than 50 kW	\$1.7828	\$1.5443
Street Lights	\$1.6457	\$1.4257
Sentinel Lights	\$1.6649	\$1.4423
Unmetered Scattered Load	\$0.0052	\$0.0045

The Embedded Distributor is being billed the GS> 50 kW network and connection rates. This is currently the case and will continue going forward.

11 DEFERRAL AND VARIANCE ACCOUNTS

12.1 Ref: Exhibit 5/Tab 1/Schedule 2 page 1 & 2 Exhibit 5/Tab 1/Schedule 3

- a. Please identify the specific dates for the opening balance, carrying charges, net accruals, adjustments and ending balance columns referred to in this exhibit.

RESPONSE:

The opening balances in this exhibit are the December 31, 2006 ending balances adjusted for the 2006 EDR allocations to account 1590 – Recovery of Regulatory Asset Balances, and the change in carrying charge calculations from the cash method to the accrual method as directed by OEB staff during their review of regulatory assets. The carrying charges, net accruals and adjustments reflect the projected activity from January 1, 2007 to April 30, 2008. The ending balances are the projected April 30, 2008 balances.

- b. Please provide allocations and rate order calculations, by individual account, for regulatory deferral and variance accounts being requested for disposition.

RESPONSE:

Accompanying these responses as Attachment P is a copy of the BPI DVAD model. This will provide details of the totals being allocated by account to the individual rate classes, and also indicates which of the deferral and variance accounts are not being disposed of.

At the fifth of six pages in Attachment P, the model gives a breakdown of the rate riders by individual account.

**12.2 Ref: Exhibit 1/Tab 1/Schedule 5 pages 4-5
Exhibit 5/Tab 1/Schedule 2&3**

BPI is requesting disposition of its deferral and variance accounts as at April 30, 2008.

- a. Please provide, for each deferral and variance account, the balances including principal and interest as at December 31, 2006 plus interest from January 1, 2008 to April 30, 2008

RESPONSE:

Please refer to the DVAD model in Attachment P. The sixth of six pages provides the breakdown of the rate riders by individual account. The column headed Dec 31/06 P+I plus Jan 1/07 to Apr 30/08 Interest provides the total for December 31, 2006 P+I and the interest earned on that principal from January 1, 2007 to April 30, 2008. BPI has assumed that OEB staff made a typographical error and were in fact requesting the interest from January 1, 2007 and not 2008 as they had indicated (this would tie into the request for part b)

- b. Please provide allocations and rate rider calculations, by individual account, using balances as at December 31, 2006 plus interest from January 1, 2007 to April 30, 2008.

RESPONSE:

Please refer to the DVAD model in Attachment P. The sixth of six pages provides the breakdown of the rate riders by individual account.

- c. Exh5/Tab1Sch2/Pg1&2 does not state the date of the balances nor does it differentiate between accounts that are proposed to be disposed and those that are not to be disposed. Please revise this schedule to detail which accounts will be cleared and the time period that the schedule refers to.

Note: Please provide the volume used (kWh, kW, customers, etc.) when calculating the rate riders – please refer to Interrogatory 12.2 and 12.3.

RESPONSE:

The opening balances in the pages referred to in the question are the December 31, 2006 ending balances adjusted for the 2006 EDR allocations to account 1590 – Recovery of Regulatory Asset Balances, and the change in carrying charge calculations from the cash method to the accrual method as directed by OEB staff during their review of regulatory assets. The carrying charges, net accruals and adjustments reflect the projected activity from January 1, 2007 to April 30, 2008. The ending balances are the projected April 30, 2008 balances.

Please see Exh5/Tab1/Sch2/Pg1&2 in Attachment Q. [Calculation of Balances by Account]

**12.3 Ref: Exhibit 1/Tab 1/Schedule 5 page 4
Exhibit 5/Tab 1/Schedule 3 page 3**

The APH states that carrying charges are not permitted in accounts 1565 – CDM Expenditures and Recoveries and 1566 – CDM Contra Account after February 28, 2005. However from the calculation of deferral and variance account balances by account in Exhibit 5/Tab 1/Schedule 2 pages 1 & 2, it is not clear whether carrying charges are incurred on the accounts after this date.

- a. Is BPI calculating carrying charges on these accounts after February 28, 2005

RESPONSE:

No, BPI is not calculating any carrying charges on these accounts after February 28, 2005. In fact, BPI never recorded any carrying charges on these accounts as the original plan was to spend all available funding on CDM programs.

- b. If yes, please restate the balances on the attached continuity schedule spreadsheet in interrogatory 12.8 and Exhibit 5/Tab 1/Schedule 2

RESPONSE:

N/A

**12.4 Ref: Exhibit 1/Tab 3/Schedule 2 Appendicies A & B
Exhibit 5/Tab 1/Schedule 2 pages 1-2**

The accounting guidelines in the December 2005 FAQ #3 of the APH require that an accounting entry in account 1565 is offset by an entry in Account 1566. In the 2007 and 2008 pro forma financial statements and in Exhibit 5/Tab 1/Schedule 2 pages, the balances of Account 1565 do not equal the balance in Account 1566. Please explain why.

RESPONSE:

Account 1565 was used to track the CDM costs for the programs relating to the 3rd Tranche of MARR. Offsetting entries were made to account 1566 to balance.

In the 2006 EDR, BPI received a rate rider for incremental CDM programs. This rate was effective May 1, 2006 to April 30, 2007. Account 1565 was used to track the difference between what was spent on the new CDM programs and what was collected from customers through rates. Offsetting entries were not required to the 1566 account.

BPI believes that the CDM funding approved by the OEB in the 2006 EDR was intended to be cost recovery of CDM expenses. As a result, BPI calculated the difference between CDM monies collected and those expended and recorded this variance in 1565. This enabled BPI to treat this one time funding as a pass through amount similar to RSVA variances. The use of 1566 as a contra was not deemed appropriate in this circumstance as to do so would have resulted in BPI reporting a return on these CDM activities for surplus funds collected. This was not the intent of the rate order, which only provided for the recovery of costs incurred. Consequently, no contra entries were recorded.

Therefore, the balance in 1566 represents amount that remains from the 3rd Tranche of MARR CDM funding.

12.5 Ref: Exhibit 5/Tab 1/Sch 1 page 8

In the 2006 EDR, BPI requested disposition of the balance of account 1571 based on the unadjusted 2004 balance. Subsequent to the 2006 EDR Decision and Order BPI had an independent review on their accounts and reallocations were made that affected the balance of this account.

- a. Please provide a schedule detailing all the accounts adjusted to support the restatement of account 1571.

RESPONSE:

These accounts are identified in the Excel spreadsheet provided in response to question 12.5 (e) below (items are identified as “b”).

- b. Please explain in detail the reasons for this adjustment.

RESPONSE:

At the time of market deregulation, BPI did not have sufficient systems in place to differentiate between pre-market and post-market opening consumption. During 2005, a detailed analysis was done to determine the correct split. Although the net impact of the changes between account 1571 and the Retail Settlement Variance Accounts (RSVA) was zero, BPI considered it necessary to accurately reflect the account balances in these areas.

- c. Were there any other accounts adjusted from 2006 EDR approved balances. Please explain the reasons for these adjustments.

RESPONSE:

Accounts 1580 Retail Settlement Variance Account – Wholesale Market Service and 1582 Retail Settlement Variance Account – One Time Wholesale Market Service were also adjusted from 2006 EDR approved balances. These accounts were adjusted to reflect the correct posting of the IMO bills from May 2002 to December 31, 2004. Again, although the net impact of the changes between account 1580 and 1582 was zero, BPI considered it necessary to accurately reflect the account balances in these areas.

- d. What is the regulatory precedent for the Board approving these prior period adjustments?

RESPONSE:

BPI is not aware of a regulatory precedent for approving these prior period adjustments. Nevertheless, with the passage of time and the increase in knowledge and understanding of the

regulatory environment, it was determined that the calculations for the deferral and variance accounts in the past were not as accurate as possible. BPI has made continuous improvement to its systems to ensure all calculations are correct. BPI believes that it should make every attempt to correctly reflect the balances of the deferral and variance accounts and as a result felt the prior years balances needed to be adjusted.

The adjustments ultimately did not change any of the balances in the totals of the 2006 EDR deferral and variance accounts, but they do ensure that BPI's records are as accurate as possible in this regard. BPI therefore submits that the OEB should approve these prior period adjustments.

- e. Please provide a schedule detailing all adjustments that were made to any of the 2006 EDR approved balances.

RESPONSE:

The requested schedule accompanies these responses as Attachment R.

12.6 Ref: Exhibit 5/Tab 1/Schedule 1 pages 8-9

BPI is requesting that the definition of Account 1592 be expanded to record such items as the impacts to PILs and taxes arising from non discretionary changes in generally accepted accounting principles (GAAP) or in changes in the provisions of the APH. There are also other changes requested.

- a. What is the regulatory precedent for the collection of these costs in this deferral account?

RESPONSE:

The non-discretionary transition of Canadian GAAP to the International Financial Reporting Standards (IFRS) could affect the level of PILs paid. Such third party-initiated changes to PILs will have the same impact on BPI as statutory changes to the applicable Income Tax Acts. Any variance in PILs recoveries attributable to statutory changes is currently allowed to be collected in this account.

- b. What is the justification for the changes to this account?

RESPONSE:

The Accounting Standards Board has determined that all Publicly Accountable Enterprises shall move to IFRS beginning in 2011. There are also certain exemptions previously available to rate regulated operations, which have been removed under the current Canadian GAAP effective January 2009.

Currently the level of PILs payable is determined by the provisions of the current Federal and Ontario Income Tax Acts as adjusted by provisions of the Electricity Act. Typically, the determination of taxable income under those statutes begins with accounting income determined by Canadian GAAP. Significant uncertainty exists over the impact of these significant developments in Canadian accounting standards as such changes may directly affect the calculation of taxable income.

It is a significant extraordinary event for the national accounting standards to be replaced. It is BPI's understanding that this is the first time in Canadian history that the country is adopting a new set of financial reporting standards.

At this time, the OEB, the Ministry of Finance and the Canada Revenue Agency have yet to determine whether these new reporting standards will be adopted within the scope of their respective statutory responsibilities. Furthermore, specific transitional measures are provided for when a country adopts IFRS. These transitional matters have yet to be finalized for the transition in Canada. As BPI has no direct ability to predetermine the impacts of this change on its PILs obligation, it cannot accurately forecast what, if any, adjustments may be required on its PILs revenue requirement. As a result, BPI has concluded that these non-discretionary

accounting changes will have the same impact on BPI as future statutory Income Tax changes and thus should be treated in the same way.

Current statutory changes impacting PILs obligations are fully accounted for in the Deferred PILs account 1592. Amending the definition to provide for any PILs impacts resulting from the adoption of IFRS or other significant non-discretionary change in accounting standards would be consistent with the concept of the current definition of account 1592. That is, changes in PILs solely attributable to rule changes, are deferred for future disposition. BPI submits that to the extent that the movement to IFRS or adoption of other non-discretionary accounting policies impacts the level of PILs obligations anticipated, these differences should be recorded in the variance account in a comparable manner to statutory changes. Put simply, BPI has no more control in influencing these non-discretionary changes as it does with respect to tax policy changes.

c. What are the journal entries to be recorded?

RESPONSE:

BPI's Application proposes the net change in PILs obligations directly attributable to the impacts of implementing IFRS or other non-discretionary accounting standards would be reflected in the deferral account. Once the impact of new accounting standards on BPI's PILs obligation is determined, any related deviations to the PILs paid not included in the existing revenue requirement will be recorded in the variance account as follows:

- In the case where the introduction of new accounting standards directly results in actual PILs payments that are lower than those provided for in the approved revenue requirement – i.e. over recovery of PILs:
 - Dr 4080 Distribution Revenue
 - Cr 1592 PILs & Tax Variances

- In the case where the introduction of new accounting standards directly results in actual PILs payments that are higher than those provided for in the approved revenue requirement – i.e. under recovery of PILs:
 - Dr 1592 PILs & Tax Variances
 - Cr 4080 Distribution Revenue

In addition, the account would accrue carrying charges in a fashion consistent with other variance accounts.

d. When does BPI plan to ask for its disposition?

RESPONSE:

It is contemplated that the request for disposition would be included at the next scheduled full cost of service application when the distribution rates will be rebased unless such variances become material in which case BPI may seek earlier disposition.

e. How does BPI plan to allocate this amount by rate class?

RESPONSE:

BPI would allocate this amount in proportion to the total distribution revenue contributed by the various rate classes during the taxation year in which such variances were accumulated.

f. Are these costs known? If yes, please identify the costs.

RESPONSE:

The only costs that are being contemplated are actual PILs over- or under-recoveries directly attributable to the change in the accounting framework. The magnitude of such amounts is not determinable at this time as the impact of the new accounting standards on PILs obligations has yet to be determined. This is the case as the OEB, Ministry of Finance and Canada Revenue Agency have yet to communicate a position on how they will address any impacts from these accounting changes on their respective statutory responsibilities.

g. If not, what would be the basis of the approval to record these amounts in this deferral account?

RESPONSE:

The approval would require BPI to reconcile the PILs recoveries required after the introduction of non discretionary accounting changes to the estimated PILs recoveries contained in this Application. The adjustments to the deferral account would be limited to those items on this reconciliation that were directly affected by the change in accounting or statutory changes to income taxes. Deviations resulting from general business activities or business performance would not result in an entry to the variance account.

For example, if spare parts totaling \$100,000 currently reflected as inventory e.g. distribution system switches, were required to be capitalized under IFRS, the impact would be determined as follows:

Current Treatment – no tax implications as such inventory items are reflected as working capital with the exception of spare meters and transformers.

New Accounting Treatment – Other spare parts will be reflected in Property Plant and Equipment. This notional reclassification to capital assets will increase the balance of Undepreciated Capital Cost resulting in additional Capital Cost Allowance of \$4,000 per year – ½ year rule provides an additional \$2,000 tax deduction in the first year. At the effective tax rate of 33.5%, the PILs Recovery revenue requirement will be overstated by \$2,000 x 33.5% or \$670.

BPI's entry would reflect the following over recovery of PILs:

Dr. 4080 Distribution Revenues	\$670
Cr 1592 PILs Variance	\$670

- h. What new or additional information is available, since the original filing this application that would improve the Board's ability to make a decision to approve the recording of these costs or fees in this deferral account?

RESPONSE:

The objectives of requesting approval to record these costs and fees in this deferral account are threefold:

1. The definition change would cover all non-discretionary accounting changes that affect PILs expenses, and not only IFRS. Accounting standards change every year in the normal course.
2. The Accounting Standards Board has indicated that any new accounting standards introduced prior to 2011 will be done in a fashion consistent with the IFRS to avoid changing them again in 2011. Therefore, some early changes before 2011, which could affect PILs, are possible.
3. Although BPI anticipates that it will be rebasing again in 2011, in the event of any policy decisions by the government or by the OEB that would prevent rebasing in 2011, or in the event of consolidation activity that may result in an extension of the period prior to BPI's next rebasing, BPI will have a mechanism to provide for the future recovery/return of PILs variances created by non discretionary changes in accounting standards.

On February 13, 2008 the Canadian Accounting Standards Board confirmed that the use of International Financial Reporting Standards (IFRS) would be required for publicly accountable profit-oriented enterprises beginning in 2011. Although the OEB has not addressed this issue from a rate making perspective, these new requirements will be mandatory for the preparation of general purpose audited financial statements which are typically used as the starting point for the preparation of PILs returns.

There is considerable publicly available information on the pending introduction of IFRS. The Accounting Standards Board and most of the international accounting firms have publicly available publications on the implications of IFRS based on their experience in other jurisdictions that have already made the change. Ernst & Young has produced a publication called “Converting to IFRS – An analysis of implementation issues”. In this document, Ernst & Young identifies that utilities are one of the industry sectors that will be affected. BPI suggests that a review of some of this material will provide a greater appreciation of the extent of some of these changes, many of which could affect the measurement of taxable income.

Given BPI’s preliminary analysis of publicly available information on the introduction of IFRS, BPI notes that the following activities would be undertaken in order to implement the new accounting standards in 2011:

- In 2008, Financial statements need to provide qualitative analysis of the impacts of IFRS;
- In 2009, Financial statements need to provide quantitative analysis of the impacts of IFRS; and
- In 2010, continue with GAAP for 2010 reporting but need 2010 IFRS comparatives when 2011 reports are prepared.

12.7 Ref: Exhibit 5/Tab 1/Schedule 3 pages 1-3

BPI stated that its Low Voltage Variance is captured in account 1551 on Exhibit 5/Tab 1/Schedule 3. The account descriptions for deferral and variance accounts on this schedule did not list which accounts were used to capture this variance before May 1, 2006 and after May 1, 2006.

- a. Should Account 1550 in Exhibit 5/Tab 1/ Schedule 3 page 1 be used instead of Account 1551 for the Low Voltage Variance Account?

RESPONSE:

Yes, account 1550 should be used; this appears to be an oversight on the schedule.

- b. For low voltage costs from Hydro One before May 1, 2006, what account was used?

RESPONSE:

Low voltage costs from Hydro One before May 1, 2006 were recorded to account 1586 based on the OEB December 9, 2004 Decision.

- c. What account did BPI use after May 1, 2006 what account was used?

RESPONSE:

Low Voltage costs were not incurred from Hydro One after May 1, 2006. BPI purchased the embedded lines from Hydro One in October 2005.

BPI used account 1550 to record Low Voltage recoveries from its customers through the 2006 EDR approved rate rider.

12.8 Ref: Exhibit 5/Tab 1/Schedule 3

BPI is requesting disposition of regulatory variance accounts in this exhibit. Most of the totals do not agree to totals reported to the Board under element 2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31, 2006. Please provide the necessary information in the attached excel spreadsheet continuity schedule for all regulatory assets and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on Exhibit 5/Tab 1/Schedule 3. Please note that forecasting principal transactions beyond December 31, 2006 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

RESPONSE:

Please see Attachment R.

BPI has filled in the OEB spreadsheet as required to agree to the totals on Schedule 2 Opening Balance. As there were no amounts indicated on Schedule 3, BPI assumes the OEB was referring to Schedule 2

Opening principal balances for January 1, 2005 differ from the 2006 EDR filed balances as detailed in BPI's response to OEB Staff IR 12.5. These adjustments related to the split between pre-market and RSVA consumption at May 1, 2006 as well as correcting the coding of the IMO bills between WMS and One-Time WMS

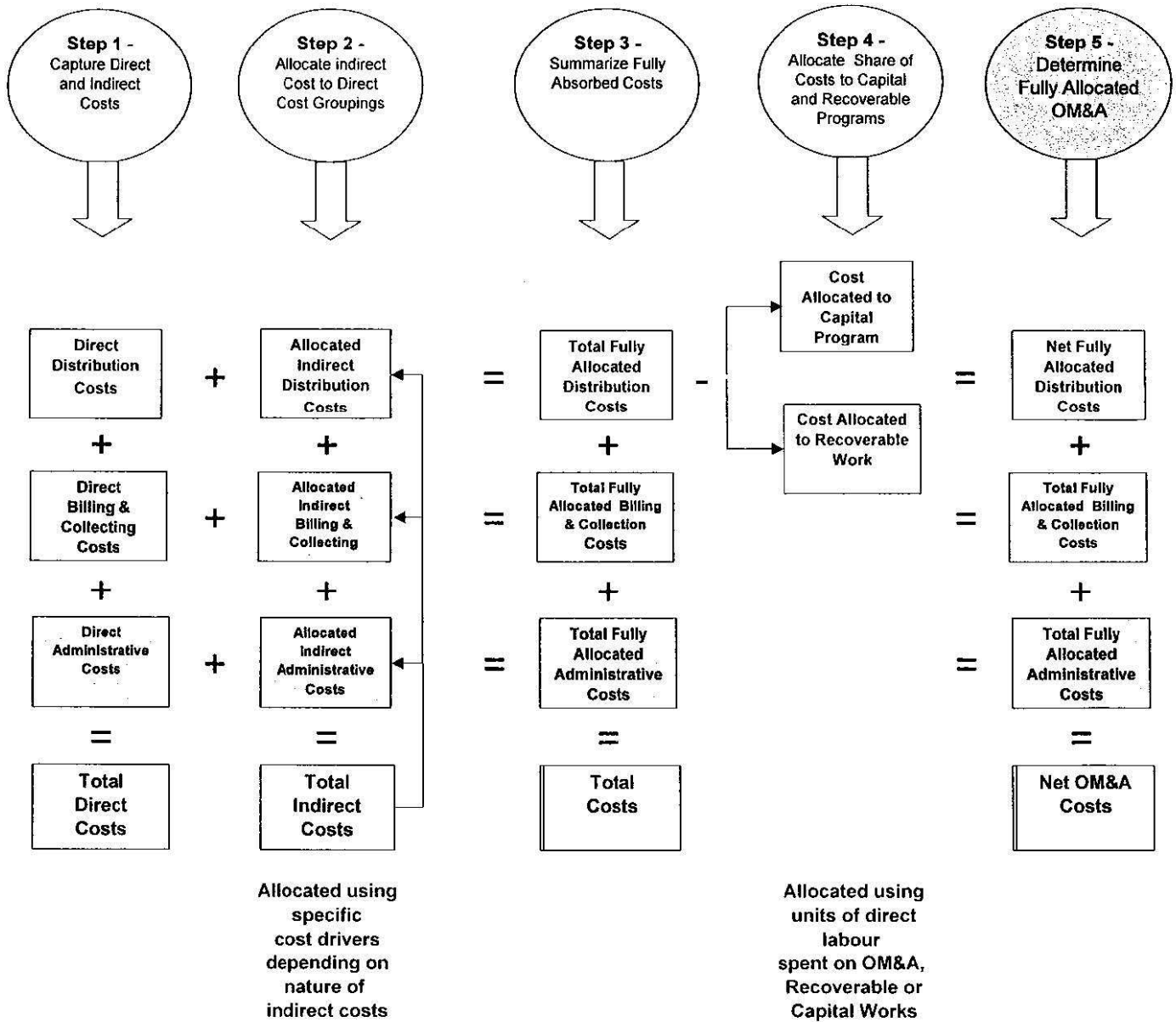
For the Adjustments during 2005 – instructed by Board – these relate to the 10% write down of transition costs as required on the 2006 EDR

For the Adjustments during 2006 – other – these relate to a reallocation for the cheque received from Hydro One for their second phase of regulatory asset disbursements.

ATTACHMENT A

REFERENCE: OEB STAFF QUESTION 1.1b

**BRANTFORD POWER INC.
ILLUSTRATION OF CAPITALIZATION POLICY COST ALLOCATION PROCESS**



ATTACHMENT B

REFERENCE: OEB STAFF QUESTION 3.1b

BRANTFORD POWER INC.
2008 EDR INTERROGATORIES
OEB Q3.1b

	2002	2003	2004	2005	2006	2007 Bridge	2008 Test
I Net Income	2,602,166	535,061	90,512	1,387,701	1,916,630	1,039,007	2,425,568
II Actual Return on Equity portion of Rate Base (%) (Approved Rate Base)	11.08%	2.28%	0.39%	5.91%	6.82%	3.70%	7.40%
Actual Return on Equity portion of Rate Base (%) (Actual Rate Base)	10.01%	2.08%	0.35%	4.39%	5.98%	3.07%	7.40%
III Allowed Return on the Equity portion of Rate Base (%)	6.59%	6.59%	6.59%	9.88%	9.00%	9.00%	8.68%
IV Retained Earnings	554,349	1,089,410	2,906,412	4,294,113	6,210,743	6,749,750	8,675,318
V Dividends to Shareholders	-	-	-	-	-	500,000	500,000
VI Sustained Capital Expenditures excluding smart meters	info not available	info not available	info not available	info not available	2,500,171	2,343,409	2,195,984
VII Development Capital Expenditures excluding smart meters	info not available	info not available	info not available	info not available	3,033,666	2,919,195	2,890,119
VIII Operations Capital Expenditures	info not available	info not available	info not available	info not available	266,010	315,000	235,000
IX Smart Meters Capital Expenditures	-	-	-	-	-	60,000	140,000
X Capital Expenditures (Identify)	info not available	info not available	info not available	info not available	105,991	200,000	190,000
XI Total Capital Expenditures excluding Smart Meters	2,484,370	2,098,740	2,929,226	11,253,858	5,387,232	5,811,260	5,433,102
Total Capital Expenditures including Smart Meters	2,484,370	2,098,740	2,929,226	11,253,858	5,387,232	5,871,260	5,573,102
XII Depreciation	1,925,441	1,969,970	2,157,977	2,497,700	2,771,699	3,030,907	3,274,650
XIII CWIP	-	-	47,076	386,336	-	-	-
XIV Number of Customer additions by class							
Residential	info not available	426	640	486	491	202	531
GS<50	info not available	423	35	65	126	1	42
Street Light	info not available	(481)	312	570	188	253	263
Sentinel	info not available	(112)	-	(20)	39	-	-
Unmetered Scattered Load	info not available	7	4	(37)	(47)	(4)	-
Total	-	263	991	1,064	797	452	856
XV Rate Base	51,971,049	51,467,371	52,297,109	63,202,125	64,136,712	67,709,859	70,179,031
Approved Rate Base	46,980,726	46,980,726	46,980,726	46,980,726	56,228,334	56,228,334	70,179,031

ATTACHMENT C

REFERENCE: OEB STAFF QUESTION 3.3 b & c

CONTINUITY STATEMENTS

	2006 Actual			2007 Bridge			2008 Test		
	Gross Asset Value	Accumulated Depreciation	Net Book Value	Gross Asset Value	Accumulated Depreciation	Net Book Value	Gross Asset Value	Accumulated Depreciation	Net Book Value
Land and Buildings									
1805-Land -Opening Balance	208,241	0	208,241	208,241	0	208,241	208,241	0	208,241
1805-Land -Additions	0	0	0	0	0	0	0	0	0
1805-Land -Depreciation	0	0	0	0	0	0	0	0	0
1805-Land -Adjustments	0	0	0	0	0	0	0	0	0
1805-Land -Closing Balance	208,241	0	208,241	208,241	0	208,241	208,241	0	208,241
Average	208,241	0	208,241	208,241	0	208,241	208,241	0	208,241
1806-Land Rights -Opening Balance	0	0	0	0	0	0	0	0	0
1806-Land Rights -Additions	0	0	0	0	0	0	0	0	0
1806-Land Rights -Depreciation	0	0	0	0	0	0	0	0	0
1806-Land Rights -Adjustments	0	0	0	0	0	0	0	0	0
1806-Land Rights -Closing Balance	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0
1905-Land -Opening Balance	0	0	0	0	0	0	0	0	0
1905-Land -Additions	0	0	0	0	0	0	0	0	0
1905-Land -Depreciation	0	0	0	0	0	0	0	0	0
1905-Land -Adjustments	0	0	0	0	0	0	0	0	0
1905-Land -Closing Balance	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0
1906-Land Rights-Opening Balance	0	0	0	0	0	0	0	0	0
1906-Land Rights-Additions	0	0	0	0	0	0	0	0	0
1906-Land Rights-Depreciation	0	0	0	0	0	0	0	0	0
1906-Land Rights -Adjustments	0	0	0	0	0	0	0	0	0
1906-Land Rights -Closing Balance	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0
1810-Leasehold Improvements-Opening Balance	0	0	0	0	0	0	0	0	0
1810-Leasehold Improvements-Additions	0	0	0	0	0	0	0	0	0
1810-Leasehold Improvements-Depreciation	0	0	0	0	0	0	0	0	0
1810-Leasehold Improvements -Adjustments	0	0	0	0	0	0	0	0	0
1810-Leasehold Improvements -Closing Balance	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV-Opening Balance	4,377,909	(109,448)	4,268,461	4,229,079	(237,908)	3,991,171	4,469,541	(373,692)	4,095,849
1815-Transformer Station Equipment - Normally Primary above 50 kV-Additions	91,632	0	91,632	0	0	0	0	0	0
1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation	0	(111,739)	(111,739)	0	(123,761)	(123,761)	0	(111,739)	(111,739)
1815-Transformer Station Equipment - Normally Primary above 50 kV-Adjustments	0	0	0	240,452	(12,023)	228,429	0	0	0
1815-Transformer Station Equipment - Normally Primary above 50 kV-Closing Balance	4,469,541	(221,187)	4,248,354	4,469,541	(373,692)	4,095,849	4,469,541	(485,431)	3,984,110
Average	4,423,725	(165,316)	4,258,408	4,349,310	(305,800)	4,043,510	4,469,541	(429,562)	4,039,980
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV-Opening Balance	140,683	(24,060)	116,623	140,683	0	140,683	140,683	(4,685)	135,998
1820-Distribution Station Equipment - Normally Primary below 50 kV-Additions	0	0	0	0	0	0	0	0	0
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation	0	(4,685)	(4,685)	0	(4,685)	(4,685)	0	(4,685)	(4,685)
1820-Distribution Station Equipment - Normally Primary below 50 kV-Adjustments	0	0	0	0	0	0	0	0	0
1820-Distribution Station Equipment - Normally Primary below 50 kV-Closing Balance	140,683	(28,745)	111,938	140,683	(4,685)	135,998	140,683	(9,370)	131,313
Average	140,683	(26,403)	114,281	140,683	(2,343)	138,341	140,683	(7,028)	133,656
Poles and Wires									
1830-Poles, Towers and Fixtures-Opening Balance	11,008,050	0	11,008,050	11,920,113	(100)	11,920,013	11,920,113	(243,615)	11,676,498
1830-Poles, Towers and Fixtures-Additions	2,508	0	2,508	0	0	0	100,762	0	100,762

1990-Other Tangible Property-Opening Balance	0	0	0	0	0	0	0	0	0
1990-Other Tangible Property-Additions	0	0	0	0	0	0	0	0	0
1990-Other Tangible Property-Depreciation	0	0	0	0	0	0	0	0	0
1990-Other Tangible Property-Adjustments	0	0	0	0	0	0	0	0	0
1990-Other Tangible Property-Closing Balance	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0
1995-Contributions and Grants - Credit-Opening Balance	(616,348)	24,654	(591,694)	(1,015,464)	65,272	(950,191)	(1,377,714)	124,695	(1,253,019)
1995-Contributions and Grants - Credit-Additions	(399,115)	0	(399,115)	(362,250)	0	(362,250)	(374,400)	0	(374,400)
1995-Contributions and Grants - Credit-Depreciation	0	40619	40,619	0	59,423	59,423	0	74,399	74,399
1995-Contributions and Grants - Credit-Adjustments	0	0	0	0	0	0	0	0	0
1995-Contributions and Grants - Credit-Closing Balance	(1,015,463)	65,273	(950,190)	(1,377,714)	124,695	(1,253,018)	(1,752,114)	199,094	(1,553,020)
Average	(70,948)	3,910	(67,038)	(1,168,589)	94,984	(1,101,605)	(1,564,914)	161,895	(1,403,020)
1809-Buildings and Fixtures - Credit-Opening Balance	1,192,568	(34,537)	1158031	1,192,568	(68,388)	1,134,180	1,192,568	(82,239)	1,110,329
1809-Buildings and Fixtures - Credit-Additions	0	0	0	0	0	0	0	0	0
1809-Buildings and Fixtures - Credit-Depreciation	0	(23,851)	(23,851)	0	(23,851)	(23,851)	0	(23,851)	(23,851)
1809-Buildings and Fixtures - Credit-Adjustments	0	0	0	0	0	0	0	0	0
1809-Buildings and Fixtures - Credit-Closing Balance	1,192,568	(58,388)	1134180	1,192,568	(82,239)	1,110,329	1,192,568	(106,090)	1,086,478
Average	1,192,568	(46,463)	1,146,106	1,192,568	(70,314)	1,122,255	1,192,568	(94,165)	1,098,404
1610-Miscellaneous Intangible Plant - Credit-Opening Balance	0	0	0	240,462	(12,023)	228,439	0	12,023	12,023
1610-Miscellaneous Intangible Plant - Credit-Additions	0	0	0	0	0	0	0	0	0
1610-Miscellaneous Intangible Plant - Credit-Depreciation	0	0	0	0	12,023	12,023	0	0	0
1610-Miscellaneous Intangible Plant - Credit-Adjustments	0	0	0	(240,462)	12,023	(228,439)	0	0	0
1610-Miscellaneous Intangible Plant - Credit-Closing Balance	0	0	0	0	12,023	12,023	0	12,023	12,023
Average	0	0	0	0	0	0	0	12,023	12,023
Total Opening Balance	62,011,452	(11,329,395)	50,682,057	67,740,363	(13,924,169)	53,816,195	73,518,425	(16,955,075)	56,563,350
Total Additions	5,905,836	0	5,905,836	5,778,063	0	5,778,063	5,311,157	0	5,311,157
Total Depreciation	0	(2,771,699)	(2,771,699)	0	(3,030,904)	(3,030,904)	0	(3,274,648)	(3,274,648)
Total Adjustments	(176,924)	176,924	0	0	0	0	0	0	0
Total Closing Balance	67,740,364	(13,924,170)	53,816,193	73,518,426	(16,955,073)	56,563,354	78,829,582	(20,229,723)	58,599,859

ATTACHMENT D

REFERENCE: OEB STAFF QUESTION 3.4c

BRANTFORD POWER CAPITAL BUDGET

DESCRIPTION	USofA	2007 BUDGET				2007 EST			
		2007 Budget CAPEX	Indirects	AFUDC	TOTAL	2007 Projected CAPEX	Indirects	AFUDC	TOTAL
NEW LINES AND EQUIPMENT									
NEW SERVICES (ROLL INS)	1855	227,988	152,515		380,503	194,473	125,668		320,141
NEW OH LINE EXTENSIONS	1830/1835	296,146	70,097	23,707	389,950	252,811	48,658	20,000	321,269
NEW U/G LINE EXTENSIONS	1840/1845	144,100	12,216		156,316	122,917	11,629		134,546
NEW OVERHEAD TRANSFORMERS	1850	123,600	15,463		138,763	80,800	7,234		87,234
NEW UNDERGROUND TRANSFORMERS	1850	176,575	21,662		198,237	500,000	40,191		540,191
LAND TRANSFER LINE EXTENSIONS - LOAD TRANSFERS NEW SUBDIVISIONS COST (# OF LOTS X \$2400) + TOWNHOMES COST (# OF TOWNHOMES X \$2100)	1830/1835	30,270	7,165		37,435	35,000	6,742		41,742
CIVIC SQUARE DOWNTOWN - PH3	1840/1845	1,270,000	107,850		1,377,850	700,000	66,227		766,227
CITYMTO RELOCATION OH	1840/1845	100,900	8,553		109,453	120,000	11,353		131,353
OAK PARK NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS(M12,M13)	1830/1835	299,250	70,832		370,082	625,000	101,126		626,126
JOHNSON RD RELOCATION	1830/1835	315,000	74,560		389,560	200,000	38,524		238,524
SCADA AND DISTRIBUTION AUTOMATION	1830/1835	63,000	14,912		77,912	60,000	11,557		71,557
	1980	210,000	-		210,000	200,000	-		200,000
		3,256,829	555,335	23,707	3,835,871	3,000,960	468,816	20,000	3,488,910
CONVERSION OF LINES FROM 48KV TO 27KV (Tier 2)									
POLES, TOWERS, & FIXTURES	1830	-	-		-	-	-		-
OH CONDUCTORS & DEVICES	1835	-	-		-	-	-		-
UG CONDUIT	1840	427,355	1,635		428,990	414,307	17,558		431,865
UG CONDUCTORS & DEVICES	1845	952,505	80,746		1,033,251	923,423	110,961		1,033,485
LINE TRANSFORMERS	1850	193,179	23,699		216,878	187,281	15,054		202,335
		1,573,039	106,080		1,679,119	1,525,011	142,674		1,667,685
REBUILD OF EXISTING LINES AND EQUIPMENT									
POLES, TOWERS, & FIXTURES	1830	-	-		-	-	-		-
OH CONDUCTORS & DEVICES	1835	-	-		-	-	-		-
UG CONDUIT	1840	170,240	40,295		210,535	170,240	40,069		210,309
UG CONDUCTORS & DEVICES	1845	-	-		-	-	-		-
LINE TRANSFORMERS	1850	-	-		-	-	-		-
		170,240	40,295		210,535	170,240	40,069		210,309
PROVISION FOR PURCHASE OF LINES FROM BRANT COUNTY POWER	1830/1835	-	-		-	-	-		-
UPGRADE AM/FM & GIS SYSTEM	1925	-	-		-	-	-		-
LAND (for new building)	1805	-	-		-	-	-		-
BUILDING	1808	-	-		-	-	-		-
SUBTOTAL		5,000,108	701,710	23,707	5,725,525	4,695,251	651,653	20,000	5,366,904
METERING									
METERING(METERS+INSTRUMENT TRANSFORMERS)	1860	336,369	88,368		424,736	336,369	16,635		353,004
WHOLESALE METERING (BRANTFORD TS)	1860	181,639	47,716		228,355	-	-		-
CONDO Sub-metering	1557/1860	100,000	-		100,000	100,000	4,946		104,946
SMART METERING	1557/1860	8,800	-		8,800	60,000	-		60,000
SUBTOTAL		626,808	136,086		762,894	496,369	21,581		517,950
VEHICLES	1930	300,000	-		300,000	300,000	-		300,000
TOOLS	1940	-	-		-	15,000	-		15,000
CAPITAL BUDGET - GROSS		5,926,916	837,796	23,707	6,788,419	5,506,620	673,234	20,000	6,199,854
RECOVERIES/CAPITAL CONTRIBUTIONS	1995	(628,813)	-		(628,813)	(362,250)	-		(362,250)
CAPITAL BUDGET - NET		5,298,103	837,796	23,707	6,159,606	5,144,370	673,234	20,000	5,837,604

SUMMARY by USofA:

Regulatory Asset - Smart Meter Capital Variance Acct	1557	108,600			108,600	60,000			60,000
Misc Intangible Plant	1610								
Land	1805								
Buildings	1808								
TS Equip >50kV	1815								
Distribution Station Equip < 50kV	1820								
Poles, Towers, & Fixtures	1830								
Overhead Conductors and Devices	1835	1,173,906	277,881	23,707	1,475,474	536,305	60,377	20,000	516,682
Underground Conduit	1840	427,355	1,635		428,990	706,545	168,289		892,844
Underground Conductors and Devices	1845	2,467,505	209,175		2,676,680	1,584,606	30,346		1,746,386
Line Transformers	1850	483,354	60,524		543,878	777,281	186,483		1,751,089
Services (Roll ins)	1855	227,988	152,515		380,503	194,473	125,668		839,761
Meters	1860	518,008	138,086		654,094	436,369	21,581		320,141
Computer Software	1925								457,950
Vehicles	1930	300,000			300,000	300,000			300,000
Tools	1940					15,000			15,000
Communication Equipment (ie truck radios)	1955								
Load Mgmt Controls	1970								
System Supervisory Equipment (SCADA)	1980	210,000			210,000	200,000			200,000
Contributions	1995	(628,813)			(628,813)	(362,250)			(362,250)
		5,189,333	837,796	23,707	6,050,836	5,084,370	673,234	20,000	5,777,604
Control = 0									
per Budget DIFF					6,050,806				6,050,807 (273,203)

BRANTFORD POWER CAPITAL BUDGET

DESCRIPTION	USofA	2008 BUDGET				2009			
		CAPEX	Indirects	AFUDC	TOTAL	CAPEX	Indirects	AFUDC	TOTAL
NEW LINES AND EQUIPMENT									
NEW SERVICES (ROLL IN'S)	1855	325,000	55,270		380,270	341,250	56,928		398,178
NEW OH LINE EXTENSIONS	1830/1835	150,000	55,860	18,000	223,860	157,500	52,660	56,389	266,549
NEW U/G LINE EXTENSIONS	1840/1845	225,000	33,151		258,151	235,250	35,905		272,156
NEW OVERHEAD TRANSFORMERS	1850	160,000	15,347		175,347	168,000	14,933		182,933
NEW UNDERGROUND TRANSFORMERS	1850	200,000	19,183		219,183	210,000	18,668		228,668
LAND TRANSFER LINE EXTENSIONS - LOAD TRANSFERS	1830/1835								
NEW SUBDIVISIONS COST (# OF LOTS X \$2400)+TOWNHOMES COST (# OF TOWNHOMES X \$2100)	1840/1845	950,000	137,323		1,067,323	976,500	148,411		1,124,911
CIVIC SQUARE DOWNTOWN - PH3	1840/1845								
CITY/MTO RELOCATION OH	1830/1835	270,000	100,547		370,547	283,500	94,788		378,288
OAK PARK NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS(M12 M13)	1830/1835	250,000	93,099		343,099	282,500	87,767		350,267
JOHNSON RD RELOCATION	1830/1835								
SCADA AND DISTRIBUTION AUTOMATION	1880	190,000			190,000	199,500			199,500
		2,700,000	509,483	18,000	2,227,483	2,835,000	510,058	56,389	3,401,448
CONVERSION OF LINES FROM 48KV TO 27KV (Tier 2)									
POLES, TOWERS, & FIXTURES	1830	15,000	2,711		17,711	60,000	5,668		69,668
OH CONDUCTORS & DEVICES	1835	20,000	11,281		31,281	65,000	32,992		97,992
UG CONDUIT	1840	275,000	12,291		287,291	250,000	11,827		261,827
UG CONDUCTORS & DEVICES	1845	350,000	107,601		457,601	510,000	102,825		612,825
LINE TRANSFORMERS	1850	250,000	23,979		273,979	300,000	26,986		326,986
		1,110,000	157,864		1,267,864	1,185,000	183,777		1,368,777
REBUILD OF EXISTING LINES AND EQUIPMENT									
POLES, TOWERS, & FIXTURES	1830	70,000	12,652		82,652	73,500	11,843		85,343
OH CONDUCTORS & DEVICES	1835	110,000	62,046		172,046	115,500	58,524		174,124
UG CONDUIT	1840	-	-		-	-	-		-
UG CONDUCTORS & DEVICES	1845	-	-		-	-	-		-
LINE TRANSFORMERS	1850	-	-		-	-	-		-
		180,000	74,698		254,698	189,000	70,467		259,467
PROVISION FOR PURCHASE OF LINES FROM BRANT COUNTY POWER									
	1830/1835								
UPGRADE AM/FM & GIS SYSTEM									
	1925	220,000			220,000	50,000			50,000
LAND (for new building)									
BUILDING	1805					1,750,000			1,750,000
	1808								
SUBTOTAL		4,210,000	742,042	18,000	4,970,042	6,069,060	764,303	56,389	6,829,692
METERING									
METERING(METERS- INSTRUMENT TRANSFORMERS)	1860	338,000	109,371		447,371	181,500	4,560		186,060
WHOLESALE METERING (BRANTFORD T'S)	1860	25,000	8,090		33,090	400,000	10,050		410,050
CONDO Sub-metering	1557/1860	-	-		-	200,000	5,025		205,025
SMART METERING	1557/1860	140,000			140,000	4,200,000	101,350		4,301,350
SUBTOTAL		503,000	117,461		620,461	4,981,500	120,985		5,102,485
VEHICLES									
	1930	205,000			205,000	310,000			310,000
TOOLS									
	1940	30,000			30,000	30,000			30,000
CAPITAL BUDGET - GROSS		4,948,000	859,503	18,000	5,825,503	11,330,500	885,288	56,389	12,272,177
RECOVERIES/CAPITAL CONTRIBUTIONS									
	1955	(374,400)			(374,400)	(393,120)			(393,120)
CAPITAL BUDGET - NET		4,573,600	859,503	18,000	5,451,103	10,937,380	885,288	56,389	11,879,057

SUMMARY by USofA:

Regulatory Asset - Smart Meter Capital Variance Acct	1557	140,000			140,000	166,076			166,076
Misc Intangible Plant									
Land	1805					1,750,000			1,750,000
Buildings	1808								
TS Equip >50kV	1815								
Distribution Station Equip < 50kV	1820								
Poles, Towers, & Fixtures	1830	420,000	75,911		495,911	485,250	78,188		563,438
Overhead Conductors and Devices	1835	485,000	262,285	18,000	745,285	532,250	270,154	56,389	858,793
Underground Conduit	1840	844,500	28,811		873,311	638,080	29,675		697,755
Underground Conductors and Devices	1845	1,335,000	281,258		1,596,258	1,334,670	289,094		1,603,764
Line Transformers	1850	610,000	58,509		668,509	678,000	60,264		738,264
Services (Roll ins)	1855	325,000	55,270		380,270	341,250	56,928		398,178
Meters	1860	363,000	117,461		480,461	4,815,424	120,985		4,936,409
Computer Software	1925	220,000			220,000	50,000			50,000
Vehicles	1930	205,000			205,000	310,000			310,000
Tools	1940	30,000			30,000	30,000			30,000
Communication Equipment (ie truck radios)	1955								
Load Mgmt Controls	1970								
System Supervisory Equipment (SCADA)	1980	190,000			190,000	199,500			199,500
Contributions	1995	(374,400)			(374,400)	(393,120)			(393,120)
		4,433,600	859,503	18,000	5,311,103	10,775,304	885,288	56,389	11,712,981

Control = 0

pe= Budget

D=FF

BRANTFORD POWER CAPITAL BUDGET

DESCRIPTION	USofA	2010				2011			
		CAPEX	Indirects	AFUDC	TOTAL	CAPEX	Indirects	AFUDC	TOTAL
NEW LINES AND EQUIPMENT									
NEW SERVICES (ROLL INS)	1855	358,313	58,636	-	416,948	376,228	60,355	-	436,623
NEW OH LINE EXTENSIONS	1830/1835	165,375	55,869	58,143	279,387	173,644	63,865	28,709	266,218
NEW UG LINE EXTENSIONS	1840/1845	246,063	43,211	-	289,274	200,486	38,385	-	238,851
NEW OVERHEAD TRANSFORMERS	1850	176,400	76,928	-	253,328	185,220	16,956	-	202,216
NEW UNDERGROUND TRANSFORMERS	1850	220,500	21,158	-	241,658	231,525	21,245	-	252,770
LAND TRANSFER LINE EXTENSIONS - LOAD TRANSFERS	1830/1835	-	-	-	-	-	-	-	-
NEW SUBDIVISIONS COST (# OF LOTS X \$2400)+TOWNHOMES COST (# OF TOWNHOMES X \$2100)	1840/1845	1,025,325	166,207	-	1,191,532	1,076,591	158,658	-	1,235,249
CIVIC SQUARE DOWNTOWN - PH3	1840/1845	-	-	-	-	-	-	-	-
CITY/MTO RELOCATION OH	1830/1835	297,675	100,565	-	398,240	312,559	114,598	-	427,157
OAK PARK NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS(M12 M13)	1830/1835	275,625	93,115	-	368,740	289,406	106,109	-	395,615
JOHNSON RD RELOCATION	1830/1835	-	-	-	-	-	-	-	-
SCADA AND DISTRIBUTION AUTOMATION	1980	209,475	-	-	209,475	219,949	-	-	219,949
		2,976,750	552,687	58,143	3,587,580	3,125,588	580,051	28,709	3,734,348
CONVERSION OF LINES FROM 48KV TO 27KV (Tier 2)									
POLES, TOWERS, & FIXTURES	1830	48,000	7,817	-	55,817	-	-	-	-
OH CONDUCTORS & DEVICES	1835	52,000	26,656	-	78,656	-	-	-	-
UG CONDUIT	1840	200,000	10,063	-	210,063	-	-	-	-
UG CONDUCTORS & DEVICES	1845	425,900	91,251	-	517,151	-	-	-	-
LINE TRANSFORMERS	1850	250,000	23,988	-	273,988	-	-	-	-
		975,000	159,785	-	1,134,785	-	-	-	-
REBUILD OF EXISTING LINES AND EQUIPMENT									
POLES, TOWERS, & FIXTURES	1830	77,175	12,568	-	89,743	81,034	14,337	-	95,371
OH CONDUCTORS & DEVICES	1835	121,275	62,161	-	183,436	127,339	70,846	-	198,185
UG CONDUIT	1840	-	-	-	-	275,000	12,316	-	287,316
UG CONDUCTORS & DEVICES	1845	-	-	-	-	550,000	107,603	-	657,603
LINE TRANSFORMERS	1850	-	-	-	-	280,000	25,693	-	305,693
		198,450	74,760	-	273,210	1,313,373	230,796	-	1,544,170
PROVISION FOR PURCHASE OF LINES FROM BRANT COUNTY POWER	1830/1835	-	-	-	-	-	-	-	-
UPGRADE AM/FM & GIS SYSTEM	1925	50,000	-	-	50,000	50,000	-	-	50,000
LAND (for new building)	1805	-	-	-	-	-	-	-	-
BUILDING	1808	6,000,000	-	-	6,000,000	-	-	-	-
SUBTOTAL		10,200,200	787,232	58,143	11,045,575	4,488,960	810,849	28,709	5,328,518
METERING									
METERING(METERS+INSTRUMENT TRANSFORMERS)	1860	363,000	46,595	-	409,595	363,000	81,030	-	444,030
WHOLESALE METERING (BRANTFORD TS)	1860	12,000	1,534	-	13,534	12,000	2,579	-	14,879
CONDO Sub-metering	1557/1860	600,000	76,686	-	676,686	200,000	44,644	-	244,644
SMART METERING	1557/1860	127,000	-	-	127,000	-	-	-	-
SUBTOTAL		1,102,000	124,614	-	1,226,614	575,000	128,353	-	703,353
VEHICLES	1930	315,000	-	-	315,000	335,000	-	-	335,000
TOOLS	1940	30,000	-	-	30,000	30,000	-	-	30,000
CAPITAL BUDGET - GROSS		11,647,200	911,847	58,143	12,617,190	5,428,960	939,202	28,709	6,396,871
RECOVERIES/CAPITAL CONTRIBUTIONS	1985	(412,776)	-	-	(412,776)	(433,415)	-	-	(433,415)
CAPITAL BUDGET - NET		11,234,424	911,847	58,143	12,204,414	4,995,545	939,202	28,709	5,963,456

SUMMARY by USofA:

Regulatory Asset - Smart Meter Capital Variance Acct	1557	127,000	-	-	127,000	-	-	-	-
Misc Intangible Plant	1610	-	-	-	-	-	-	-	-
Land	1805	-	-	-	-	-	-	-	-
Buildings	1808	6,000,000	-	-	6,000,000	-	-	-	-
TS Equip >50kV	1815	-	-	-	-	-	-	-	-
Distribution Station Equip < 50kV	1820	-	-	-	-	-	-	-	-
Poles, Towers, & Fixtures	1830	494,513	80,534	-	575,046	469,838	82,950	-	551,788
Overhead Conductors and Devices	1835	542,613	278,268	58,143	879,024	515,143	286,606	28,709	830,458
Underground Conduit	1840	607,484	30,566	-	638,050	702,858	31,483	-	734,341
Underground Conductors and Devices	1845	1,290,804	277,166	-	1,567,970	1,456,199	285,481	-	1,744,680
Line Transformers	1850	646,900	62,072	-	708,972	696,745	83,834	-	760,579
Services (Roll Ins)	1855	358,313	58,636	-	416,948	376,228	60,355	-	436,623
Meters	1860	975,000	124,614	-	1,099,614	575,000	128,353	-	703,353
Computer Software	1925	50,000	-	-	50,000	50,000	-	-	50,000
Vehicles	1930	315,000	-	-	315,000	335,000	-	-	335,000
Tools	1940	30,000	-	-	30,000	30,000	-	-	30,000
Communication Equipment (ie truck radios)	1955	-	-	-	-	-	-	-	-
Load Mgmt Controls	1970	-	-	-	-	-	-	-	-
System Supervisory Equipment (SCADA)	1980	209,475	-	-	209,475	219,949	-	-	219,949
Contributions	1985	(412,776)	-	-	(412,776)	(433,415)	-	-	(433,415)
		11,107,424	911,847	58,143	12,077,414	4,995,545	939,202	28,709	5,963,456

Control = 0

per Budget
DIFF

BRANTFORD POWER CAPITAL BUDGET

DESCRIPTION	USoIA	2012				2013
		CAPEX	Indirects	AFUOC	TOTAL	BUDGET (excl. Indirects)
NEW LINES AND EQUIPMENT						
NEW SERVICES (ROLL INS)	1855	395,040	82,207		457,246	414,792
NEW OH LINE EXTENSIONS	1830/1833	182,326	65,575	28,981	276,882	191,442
NEW U/G LINE EXTENSIONS	1840/1845	273,489	36,953		310,452	287,163
NEW OVERHEAD TRANSFORMERS	1850	194,481	20,087		214,568	204,205
NEW UNDERGROUND TRANSFORMERS	1850	243,101	25,109		268,210	255,256
LAND TRANSFER LINE EXTENSIONS - LOAD TRANSFERS	1830/1835	-	-		-	-
NEW SUBDIVISIONS COST (# OF LOTS X \$2400)+TOWNHOMES COST (# OF TOWNHOMES X \$2100)	1840/1845	1,130,421	152,781		1,283,201	1,186,942
CIVIC SQUARE DOWNTOWN - PH3	1840/1845	-	-		-	-
CITY/MTO RELOCATION OH	1830/1835	328,187	118,036		446,222	344,596
OAK PARK NORTH INDUSTRIAL SERVICING AND LINE RELOCATIONS(M12,M13)	1830/1835	303,877	109,292		413,169	319,070
JOHNSON RD RELOCATION	1830/1835	230,946	-		230,946	242,493
SCADA AND DISTRIBUTION AUTOMATION	1960	-	-		-	-
		3,261,867	590,050	28,981	3,900,897	3,445,960
CONVERSION OF LINES FROM 416KV TO 27KV (Tier 2)						
POLES, TOWERS & FIXTURES	1830	-	-		-	25,000
OH CONDUCTORS & DEVICES	1835	-	-		-	35,000
UG CONDUIT	1840	-	-		-	190,000
UG CONDUCTORS & DEVICES	1845	-	-		-	270,000
LINE TRANSFORMERS	1850	-	-		-	230,000
		-	-		-	765,000
REBUILD OF EXISTING LINES AND EQUIPMENT						
POLES, TOWERS, & FIXTURES	1830	85,085	14,767		99,853	89,340
OH CONDUCTORS & DEVICES	1835	133,706	72,972		206,677	140,381
UG CONDUIT	1840	315,000	13,365		328,365	125,000
UG CONDUCTORS & DEVICES	1845	690,000	123,364		813,364	270,000
LINE TRANSFORMERS	1850	200,000	20,657		220,657	-
		1,423,791	245,125		1,668,916	624,721
PROVISION FOR PURCHASE OF LINES FROM BRANT COUNTY POWER	1830/1835	-	-		-	-
UPGRADE AM/FM & GIS SYSTEM	1925	50,000	-		50,000	-
LAND (for new building)	1805	-	-		-	-
BUILDING	1808	-	-		-	-
SUBTOTAL		4,755,658	835,175	28,981	5,619,814	4,770,691
METERING						
METERING/METERS+INSTRUMENT TRANSFORMERS)	1850	363,000	132,203		495,203	363,000
WHOLESALE METERING (BRANTFORD TS)	1860	-	-		-	-
CONDO Sub-metering	1557/1860	-	-		-	-
SMART METERING	1557/1860	-	-		-	-
SUBTOTAL		363,000	132,203		495,203	363,000
VEHICLES	1930	330,000	-		330,000	325,000
TOOLS	1940	30,000	-		30,000	30,000
CAPITAL BUDGET - GROSS		5,478,658	967,378	28,981	6,475,017	5,488,691
RECOVERIES/CAPITAL CONTRIBUTIONS	1995	(455,086)	-		(455,086)	(477,840)
CAPITAL BUDGET - NET		5,023,572	967,378	28,981	6,019,932	5,010,851

SUMMARY by USoIA:

Regulatory Asset - Smart Meter Capital Variance Acct	1557				
Misc Intangible Plant	1610	-	-	-	-
Land	1805	-	-	-	-
Buildings	1808	-	-	-	-
TS Equip >50kV	1815	-	-	-	-
Distribution Station Equip < 50kV	1820	-	-	-	-
Poles, Towers, & Fixtures	1830	492,280	85,438	28,981	577,119
Overhead Conductors and Devices	1835	540,500	295,204		835,704
Underground Conduit	1840	764,251	32,427		796,678
Underground Conductors and Devices	1845	1,644,659	294,046		1,938,705
Line Transformers	1850	637,582	85,852		723,435
Services (Roll ins)	1855	395,040	82,207		457,246
Meters	1860	363,000	132,203		495,203
Computer Software	1925	50,000	-		50,000
Vehicles	1930	330,000	-		330,000
Tools	1940	30,000	-		30,000
Communication Equipment (ie truck radios)	1955	-	-		-
Load Mgmt Controls	1970	-	-		-
System Supervisory Equipment (SCADA)	1980	230,946	-		230,946
Contributions	1995	(455,086)	-		(455,086)
		5,023,572	967,378	28,981	6,019,932

Control = 0

per Budget
DIFF

ATTACHMENT E

REFERENCE: OEB STAFF QUESTION 4.3d) i

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-law passed by the City on October 23, 2000 as By-law Number 156-2000.

→ copy ←

This Promissory Note is not assignable by the City without the consent of the Corporation.

DATED this 31st day of January 2006.

BRANTFORD POWER INC.

Per: Heather Wyatt H
Name: Heather Wyatt
Title: Secretary

Per: D Matthews
Name: Dave Matthews
Title: Chair

ATTACHMENT F

REFERENCE: OEB STAFF QUESTION 4.3g

ATTACHMENT G

REFERENCE: OEB STAFF QUESTION 4.3g

	2004	2005	2006	2007	2008
Debt Service Costs	2,177,025	2,305,573	1,877,509	1,898,867	2,098,380
Average Debt Outstanding	24,189,168	26,760,127	30,792,730	31,173,442	34,768,608
Effective Debt Rate	9.00%	8.62%	6.10%	6.09%	6.04%

ATTACHMENT H

REFERENCE: OEB STAFF QUESTION 4.3g

CAPITAL STRUCTURE

2006 Board Approved

Elements	\$ Million	Actual	Deemed	Cost Rate (%)	Return (%)
Long-term debt	32,898,168	59.50%	50.00%	6.10%	3.05%
Unfunded short-term debt	0	0		0	
Preference shares	0	0		0	
Common equity	22,437,505	40.50%	50.00%	9.00%	4.50%
Total	55,335,673	100%	100%		7.55%

2006 Actual

Elements	\$ Million	Actual	Deemed	Cost Rate (%)	Return (%)
Long-term debt	31,289,168	58.24%	50%	6.10%	3.05%
Unfunded short-term debt	0	0		0	
Preference shares	0	0		0	
Common equity	22,437,505	41.76%	50%	9.00%	4.50%
Total	53,726,673	100%	100%		7.55%

2007 Bridge

Elements	\$ Million	Actual	Deemed	Cost Rate (%)	Return (%)
Long-term debt	33,401,168	59.82%	50.00%	6.10%	3.05%
Unfunded short-term debt	0				
Preference shares	0				
Common equity	22,437,505	40.18%	50.00%	9.00%	4.50%
Total	55,838,673	100%	100%		7.55%

2008 Test

Elements	\$ Million	Actual	Deemed	Cost Rate (%)	Return (%)
Long-term debt	36,092,030	61.66%	49.33%	6.04%	2.98%
Unfunded short-term debt	0		4.00%	4.77%	0.19%
Preference shares	0				
Common equity	22,437,505	38.34%	46.67%	8.68%	4.05%
Total	58,529,535	100%	100%		7.22%

ATTACHMENT I

REFERENCE: OEB STAFF QUESTION 7.1a) i



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, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing. For more information on how to complete the return, see the *T2 Corporation - Income Tax Guide* (T4012).

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year. For more information on when and how to file T2 returns, refer to the Guide under the heading "Before you start."

Identification

Business Number (BN) **001** 86585 8773 RC0001

Corporation's name
002 BRANTFORD POWER INC.

Has the corporation changed its name since the last time we were notified? **003** 1 Yes 2 No

If Yes, do you have a copy of the articles of amendment? ... **004** 1 Yes 2 No

Address of head office
Has this address changed since the last time we were notified? **010** 1 Yes 2 No
(If Yes, complete lines 011 to 018)

To which tax year does this return apply?
Tax year start **060** 2006-01-01 Tax year end **061** 2006-12-31
YYYY MM DD YYYY MM DD

011 84 Market Square
012 P.O. Box 308
City Province, territory, or state
015 Brantford **016** ON
Country (other than Canada) Postal code/Zip code
017 **018** N3T 5N8

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? **063** 1 Yes 2 No
If Yes, provide the date control was acquired **065** YYYY MM DD

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? **020** 1 Yes 2 No
(If Yes, complete lines 021 to 028)

Is the corporation a professional corporation that is a member of a partnership? **067** 1 Yes 2 No

022 84 Market Square
023 P.O. Box 308
City Province, territory, or state
025 Brantford **026** ON
Country (other than Canada) Postal code/Zip code
027 **028** N3T 5N8

Is this the first year of filing after:
Incorporation? **070** 1 Yes 2 No
Amalgamation? **071** 1 Yes 2 No
If Yes, complete lines 030 to 038 and attach Schedule 24.

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
(If Yes, complete lines 031 to 038)

Has there been a windup of a subsidiary under section 88 during the current tax year? **072** 1 Yes 2 No
If Yes, complete and attach Schedule 24.

031 84 Market Square
032 P.O. Box 308
City Province, territory, or state
035 Brantford **036** ON
Country (other than Canada) Postal code/Zip code
037 **038** N3T 5N8

Is this the final tax year before amalgamation? **076** 1 Yes 2 No
Is this the final return up to dissolution? **078** 1 Yes 2 No

040 Type of corporation at the end of the taxation year
1 Canadian-controlled private corporation (CCPC) 4 Corporation controlled by a public corporation
2 Other private corporation 5 Other corporation (specify, below)
3 Public corporation

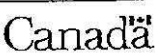
Is the corporation a resident of Canada? **080** 1 Yes 2 No If No, give the country of residence on line 081 and complete and attach Schedule 97.
081
Is the non-resident corporation claiming an exemption under an income tax treaty? **082** 1 Yes 2 No
If Yes, complete and attach Schedule 91.

If the type of corporation changed during the tax year, provide the effective date of the change **043** YYYY MM DD

If the corporation is exempt from tax under section 149, tick one of the following boxes:
035 1 Exempt under paragraph 149(1)(e) or (l)
2 Exempt under paragraph 149(1)(j)
3 Exempt under paragraph 149(1)(l)
4 Exempt under other paragraphs of section 149

Do not use this area
091 **092** **093** **094** **095** **096**
100

PLEASE KEEP FOR REFERENCE



Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each Yes response, attach to the T2 return the schedule that applies.

	Yes	Schedule
Is the corporation related to any other corporations?	<input checked="" type="checkbox"/>	9
Is the corporation an associated Canadian-controlled private corporation?	<input checked="" type="checkbox"/>	23
Is the corporation an associated Canadian-controlled private corporation that is claiming the expenditure limit?	<input checked="" type="checkbox"/>	49
Does the corporation have any non-resident shareholders?	<input type="checkbox"/>	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	<input type="checkbox"/>	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?	<input type="checkbox"/>	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	<input type="checkbox"/>	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	<input type="checkbox"/>	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	<input type="checkbox"/>	T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	<input type="checkbox"/>	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?	<input type="checkbox"/>	22
Did the corporation have any foreign affiliates during the year?	<input type="checkbox"/>	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal <i>Income Tax Regulations</i> ?	<input type="checkbox"/>	29
Has the corporation had any non-arm's length transactions with a non-resident?	<input type="checkbox"/>	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	<input checked="" type="checkbox"/>	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	<input type="checkbox"/>	
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	<input checked="" type="checkbox"/>	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; or gifts of cultural or ecological property?	<input type="checkbox"/>	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	<input type="checkbox"/>	3
Is the corporation claiming any type of losses?	<input type="checkbox"/>	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	<input type="checkbox"/>	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	<input type="checkbox"/>	6
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) is the corporation claiming the refundable portion of Part I tax?	<input type="checkbox"/>	7
Does the corporation have any property that is eligible for capital cost allowance?	<input checked="" type="checkbox"/>	8
Does the corporation have any property that is eligible capital property?	<input checked="" type="checkbox"/>	10
Does the corporation have any resource-related deductions?	<input type="checkbox"/>	12
Is the corporation claiming reserves of any kind?	<input type="checkbox"/>	13
Is the corporation claiming a patronage dividend deduction?	<input type="checkbox"/>	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	<input type="checkbox"/>	17
Is the corporation an investment corporation or a mutual fund corporation?	<input type="checkbox"/>	18
Was the corporation carrying on business in Canada as a non-resident corporation?	<input type="checkbox"/>	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	<input type="checkbox"/>	21
Is the corporation a non-resident-owned investment corporation claiming an allowable refund?	<input type="checkbox"/>	26*
Does the corporation have any Canadian manufacturing and processing profits?	<input type="checkbox"/>	27
Is the corporation claiming an investment tax credit?	<input type="checkbox"/>	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	<input type="checkbox"/>	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over \$10,000,000?	<input type="checkbox"/>	33/34/35
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	<input checked="" type="checkbox"/>	36
Is the corporation claiming a surtax credit?	<input type="checkbox"/>	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	<input type="checkbox"/>	38
Is the corporation claiming a Part I tax credit?	<input type="checkbox"/>	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?	<input type="checkbox"/>	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	<input type="checkbox"/>	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	<input type="checkbox"/>	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?	<input type="checkbox"/>	39
Is the corporation claiming a Canadian film or video production tax credit refund?	<input type="checkbox"/>	T1131
Is the corporation claiming a film or video production services tax credit refund?	<input type="checkbox"/>	T1177
Is the corporation subject to Part XIII.1 tax?	<input type="checkbox"/>	92*

* We do not print this schedule.

Attachments - continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	<input type="checkbox"/>	T1134-A
Did the corporation have any controlled foreign affiliates?	258	<input type="checkbox"/>	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over \$100,000?	259	<input type="checkbox"/>	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	<input type="checkbox"/>	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	<input type="checkbox"/>	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	<input type="checkbox"/>	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	<input type="checkbox"/>	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	<input type="checkbox"/>	T1174

Additional information

Is the corporation inactive?	280	1 Yes <input type="checkbox"/>	2 No <input checked="" type="checkbox"/>
Has the major business activity changed since the last return was filed? (enter Yes for first-time filers)	281	1 Yes <input type="checkbox"/>	2 No <input checked="" type="checkbox"/>
What is the corporation's major business activity? (Only complete if Yes was entered at line 281.)	282		
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283	1 Wholesale <input type="checkbox"/>	2 Retail <input type="checkbox"/>
Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.	284	Electricity Distribution	285 100.000 %
	286		287 %
	288		289 %
Did the corporation immigrate to Canada during the tax year?	291	1 Yes <input type="checkbox"/>	2 No <input checked="" type="checkbox"/>
Did the corporation emigrate from Canada during the tax year?	292	1 Yes <input type="checkbox"/>	2 No <input checked="" type="checkbox"/>

able income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFL.	300	7,005,402	A
Deduct: Charitable donations from Schedule 2	311		
Gifts to Canada, a province, or a territory from Schedule 2	312		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction from Schedule 43 *	325		
Non-capital losses of preceding tax years from Schedule 4	331		
Net capital losses of preceding tax years from Schedule 4	332		
Restricted farm losses of preceding tax years from Schedule 4	333		
Farm losses of preceding tax years from Schedule 4	334		
Limited partnership losses of preceding tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
	Subtotal		B
	Subtotal (amount A minus amount B) (if negative, enter "0")	7,005,402	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C plus amount D)	360	7,005,402	
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)		7,005,402	Z

s amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year			
Income from active business carried on in Canada from Schedule 7	400	7,005,402	A
Transferable income from line 360, minus 10/3 of the amount on line 632*, minus 3 times the amount on line 36**, and minus any amount that, because of federal law, is exempt from Part I tax	405	7,005,402	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

250,000	x	Number of days in the tax year in 2004	=	1
		Number of days in the tax year	365	
300,000	x	Number of days in the tax year in 2005 and in 2006	365	= 300,000 2
		Number of days in the tax year	365	
400,000	x	Number of days in the tax year after 2006	=	3
		Number of days in the tax year	365	
Add amounts at lines 1, 2, and 3				300,000 4
Business limit (see notes 1 and 2 below)				410 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 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 ***	117,795	D	=		E
				11,250			
Reduced business limit (amount C minus amount E) (if negative, enter "0")						425	F

Small business deduction

Whichever amount is the least A, B, C or F								G1
Amount G1	x	Number of days in the tax year before 2008	365	x	16.00 %	=		G2
		Number of days in the tax year	365					
Amount G1	x	Number of days in the tax year in 2008		x	16.50 %	=		G3
		Number of days in the tax year	365					
Amount G1	x	Number of days in the tax year after 2008		x	17.00 %	=		G4
		Number of days in the tax year	365					

Small business deduction – total of amounts G2, G3, and G4 430 G

(enter amount G on line 9)

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.
** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

***** Large corporations**

- The amount to be entered at line 415 is the total taxable capital employed in Canada minus \$10,000,000 x 0.225%, calculated on Schedule 33, Part 1.3 Tax On Large Corporations, Schedule 34, Part 1.3 Tax On Financial Institutions or Schedule 35, Part 1.3 Tax On Large Insurance Companies.
- If the corporation is not associated with any corporations in both the current and the preceding tax years, use the applicable schedule for the prior year. (Amount P in Part 6 of Schedule 33; Amount O in Part 6 of Schedule 34; Amount DD in Part 6 of Schedule 35)
- If the corporation is not associated with any corporations in the current tax year, but was associated in the preceding tax year, use the applicable schedule for the current year.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Accelerated tax reduction

Canadian-controlled private corporations throughout the taxation year that claimed the small business deduction

Reduced business limit (amount from line 425)	x	<u>300,000</u>	=	A
			line 4 above		<u>7,005,402</u>	B
Net active business income (amount from line 400) *					
Taxable income from line 360 minus 3 times the amount at line 636** on, and minus any amount that, because of federal law, is exempt from Part I Tax		<u>7,005,402</u>			C
Deduct:						
Aggregate investment income (amount from line 440)					D
Amount C minus amount D (if negative, enter "0")		<u>7,005,402</u>		<u>7,005,402</u>	E
Amount A, B, or E above, whichever is less					F
Amount Z from Part 9 of Schedule 27	x	<u>100 / 7</u>	=	G
Amount QQ from Part 13 of Schedule 27					H
Taxable resource income (amount from line 435)					I
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)					J
Amount on line 400, 405, 410, or 425 of the small business deduction, whichever is less					K
Total of amounts G, H, I, J, and K					L
Amount F minus amount L (if negative, enter "0")					M
Accelerated tax reduction – 7.00 % of amount M (enter amount N on line 637)					N

* If the amount at line 450 of Schedule 7 is positive, members of partnerships need to use Schedule 70 to calculate net active business income.
** Calculate the amount of foreign business income tax credit deductible at line 636 without reference to the corporate tax reductions under section 123.4.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)]		<u>435</u>			A
Amount A	x	Number of days in the tax year in 2004	x	2 % =	B
			Number of days in the tax year	365		
Amount A	x	Number of days in the tax year in 2005	x	3 % =	C
			Number of days in the tax year	365		
Amount A	x	Number of days in the tax year in 2006	x	5 % =	D
			Number of days in the tax year	365		
Amount A	x	Number of days in the tax year after 2006	x	7 % =	E
			Number of days in the tax year	365		
Resource deduction – total of amounts B, C, D, and E (enter amount F on line 10)				<u>438</u>	F

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360				<u>7,005,402</u>	A	
Amount Z1 from Part 9 of Schedule 27					B	
Amount QQ from Part 13 of Schedule 27					C	
Taxable resource income from line 435 above					D	
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)					E	
Amount on line 400, 405, 410, or 425, whichever is the least					F	
Aggregate investment income from line 440					G	
Amount used to calculate the accelerated tax reduction (amount M)					H	
Total of amounts B, C, D, E, F, G, and H					I	
Amount A minus amount I (if negative, enter "0")				<u>7,005,402</u>	J	
Amount J	<u>7,005,402</u>	x	Number of days in the tax year before 2008	<u>365</u>	x	7 % =	K1
			Number of days in the tax year	365			
Amount J	<u>7,005,402</u>	x	Number of days in the tax year in 2008	x	7.5 % =	K2	
			Number of days in the tax year	365			
Amount J	<u>7,005,402</u>	x	Number of days in the tax year in 2009	x	8 % =	K3	
			Number of days in the tax year	365			
Amount J	<u>7,005,402</u>	x	Number of days in the tax year after 2009	x	9 % =	K4	
			Number of days in the tax year	365			
General tax reduction for Canadian-controlled private corporations – total of amounts K1, K2, K3, and K4 (enter amount K on line 638)				<u>490,378</u>	K	

General tax reduction

Corporations other than a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation; and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the full tax rate of 38% (eg. deposit insurance company).

Taxable income from line 360				L
Amount Z1 from Part 9 of Schedule 27			M	
Amount QQ from Part 13 of Schedule 27			N	
Taxable resource income from line 435 above			O	
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)			P	
Total of amounts M, N, O, and P			▶	Q
Amount L minus amount Q (if negative, enter "0")				R
Amount R	x	Number of days in the tax year before 2008 Number of days in the tax year	365 x 7% =	S1
Amount R	x	Number of days in the tax year in 2008 Number of days in the tax year	365 x 7.5% =	S2
Amount R	x	Number of days in the tax year in 2009 Number of days in the tax year	365 x 8% =	S3
Amount R	x	Number of days in the tax year after 2009 Number of days in the tax year	365 x 9% =	S4
General tax reduction – total of amounts S1, S2, S3, and S4 (enter amount S on line 639)				S

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income	440	x	26 2 / 3 % =	A
(amount O from Part 1 of Schedule 7)				
Foreign non-business income tax credit from line 632				
Deduct:				
Foreign investment income	445	x	9 1 / 3 % =	B
(amount L from Part 2 of Schedule 7) (if negative, enter "0")				
Amount A minus amount B (if negative, enter "0")				
Taxable income from line 360 7,005,402				
Deduct:				
Amount on line 400, 405, 410, or 425, whichever is the least				
Foreign non-business income tax credit from line 632		x	25 / 9 =	
Foreign business income tax credit from line 636		x	3 =	
				7,005,402
				x 26 2 / 3 % = 1,868,107
Part I tax payable minus investment tax credit refund (line 700 minus line 780) 1,549,596				
Deduct: Corporate surtax from line 600 78,461				
Net amount 1,471,135 ▶ 1,471,135 E				
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least 450 F				

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the preceding 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 line 360 of 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 of Schedule 3		x 1 / 3 _____	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)		_____	

Part I tax

Base amount of Part I tax — 38.00 % of taxable income (line 360 or amount Z, whichever applies) **550** 2,662,053 A

C Corporate surtax calculation

Base amount from line A above 2,662,053 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) 700,540 2
 Investment corporation deduction from line 620 below 3
 Federal logging tax credit from line 640 below 4
 Federal qualifying environmental trust tax credit from line 648 below 5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360 a
 28.00 % of taxed capital gains b
 Part I tax otherwise payable c

(line A plus lines C and D minus line F)
 Total of lines 2 to 6 700,540 7

Net amount (line 1 minus line 7) 1,961,513 8

Corporate surtax

line 8 1,961,513 x 4 % x $\frac{\text{Number of days in the tax year before 2008}}{\text{Number of days in the tax year}} = \frac{365}{365} = \mathbf{600}$ 78,461 B

Recapture of investment tax credit from line OO in Part 17 of Schedule 31 **602** C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
 (If it was a CCPC throughout the tax year)

Aggregate investment income from line 440 i
 Taxable income from line 360 7,005,402

Deduct:

Amount on line 400, 405, 410, or 425, whichever is the least
 Net amount 7,005,402 ii

Refundable tax on CCPC's investment income — 6 2 / 3 % of whichever is less: amount i or ii **604** D

Subtotal (add lines A, B, C, and D) 2,740,514 E

Deduct:

Small business deduction from line 430 9

Federal tax abatement **608** 700,540

Manufacturing and processing profits deduction from amount BB or amount RR of 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**

Accelerated tax reduction from amount N **637**

Resource deduction from line 438 10

General tax reduction for CCPCs from amount K **638** 490,378

General tax reduction from amount S **639**

Federal logging tax credit from Schedule 21 **640**

Federal political contribution tax credit **644**

Federal political contributions **646**

Federal qualifying environmental trust tax credit **648**

Investment tax credit from Schedule 31 **652**

Subtotal 1,190,918 F

Part I tax payable — Line E minus line F (enter amount G on line 700) 1,549,596 G

Summary of tax and credits

Federal tax

Part I tax payable	700	1,549,596
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
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		1,549,596

Add provincial or territorial tax:

Provincial or territorial jurisdiction	750	Ontario	
(If more than one jurisdiction, enter "multiple" and complete Schedule 5)			
Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		1,549,596 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	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	
Allowable refund for non-resident-owned investment corporations from Schedule 26	804	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	
Balance (line A minus line B)		1,549,596 B

Refund code **894** Overpayment

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 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 1,549,596
Enclosed payment **898** 1,549,596

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

Certification

I, **950** D'Amboise Last name **951** Brian First name **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 further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2007-04-14 Date (yyyy/mm/dd) **956** (519) 759-4150 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 **959** Telephone number

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering 1 for English or 2 for French. 1 English / Anglais 2 Français / French
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français.

GENERAL INDEX OF FINANCIAL INFORMATION - GIF

Name of corporation BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year end Year Month Day 2006-12-31
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Balance sheet information

Account	Description	GIFI	Amount	Prior year
Assets				
	Total current assets	1599 +	22,547,934	19,998,155
	Total tangible capital assets	2008 +	67,740,365	62,011,453
	Total accumulated amortization of tangible capital assets	2009 -	13,924,168	11,329,395
	Total intangible capital assets	2178 +		
	Total accumulated amortization of intangible capital assets	2179 -		
	Total long-term assets	2589 +	4,701,335	6,756,999
	* Assets held in trust	2590 +		
	Total assets (mandatory field)	2599 =	81,065,466	77,437,212

Liabilities				
	Total current liabilities	3139 +	18,955,059	19,491,420
	Total long-term liabilities	3450 +	33,462,159	31,214,174
	* Subordinated debt	3460 +		
	* Amounts held in trust	3470 +		
	Total liabilities (mandatory field)	3499 =	52,417,218	50,705,594

Shareholder equity				
	Total shareholder equity (mandatory field)	3620 +	28,648,248	26,731,618

	Total liabilities and shareholder equity	3640 =	81,065,466	77,437,212
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Retained earnings				
	Retained earnings/deficit - end (mandatory field)	3849 =	6,210,743	4,294,113

* Generic item

GENERAL INDEX OF FINANCIAL INFORMATION - GIF1

Form identifier 125

Name of corporation BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year end Year Month Day 2006-12-31
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Income statement information

Description	GIFI
Operating name	0001
Description of the operation	0002
Sequence Number	0003 01

Account	Description	GIFI	Amount	Prior year
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Income statement information				
	Total sales of goods and services	8089 +	86,747,849	91,924,315
	Cost of sales	8518 -	72,220,464	78,083,275
	Gross profit/loss	8519 =	14,527,385	13,841,040
	Cost of sales	8518 +	72,220,464	78,083,275
	Total operating expenses	9367 +	11,239,678	12,507,130
	Total expenses (mandatory field)	9368 =	83,460,142	90,590,405
	Total revenue (mandatory field)	8299 +	87,905,944	92,792,594
	Total expenses (mandatory field)	9368 -	83,460,142	90,590,405
	Net non-farming income	9369 =	4,445,802	2,202,189

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 =	4,445,802	2,202,189
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Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975 -		
	Legal settlements	9976 -		
	Unrealized gains/losses	9980 +		
	Unusual items	9985 -		163,975
	Current income taxes	9990 -	2,529,172	650,513
	Deferred income tax provision	9995 -		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999 =	1,916,630	1,387,701

NOTES CHECKLIST

Corporation's name BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year end Year Month Day 2006-12-31
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- This schedule should be completed from the perspective of the person who prepared or reported on the financial statements. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? **095** 1 Yes 2 No

Is the accounting practitioner connected* with the corporation? **097** 1 Yes 2 No

* 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 accounting practitioner does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: **198**

Completed an auditor's report 1

Completed a review engagement report 2

Inducted a compilation engagement 3

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement** above, answer the following question:

Has the accounting practitioner expressed a reservation? **099** 1 Yes 2 No

Part 4 – Other information

Were notes to the financial statements prepared? **101** 1 Yes 2 No

If Yes, complete lines 102 to 107 below:

Are any values presented at other than cost? **102** 1 Yes 2 No

Has there been a change in accounting policies since the last return? **103** 1 Yes 2 No

Are subsequent events mentioned in the notes? **104** 1 Yes 2 No

Is re-evaluation of asset information mentioned in the notes? **105** 1 Yes 2 No

Is contingent liability information mentioned in the notes? **106** 1 Yes 2 No

Is information regarding commitments mentioned in the notes? **107** 1 Yes 2 No

Does the corporation have investments in joint venture(s) or partnership(s)? **108** 1 Yes 2 No

If Yes, complete line 109 below:

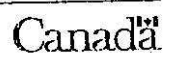
Are you filing financial statements of the joint venture(s) or partnership(s)? **109** 1 Yes 2 No

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Corporation's name BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year end Year Month Day 2006-12-31
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- 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*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements		1,916,630 A
Add:		
Provision for income taxes – current	101 2,529,172	
Interest and penalties on taxes	103 14,622	
Amortization of intangible assets	106 2,771,699	
Income or loss for tax purposes – joint ventures or partnerships	109 3,408	
Non-deductible meals and entertainment expenses	121 4,307	
Reserves from financial statements – balance at the end of the year	126 855,586	
Subtotal of additions	6,178,794	6,178,794
Other additions:		
Miscellaneous other additions:		
600 Change in regulatory assets	290 2,665,504	
Subtotal of other additions	199 2,665,504	2,665,504
Total additions	500 8,844,298	8,844,298
Deduct:		
Gain on disposal of assets per financial statements	401 24,441	
Capital cost allowance from Schedule 8	403 2,841,656	
Cumulative eligible capital deduction from Schedule 10	405 67,579	
Reserves from financial statements – balance at the beginning of the year	414 821,850	
Subtotal of deductions	3,755,526	3,755,526
Other deductions:		
Miscellaneous other deductions:		
Subtotal of other deductions	499 0	0
Total deductions	510 3,755,526	3,755,526
Net income (loss) for income tax purposes – enter on line 300 of the T2 return		<u>7,005,402</u>



General Rate Income Pool Workchart (CCPCs)

- Corporations that are Canadian-controlled private corporations (CCPC) or deposit insurance corporations (DIC) within the meaning of the federal *Income Tax Act* (ITA) can use this form to calculate the amount of the general rate income pool and the additions.
- Calculation of the additions to the general rate income pool is made in Part 3. Parts 3B and 3C are treated in a dynamic manner, with the result that this part will only be displayed if either one of the situations listed in Part 1 exists.
- According to the legislative proposals relating to dividend taxation, a CCPC or a DIC can pay an eligible dividend amount, during a taxation year, that is not in excess of its general income rate pool at the end of the year. If it exceeds this amount, it might be liable to pay additional tax on excessive eligible dividend designations as determined under the terms of Part III.1 of the ITA.
- The general rate income pool definition can be found in subsection 89(1) of the ITA.
- For more information, we refer you to the context-sensitive help as well as the *Notice of Ways and Means Motion to Implement Certain Provisions of the Budget Tabled in Parliament on May 2, 2006*, released on October 16, 2006, or any recent version of these provisions.

Part 1 – Eligibility to the various additions

Answer the following questions to determine the corporation's eligibility to 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?
3. If yes, 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 3A.

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 3B.

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 3B.
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 3C.

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 2.
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 3B.
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 3C.

Part 2 - Calculation of the general rate income pool (A - B)

A - General rate income pool at the end of the year before adjustment	6,213,546	A
B - Adjustment of the general rate income pool to take carrybacks into account	-	B
Closing balance of the general rate income pool	= 6,213,546	

Calculation of amount A

The general rate income pool at the end of the year before adjustment is determined based on the following formula:

• $A = C + 68\% (D - E - F) + G + H - I$

C - General rate income pool at the end of the preceding taxation year	+ 1,449,873	
2006 addition (calculated in section 3A)	+ 1,449,873	
Subtotal	= 1,449,873	C
D - Corporation's taxable income*	7,005,402	D
E - Small business deduction for the year		
Conversion factor	x 100 / 16	
Subtotal	=	E
F - Lesser of total investment's income or taxable income**	-	F
Subtotal (D-E-F)	= 7,005,402	
Nominal rate	x 68.00 %	
Subtotal	= 4,763,673	+ 4,763,673
G - Amounts received from other corporations		
i) Eligible dividends received by the corporation during the year		
Included in Schedule 3	+	
Not included in Schedule 3	+	
Subtotal	=	
ii) Deductible amounts under section 113 for the particular taxation year	+	
Subtotal (i)+ii)	=	G
H - Additions for corporations that become a CCPC's, that were formed as a result of an amalgamation or that wound-up a subsidiary.	+	H
Eligible dividends paid in the preceding year***		
i) Eligible dividends paid in its preceding taxation year	-	
ii) Excessive eligible dividends designations in its preceding taxation year	-	
Subtotal (i)-ii)	=	I
General rate income pool at the end of the year before adjustment	= 6,213,546	A

* If the corporation is a deposit insurance corporation, enter zero.

** If the corporation is not a CCPC, enter zero.

*** If the corporation has not changed status to become a CCPC.

Calculation of amount B

The general rate income pool to take carrybacks into account is determined based on the following formula:

• $B = 68\% (a - b)$

a) Total of the corporation's full rate taxable incomes for the preceding three taxation years determined without reference to any specified future tax consequences, for those preceding taxation years that arise in respect of the particular taxation year	-	
b) Total of adjusted corporation's full taxable incomes for those preceding years	-	
Subtotal	=	
Nominal rate	x 68.00 %	
Adjustment of the general rate income pool to take carrybacks into account	=	B

Part 3A - Calculation of the addition for the CCPCs in 2006 (A - B)

The addition to the general rate income pool applies to a corporation that was, or that would have been but for an election under subsection 89(11) (election not to be a CCPC), throughout its first taxation year that includes any part of January 1, 2006, a Canadian-controlled private corporation.

The term "full rate taxable income" is defined in subsection 123.4(1). In broad terms, the full rate taxable income correspond to the portion of the taxable income for the year that is not exempt from tax and that did not benefit from the various special effective rates.

The 2006 addition is determined based on the following calculation: 63% multiplied by the full rate taxable income for its taxation years that ended after 2000 and before 2006.

A - Taxable income and dividends received after 2000 and before 2006

Full rate taxable income		<u>2,301,385</u>	
Nominal rate	x	<u>63.00 %</u>	
		Subtotal =	<u>1,449,873</u>	
Total taxable dividends received from a connected payer corporation	+		
		Subtotal =	<u>1,449,873</u>	▶ <u>1,449,873</u> A

B - Taxable dividends paid after 2000 and before 2006

Total of the taxable dividends paid	-		<u> </u> B
				Addition for the CCPCs in 2006
(Carry this amount to line C of part 2 of the corporation's general rate income pool)				= <u>1,449,873</u>

Workchart for the 2006 addition (CCPCs)

Addition to the general rate income pool is determined under subsection 89(7) ITA. It applies to a corporation that was, or that would have been but for an election under subsection 89(11) (election not to be a CCPC), throughout its first taxation year that includes any part of January 1, 2006, a CCPC.

In order for the addition to be calculated properly in the general rate income pool, enter the required amounts, according to the type of corporation, for each of the corporation's taxation year that ended after 2000 and before 2006. If the corporation has more than one taxation year ending within the same calendar year, add the required amounts and carry the total over to the column corresponding to that year.

Section 1 corresponds to the full rate taxable income for corporations that are CCPCs. Section 2 corresponds to the full rate taxable income for corporations that are neither CCPCs nor investment corporations.

If, for a taxation year, the corporation is an investment corporation, a mortgage investment corporation (MIC) or a mutual funds corporation, do not enter anything in sections 1 and 2 in the columns corresponding to that year. Investment corporations have a full rate taxable income of zero.

Select this check box if you want to import amounts from the *Five Year Comparative Summary* into this workchart.

Note: Any amounts imported from the *Five Year Comparative Summary* should be reviewed to ensure that they reflect any reassessments received or other adjustments made subsequent to the filing of the original returns.

Taxation year(s) ending on	2001	2002	2003	2004	2005	Total
Part 1 – Corporations that are CCPCs (123.4(1)b) ITA						
Taxable income for the year (subtract line 370 from line 360 of Schedule 200)					2,301,385	
Minus amount giving entitlement to the deduction on manufacturing and processing profits (lesser of amounts V and Y from Part 9 of Schedule 27)						
Minus amount giving entitlement to the deduction for electrical energy and steam (amount QQ from Part 13 of Schedule 27)						
Minus taxable income from resources for the year (line 435 of Schedule 200)						
Minus amount giving entitlement to the credit union deduction (amount E from Part 3 of Schedule 17)						
Minus amount giving entitlement to small business deduction (lesser of amounts A, B and C of the "Small business deduction" section of Schedule 200)						
Minus total investment income (line 440 of Schedule 200)						
Minus amount giving entitlement to CCPC deduction under subsection 123.4(3) (accelerated tax reduction) (amount M of the "Accelerated tax reduction" section of Schedule 200).						
Total of the full rate taxable income for CCPCs					2,301,385	2,301,385

Part 2 – Corporations that are neither CCPCs nor investment corporations (123.4(1)a) ITA						
Taxable income for the year (subtract line 370 from line 360 of Schedule 200)						
Minus amount giving entitlement to the deduction on manufacturing and processing profits (lesser of amounts V and Y from Part 9 of Schedule 27)						
Minus amount giving entitlement to the deduction for electrical energy and steam (amount QQ from Part 13 of Schedule 27)						
Minus taxable income from resources for the year (line 435 of Schedule 200)						
Minus amount giving entitlement to the credit union deduction (amount E from Part 3 of Schedule 17)						
Total of the full rate taxable income for corporations that are neither CCPCs nor investment corporations						

Taxation year(s) ending on	2001	2002	2003	2004	2005	Total
Part 3 - Total deductible dividends under subsection 112 (1) received from a connected corporation						
Total taxable dividends received from a connected payer corporation						
Part 4 - Taxable dividends paid						
Taxable dividends paid included on line 460 of Schedule 3						
Other taxable dividends paid not included in Schedule 3						
Total taxable dividends paid						
Addition for CCPCs in 2006 (63% (Total of Part 1 + Total of Part 2) + Total of Part 3 - Total of Part 4) (if negative, enter "0")						1,449,873

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation: **BRANTFORD POWER INC.**
 Business Number: **86585 8773 RC0001**
 Tax year end Year Month Day: **2006-12-31**

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)? 1 Yes 2 No

1 Class number	2 Description	3 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	4 Cost of acquisitions during the year (new property must be available for use)*	5 Net adjustments**	6 Proceeds of dispositions during the year (amount not to exceed the capital cost)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)**	8 Reduced undepreciated capital cost	9 CCA rate %	10 Recapture of capital cost allowance (line 107 of Schedule 1)	11 Terminal loss (line 404 of Schedule 1)	12 Capital cost allowance (column 7 multiplied by column 8; or a lower amount) (line 403 of Schedule 1)***	13 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11)
200	201	202	203	204	205	206	207	208	209	210	211	212
1	Buildings	1,384,577	0	0	0	1,384,577	4	0	0	0	55,383	1,329,194
2	Equipment	30,623	29,059	0	0	45,152	20	0	0	0	9,030	50,652
3	Vehicles	632,646	236,948	24,441	24,441	738,899	30	0	0	0	221,670	623,483
4		51,092		0	0	51,092	30	0	0	0	15,328	35,764
5		40,162,012		0	0	40,162,012	4	0	0	0	1,606,480	38,555,532
6	Distribution after Feb 2005	8,816,451	5,711,218		0	11,672,060	8	0	0	0	933,765	13,593,904
	Total	51,077,401	5,977,225		24,441	54,053,792					2,841,656	54,188,529

* 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.
 **** 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.

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		5,977,225	
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	+		
Misc difference		3	
Total additions per books	=	5,977,228	5,977,228
Proceeds up to original cost - Schedule 8 regular classes		24,441	
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	+	71,390	
Additions included in regulatory assets		95,831	95,831
Total proceeds per books	=	95,831	95,831
Depreciation and amortization per accounts - Schedule 1	-		2,771,699
Loss on disposal of fixed assets per accounts	+		24,441
Gain on disposal of fixed assets per accounts	=		3,134,139
Net change per tax return			

Financial statements			
Fixed assets (excluding land) per financial statements			53,607,956
Closing net book value	-		50,473,817
Opening net book value	=		3,134,139
Net change per financial statements			
If the amounts from the tax return and the financial statements differ, explain why below			

RELATED AND ASSOCIATED CORPORATIONS

of corporation BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year end Year Month Day 2006-12-31
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This schedule is to be completed by a corporation having one or more of the following:

- related corporation(s)
- associated corporations(s)

	100 Name	200 Country of residence (if other than Canada)	300 Business Number (Canadian corporation only) (see note 1)	400 Relationship code (see note 2)	500 Number of common shares owned	550 % of common shares owned	600 Number of preferred shares owned	650 % of preferred shares owned	700 Book value of capital stock
1.	BRANTFORD ENERGY CORPORATIO		87504 1329 RC0001	1	1,001	100.000			22,437,505
2.	BRANTFORD HYDRO INC.		87504 1121 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.

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(99)



CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

No. of corporation BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year end Year Month Day 2006-12-31
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- 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	965,413	A
Add:			
Cost of eligible capital property acquired during the taxation year	222		
Other adjustments	226		
Subtotal (line 222 plus line 226)			B
$\times 3 / 4 =$			
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		C
$\times 1 / 2 =$			
amount B minus amount C (if negative, enter "0")			D
Amount transferred on amalgamation or wind-up of subsidiary	224		E
Subtotal (add amounts A, D, and E)	230	965,413	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)			
$\times 3 / 4 =$			
	248		J
Cumulative eligible capital balance (amount F minus amount J)		965,413	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		965,413	
less amount from line 249			
Current year deduction		965,413	
$\times 7.00 \% =$			
	250	67,579	*
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)		67,579	L
Cumulative eligible capital - Closing balance (amount K minus amount L) (if negative, enter "0")	300	897,834	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 years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409		9	
Line 6 minus line 9 (if negative, enter "0")				O
Line N minus line O (if negative, enter "0")				P
		Line 5	x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")				R
		Amount R	x 2 / 3 =	S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)					
Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1 Employee Future Benefits	491,850			46,264	445,586
2 Allowance for Doubtful Account	330,000		80,000		410,000
3					
Reserves from Part 2 of Schedule 13					
Totals	821,850		80,000	46,264	855,586

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.

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code 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
2004	\$225,001 to \$250,000
2005	\$250,001 to \$300,000
2006	maximum \$300,000
2007	\$300,001 to \$400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed \$400,000.

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
2006

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	2 Business Number of associated corporations	3 Association code	4 Business limit for the year (before the allocation) \$	5 Percentage of the business limit %	6 Business limit allocated* \$
	100	200	300		350	400
1	BRANTFORD POWER INC.	86585 8773 RC0001	1	300,000		
2	BRANTFORD ENERGY CORPORATION	87504 1329 RC0001	1	300,000		
	BRANTFORD HYDRO INC.	87504 1121 RC0001	1	300,000	100.0000	300,000
	Total				100.0000	300,000 A

Business limit reduction under subsection 125(5.1)

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 $0.225\% \times (A - \$10,000,000)$ 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. In this case, 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 *Income Tax Act*.

Canada



PART 1.3 TAX ON LARGE CORPORATIONS

Name of corporation BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year-end Year Month Day 2006-12-31
--	---	---

- This schedule is for use by corporations (other than financial institutions and insurance corporations) that have Part 1.3 tax payable before deducting surtax credits (line 820 in Part 5). You should also use and file this schedule if you calculate a gross Part 1.3 tax for the purposes of unused surtax credit (line 821 in Part 6) and a current-year unused surtax credit (line 850 in Part 8).
 - Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
 - Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
 - Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part 1.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
 - No Part 1.3 tax is payable for a taxation year by a corporation that was:
 - 1) bankrupt [as defined by subsection 128(3)] at the end of the year;
 - 2) a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
 - 3) exempt from tax under section 149 throughout the year on all of its taxable income;
 - 4) neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
 - 5) a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
 - File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the taxation year.
 - This schedule may contain changes that had not yet become law at the time of printing.
- Complete the following areas to determine the amounts needed to calculate Part 1.3 tax. If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101	<u>912,802</u>	
Capital stock (or members' contributions if incorporated without share capital)	103	<u>22,437,505</u> ✓	
Retained earnings	104	<u>6,210,743</u> ✓	
Contributed surplus	105		
Other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	<u>33,772,512</u>	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness in respect of a lease) that has been outstanding for more than 365 days before the end of the year	111	<u>2,177,025</u>	
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112		
		Subtotal	<u>65,510,587</u> ▶ <u>65,510,587</u> A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121		
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
Any amount deducted under subsection 135(1) in computing income under Part I for the year, to the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123		
The amount of deferred unrealized foreign exchange losses at the end of the year	124		
		Subtotal	▶ <u>190</u> <u>65,510,587</u> B

Capital for the year (amount A minus amount B) (if negative, enter "0")

Note:

Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined under lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Amounts owing to the member or to other corporations that are members of the partnership are not to be included.
- Amounts are determined as at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	_____
A loan or advance to another corporation (other than a financial institution)	402	_____
d, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	_____
Long-term debt of a financial institution	404	_____
A dividend receivable on a share of the capital stock of another corporation	405	_____
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part 1.3 (other than by reason of paragraph 181.1(3)(d))	406	_____
An interest in a partnership (see note 1 below)	407	_____
Investment allowance for the year	490	_____

Notes:

- Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
 - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
 - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's taxation year; and
 - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
- Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part 1.3 [other than by reason of paragraph 181.1(3)(d)].
- Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)	65,510,587	C
Deduct: Investment allowance for the year (line 490)	500	D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	65,510,587	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)	65,510,587	x	Taxable income earned in Canada	610	7,005,402	=	Taxable capital employed in Canada	690	65,510,587
			Taxable income		7,005,402				

- Notes:**
- Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
 - Where a corporation's taxable income for a taxation year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of \$1,000.
 - In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada	701	_____
Deduct the following amounts:		
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711	_____
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada	712	_____
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713	_____
Total deductions (add lines 711, 712, and 713)	E	_____
...ble capital employed in Canada (line 701 minus amount E) (if negative, enter "0")	790	_____

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation of gross Part 1.3 tax

Taxable capital employed in Canada (line 690 or 790, whichever applies)		65,510,587
Deduct: Capital deduction claimed for the year (enter \$50,000,000 or, for related corporations, the amount allocated on Schedule 36)	801	48,123,245
Amounts of taxable capital employed in Canada over capital deduction	811	17,387,342
Line 811	17,387,342	F
$\times \frac{\text{Number of days in the taxation year in 2004}}{\text{Number of days in the taxation year}}$	365	0.00200000 =
Line 811	17,387,342	G
$\times \frac{\text{Number of days in the taxation year in 2005}}{\text{Number of days in the taxation year}}$	365	0.00175000 =
Note: The Part 1.3 tax rate is reduced to 0% for the days in the taxation year that are after 2005.		
Subtotal (add amounts F and G)	H	
Where the taxation year of a corporation is less than 51 weeks, calculate the amount of gross Part 1.3 tax as follows:		
Amount H	(365)	I
$\times \frac{\text{Number of days in the year}}{365}$		
Gross Part 1.3 tax (amount H or I, whichever applies)	820	

Part 6 – Calculation of gross Part 1.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies)		65,510,587
Deduct: Line 801 above	48,123,245	9,624,649
$\times 1/5 =$		
Excess (amount J minus amount K) (if negative, enter "0")	55,885,938	
Amount L	55,885,938	M
$\times 0.00225 =$		
Where the taxation year of a corporation is less than 51 weeks, calculate the amount of gross Part 1.3 tax for purposes of the unused surtax credit as follows:		
Amount M	125,743	N
$\times \frac{\text{Number of days in the year}}{365}$		
Gross Part 1.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies)	821	125,743

AGREEMENT AMONG RELATED CORPORATIONS – PART 1.3 TAX

- Members of a related group of corporations should use this schedule to allocate the capital deduction of \$50,000,000 among the members of the related group. Do not file this agreement if no members of the related group have to pay Part 1.3 tax.
- In cases where a related corporation has more than one taxation year ending in a calendar year, it has to file an agreement for each of those taxation years.
- A corporation that is related to any other corporation at any time in a taxation year of the corporation that ends in a calendar year may file such an agreement.
- In accordance with subsection 181.5(7) of the federal *Income Tax Act*, a Canadian-controlled private corporation is not considered to be related to another corporation for purposes of the capital deduction unless it is also associated with that corporation.

Agreement

Date filed (do not use this area) **010** Year Month Day

Is this an amended agreement? **020** 1 Yes 2 No

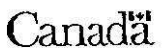
Calendar year to which the agreement applies **030** Year 2006

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part 1.3 tax under subsection 181.1(3) does not have to be included.

Names of all corporations which are members of the related group	Business Number (if a corporation is not registered, enter "NR")	Allocation of capital deduction for the year \$	Taxation year end to which this agreement applies* (YYYY/MM/DD)
200	300	400	500
BRANTFORD POWER INC.	86585 8773 RC0001	48,123,245	
1 BRANTFORD ENERGY CORPORATION	87504 1329 RC0001	3,717	
2 BRANTFORD HYDRO INC.	87504 1121 RC0001	1,873,038	

Total (cannot be more than \$50,000,000) **50,000,000**

* Entries are only required in this column for a corporation that has more than one taxation year ending in the same calendar year and is related in two or more of those taxation years to another corporation that has a taxation year ending in that calendar year. The capital deduction of the first corporation for each such taxation year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such taxation year. Enter the taxation year end to which this agreement applies.





SHAREHOLDER INFORMATION

of corporation BRANTFORD POWER INC.	Business Number 86585 8773 RC0001	Tax year end Year Month Day 2006-12-31
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All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder			Percentage common shares	Percentage preferred shares
		Business Number	Social insurance number	Trust number		
	100	200	300	350	400	500
1	BRANTFORD ENERGY CORPORATION	87504 1329 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						



ATTACHMENT J

REFERENCE: OEB STAFF QUESTION 7.1a) ii



Ministry of Finance
Corporations Tax
33 King Street West
PO Box 820
Oshawa ON L1H 8E9

2006

CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2003

Corporations Tax Act - Ministry of Finance (MOF)
Corporations Information Act - Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) CT23 Corporations Tax Return and the Ministry of Government Services (MGS) Annual Return. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the Exempt from Filing (EFF) declaration on page 2 or file the CT23 Return on pages 3-17. Corporations that do not meet the EFF criteria but do meet the Short-Form criteria, may request and file the CT23 Short-Form Return (see page 2).

The Annual Return (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the Corporations Information Act for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? (Not required if already filed or Annual Return exempt. Refer to Guide) Yes No **Page 1 of 20**

Ministry Use

Corporation's Legal Name (including punctuation)
BRANTFORD POWER INC.

Ontario Corporations Tax Account No. (MOF)
1800056

Mailing Address
**84 Market Square
P.O. Box 308
Brantford
ON CA N3T 5N8**

This Return covers the Taxation Year
Start **2006-01-01**
End **2006-12-31**

Has the mailing address changed since last filed CT23 Return? Yes No Date of Change year month day

Date of Incorporation or Amalgamation
 2000-03-01

Registered/Head Office Address
**84 Market Square
P.O. Box 308
Brantford
ON CA N3T 5N8**

Ontario Corporation No. (MGS)
1403713

Location of Books and Records
**84 Market Square
P.O. Box 308
Brantford
ON CA N3T 5N8**

Canada Revenue Agency Business No.
If applicable, enter
865858773-RC0001

Name of person to contact regarding this CT23 Return Telephone No. Fax No.
Brian D'Amboise (519) 759-4150

Jurisdiction Incorporated
Federal

Address of Principal Office in Ontario (Extra-Provincial Corporations only) (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced
Ceased

Former Corporation Name (Extra-Provincial Corporations only) Not Applicable (MGS)

Not Applicable

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s)

Preferred Language / Langue de préférence
 English / anglais French / français

If there is no change to the Directors/Officers/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). No Change



Certification (MGS)

I certify that all information set out in the Annual Return is true, correct and complete.
Name of Authorized Person (Print clearly or type in full)
Brian D'Amboise

Title: Director Officer Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the Corporations Information Act provide penalties for making false or misleading statements or omissions.

BRANTFORD POWER INC.

1800056

2006-12-31

CT23 Corporations Tax Return

Information continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

- 1**
- 1 Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
 - 2 Other Private
 - 3 Public
 - 4 Non-share Capital
 - 5 Other (specify) ▼

Share Capital with full voting rights owned by Canadian Residents 100 (nearest percent) %

- 2**
- 1 Family Farm corporation s.1(2)
 - 2 Family Fishing corporation s.1(2)
 - 3 Mortgage Investment corporation s.47
 - 4 Credit Union s.51
 - 5 Bank Mortgage subsidiary s.61(4)
 - 6 Bank s.1(2)
 - 7 Loan and Trust corporation s.61(4)
 - 8 Non-resident corporation s.2(2)(a) or (b)
 - 9 Non-resident corporation s.2(2)(c)
 - 10 Mutual Fund corporation s.48
 - 11 Non-resident owned investment corporation s.49
 - 12 Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
 - 14 Bare Trustee corporation
 - 15 Branch of Non-resident s.63(1)
 - 16 Financial institution prescribed by Regulation only
 - 17 Investment Dealer
 - 18 Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
 - 19 Hydro successor, municipal electrical utility or subsidiary of either
 - 20 Producer and seller of steam for uses other than for the generation of electricity
 - 21 Insurance Exchange s.74.4
 - 22 Farm Feeder Finance Co-operative corporation
 - 23 Professional corporation (incorporated professionals only)

- This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- Amended Return
- Taxation year end change -- Canada Revenue Agency approval required
- Final taxation year up to dissolution (Note: for discontinued businesses, see guide.)
- Final taxation year before amalgamation
- The corporation has a floating fiscal year end
- There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year
If checked, date control was acquired year month day
- The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)
- First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)
- Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

- | | | |
|-------------------------------------|-------------------------------------|--|
| Yes | No | |
| <input type="checkbox"/> | <input checked="" type="checkbox"/> | Was the corporation inactive throughout the taxation year? |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency? |
| Are you requesting a refund due to: | | |
| <input type="checkbox"/> | <input checked="" type="checkbox"/> | the Carry-back of a Loss? |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | an Overpayment? |
| <input type="checkbox"/> | <input checked="" type="checkbox"/> | a Specified Refundable Tax Credit? |
| <input checked="" type="checkbox"/> | <input type="checkbox"/> | Are you a member of a Partnership or Joint Venture? |

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	+	From 690	7,005,402	.
Subtract: Charitable donations	-	1		.
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property (Attach schedule 2)	-	2		.
Subtract: Taxable dividends deductible, per federal Schedule 3	-	3		.
Subtract: Ontario political contributions (Attach Schedule 2A) (Int.B. 3002R)	-	4		.
Subtract: Federal Part VI.1 tax	-	5		.
Subtract: Prior years' losses applied – Non-capital losses	-	From 704		.
Net capital losses (page 16) \times inclusion rate 50.000000% =	-	714		.
Farm losses	-	From 724		.
Restricted farm losses	-	From 734		.
Limited partnership losses	-	From 754		.
Taxable Income (Non-capital loss)	=	10	7,005,402	.
Addition to taxable income for unused foreign tax deduction for federal purposes	+	11		.
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	7,005,402	.

Taxable Income					
From 10 (or 20 if applicable) 7,005,402 \times 30 Ontario Allocation 100.0000 % \times 12.5% \times 33 73 365 = + 29					
From 10 (or 20 if applicable) 7,005,402 \times 30 Ontario Allocation 100.0000 % \times 14% \times 34 365 73 365 = + 32 980,756					
Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 980,756					

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

~~Section is not completed, the IDSBC will be denied.~~

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? Yes No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))		50	
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51	
Add: Losses of other years deducted for federal purposes (fed.s.111)	+	52	
Subtract: Losses of other years deducted for Ontario purposes (s.34)	-	53	
	=	54	
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	

Ontario Business Limit Calculation

320,000 \times 31 365 = + 46			
400,000 \times 34 365 = + 47 400,000			
Business Limit for Ontario purposes 46 + 47 = 44 400,000 \times 48 % = 45			
Income eligible for the IDSBC From 30 100.0000 % \times 56 = 60			
		***Ontario Allocation	Least of 50, 54 or 45

Note: Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)
 Note: Adjust accordingly for a floating taxation year and use 366 for a leap year.
 *** Note: Ontario Allocation for IDSBC purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).

Income Tax continued from Page 4

Calculation of IDSBC Rate

		7% x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2002 and before Jan. 1, 2004</td> <td>Total Days</td> </tr> <tr> <td>31</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days	31	365	= +	89	
Number of Days in Taxation Year												
Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days											
31	365											
		8.5% x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2003</td> <td>Total Days</td> </tr> <tr> <td>34</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2003	Total Days	34	365	= +	90	8,5000
Number of Days in Taxation Year												
Days after Dec. 31, 2003	Total Days											
34	365											
				=	78	8,5000						
IDSBC Rate for Taxation Year					89 + 90							
Claim	From 60	x	From 78	8,5000%		= 70						

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*Taxable Income of the corporation From 10 (or 20 if applicable) + 80 7,005,402

If you are a member of an associated group (X) 81 (X) (Yes)

Name of associated corporation (Canadian & foreign) (if insufficient space, attach schedule)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	* Taxable Income (if loss, enter nil)
BRANTFORD ENERGY CORPORATION	1800054	2006-12-31	+ 82
BRANTFORD HYDRO INC.	1800055	2006-12-31	+ 83
			+ 84
			= 85 7,005,402

Aggregate Taxable Income 80 + 82 + 83 + 84, etc. = 86 6,605,402

Calculation of Specified Rate for Surtax

320,000 x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2002 and before Jan. 1, 2004</td> <td>Total Days</td> </tr> <tr> <td>31</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days	31	365	= +	115	
Number of Days in Taxation Year										
Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days									
31	365									
400,000 x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2003</td> <td>Total Days</td> </tr> <tr> <td>34</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2003	Total Days	34	365	= +	116	400,000
Number of Days in Taxation Year										
Days after Dec. 31, 2003	Total Days									
34	365									
			115 + 116	= 400,000						
				= 114 400,000						
				= 86 6,605,402						

(If negative, enter nil)

Calculation of Specified Rate for Surtax

		4.6670% x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2002</td> <td>Total Days</td> </tr> <tr> <td>38</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2002	Total Days	38	365	= +	97	4.6670
Number of Days in Taxation Year												
Days after Dec. 31, 2002	Total Days											
38	365											
	From 86	6,605,402	x	From 97	4.6670%	= 87 308,274						
	From 87	308,274	x	From 60		÷ From 114 400,000 = 88						
Surtax Lesser of	70	or	88			= 100						

Short Taxation Years - Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

Additional Deduction for Credit Unions (s.51(4)) (Attach schedule 17) 110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: a) your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and b) the total active business income is \$250,000 or less.

Eligible Canadian Profits 120
 Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) From 56

Add: Adjustment for Surtax on Canadian-controlled private corporations
 $\frac{\text{From } 100}{100} + \frac{\text{From } 30}{30} \times 100.0000\% \div \frac{\text{From } 78}{78} \times 8.5000\% = 121$
 *Ontario Allocation

Lesser of 56 or 121 122
 120 - 56 + 122 130

Taxable Income From 10 7,005,402

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) From 56

Add: Adjustments for Surtax on Canadian-controlled private corporations From 122

Subtract: Taxable Income 10 7,005,402 X Allocation % to jurisdictions outside Canada % 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses 141

1 56 + 122 - 140 - 141 142 7,005,402

Claim

143 \times From 30 100.0000% \times 1.5% \times

Number of Days in Taxation Year	
Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days
33	365

 \div 73 365 = + 154

143 \times From 30 100.0000% \times 2% \times

Number of Days in Taxation Year	
Days after Dec. 31, 2003	Total Days
34	365

 \div 73 365 = + 156

M&P claim for taxation year 154 + 156 160

* Note: Ontario Allocation for M&P Credit purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))

Manufacturing and Processing Profits Credit for Electrical Generating Corporations 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity 162

Credit for Foreign Taxes Paid (s.40) 170
 Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). (Attach schedule).

Credit for Investment in Small Business Development Corporations (SBDC)
 Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former Small Business Development Corporations Act)
 Eligible Credit 175 Credit Claimed 180

Subtotal of Income Tax 40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180 190 980,756

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Income Tax continued from Page 6

Specified Tax Credits (Refer to Guide)

Ontario Innovation Tax Credit (OITC) (s.43.3) Applies to scientific research and experimental development in Ontario. Eligible Credit From 5620 OITC Claim Form (Attach original Claim Form)

+ 191

Co-operative Education Tax Credit (CETC) (s.43.4) Applies to employment of eligible students. Eligible Credit From 5798 CT23 Schedule 113 (Attach Schedule 113)

+ 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5) Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. 204 Name of Production

Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility)

+ 193

Graduate Transitions Tax Credit (GTTC) (s.43.6) Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194 No. of Graduates From 6596

Eligible Credit From 6598 CT23 Schedule 115 (Attach Schedule 115)

+ 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7) Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form (Attach both the original Claim Form and the Certificate of Eligibility)

+ 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8) Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility)

+ 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9) Applies to qualifying R&D expenditures under an eligible research institute contract.

Eligible Credit From 7100 OBRITC Claim Form (Attach original Claim Form)

+ 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10) Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.

Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility)

+ 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11) Applies to qualifying labour expenditures of eligible products for the taxation year.

Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility)

+ 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12) Applies to qualifying expenditures in respect of eligible Canadian sound recordings.

Eligible Credit From 7500 OSRTC Claim Form (Attach both the original Claim Form and the Certificate of Eligibility)

+ 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13) Applies to employment of eligible apprentices. 202 No. of Apprentices From 5896

Eligible Credit From 5898 CT23 Schedule 114 (Attach Schedule 114)

+ 203

Other (specify)

+ 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits Applied to reduce Income Tax = 225

Income Tax 190 - 225 OR Enter NIL if reporting Non-Capital Loss (amount cannot be negative) = 230 980,756

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see Determination of Applicability section for the CMT on Page 8. If CMT is not applicable, transfer amount in 230 to Income Tax in Summary section on Page 17.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the Application of CMT Credit Carryovers section part B, on Page 8.

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation + [240] 81,065,466 .
 Total Revenue of the corporation + [241] 87,905,944 .

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) [242] (Yes)

Name of associated corporation (Canadian & foreign) (if insufficient space attach schedule)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
BRANTFORD ENERGY CORPORATION	1800054	2006-12-31	+ [243] 23,922,884 .	+ [244] 176,106 .
BRANTFORD HYDRO INC.	1800055	2006-12-31	+ [245] 2,551,528 .	+ [246] 1,453,516 .
			+ [247] .	+ [248] .
Aggregate Total Assets	[240] + [243] + [245] + [247], etc.		= [249] 107,539,878 .	
Aggregate Total Revenue	[241] + [244] + [246] + [248], etc.			= [250] 89,535,566 .

Determination of Applicability

Applies if either Total Assets [249] exceeds \$5,000,000 or Total Revenue [250] exceeds \$10,000,000.

Short Taxation Years - Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation - The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section Calculation: CMT below and Corporate Minimum Tax Schedule 101.

Calculation: CMT (Attach Schedule 101.)

Gross CMT Payable CMT Base From Schedule 101 [2136] 4,445,802 . X From [30] 100.0000 % X [4] % = [276] 177,832 .
If negative, enter zero Ontario Allocation

Subtract: Foreign Tax Credit for CMT purposes (Attach Schedule) [277] .
 Subtract: Income Tax From [180] 980,756 .

Net CMT Payable (If negative, enter Nil on Page 17.) = [280] 802,924 .

If [280] is less than zero and you do not have a CMT credit carryover, transfer [230] from Page 7 to Income Tax Summary, on Page 17.

If [280] is less than zero and you have a CMT credit carryover, complete A & B below.

If [280] is greater than or equal to zero, transfer [230] to Page 17 and transfer [280] to Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.

CMT Credit Carryover available From Schedule 101 From [2333] .

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) + From [190] 980,756 .
 Gross CMT Payable + From [276] 177,832 .
 Subtract: Foreign Tax Credit for CMT purposes - From [277] .
 If [276] - [277] is negative, enter NIL in [290] = 177,832 .
 Income Tax eligible for CMT Credit = [300] 802,924 .

B. Income Tax (after deduction of specified credits) + From [230] 980,756 .
 Subtract: CMT credit used to reduce income taxes - [310] .
 Income Tax = [320] 980,756 .
Transfer to page 17

If A & B apply, [310] cannot exceed the lesser of [230], [300] and your CMT credit carryover available [2333] .

If only B applies, [310] cannot exceed the lesser of [230] and your CMT credit carryover available [2333] .

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Capital Tax (Refer to Guide and Int.B. 3011R)

If corporation is a Financial Institution (s.58(2)), complete lines 480 and 481 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both \$3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be

adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose business is not carried on solely in Canada is deemed to be the greater of (1) taxable income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Table with columns for description, line number, and amount. Rows include Paid-up capital stock, Retained earnings, Loans and advances, Bank loans, Bankers acceptances, Bonds and debentures payable, Mortgages payable, Lien notes payable, Deferred credits, Other reserves, Share of partnership(s) paid-up capital, Subtotal, Subtract: Amounts deducted for income tax purposes, Deductible R & D expenditures, Total Paid-up Capital, Subtract: Deferred mining exploration and development expenses, Net Paid-up Capital.

Eligible Investments (Refer to Guide and Int.B. 3015R)

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Table with columns for description, line number, and amount. Rows include Bonds, lien notes and similar obligations, Mortgages due from other corporations, Shares in other corporations, Loans and advances to unrelated corporations, Loans and advances to related corporations, Share of partnership(s) or joint venture(s) eligible investments, Total Eligible Investments.

continued on Page 10

DOLLARS ONLY

Total Assets (Int.B. 3015R)		+ 420	81,065,466
Total Assets per balance sheet		+ 421	
Mortgages or other liabilities deducted from assets		+ 422	
\$ of partnership(s)/joint venture(s) total assets (Attach schedule)		- 423	
Subtract: Investment in partnership(s)/joint venture(s)		= 430	81,065,466
Total Assets as adjusted		+ 440	
Amounts in 360 and 361 (if deducted from assets)		- 441	2,010,031
Subtract: Amounts in 371, 372 and 381		- 442	
Subtract: Appraisal surplus if booked		+ 443	
Add or Subtract: Other adjustments (specify on an attached schedule)		= 450	79,055,435
Total Assets			

Investment Allowance $(\frac{410}{450}) \times 390$	Not to exceed 410	= 460	
Taxable Capital 390 - 460		= 470	65,068,876

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	87,905,944
Total Assets (as adjusted)	From 430	81,065,466

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: This version (2006) of the CT23 may only be used for a taxation year that commenced after December 31, 2003. Financial Institutions use calculations on page 13.

- Important:** If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.
- OR If the corporation is not a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C below, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.
 - OR If the corporation is a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018). Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

Calculation of Taxable Capital Deduction (TCD)

		Number of Days in Taxation Year			
		Days before Jan. 1, 2005	Total Days		
5,000,000	x	35	365	= +	500
7,500,000	x	36	365	= +	501
10,000,000	x	37	365	= +	502
Taxable Capital Deduction (TCD)				=	503

SECTION C

This section applies if the corporation is not a member of an associated group and/or partnership.

- C1.** If 430 and 480 on page 10 are both \$3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.
- C2.** If Taxable Capital in 470 is equal to or less than the TCD in 503, enter NIL in 550 on page 12 and complete the return from that point.
- C3.** If Taxable Capital in 470 exceeds the TCD in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

$$\begin{aligned}
 & \text{r From } 470 \\
 & - \text{From } 503 \\
 & = 471 \times \text{From } 30 \text{ Ontario Allocation } 100.0000\% \times 0.3\% \times \frac{\text{Days in taxation year } 555}{365 \text{ (366 if leap year)}}{365} = + 523
 \end{aligned}$$

Transfer to 543 on page 12 and complete the return from that point

continued on Page 11

If floating taxation year, refer to Guide.

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Capital Tax Calculation *continued from Page 10*

SE **END**

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. 509 (X if applicable)

All corporations that you are associated with do not have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to Section E, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. 524 (X if applicable)

One or more of the corporations that you are associated with maintains a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group may file an election under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

Calculation Do not complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10

+ From 470 65,068,876

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada (If insufficient space, attach schedule)

Ontario Corporations Tax Account No. (MOF) (if applicable)

Taxation Year End

Taxable Capital

BRANTFORD ENERGY CORPORATION
BRANTFORD HYDRO INC.

1800054
1800055

2006-12-31
2006-12-31

+ 531 31,053
+ 532 1,994,775
+ 533
= 540 67,094,704

Aggregate Taxable Capital 470 + 531 + 532 + 533, etc.

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E on page 12, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E on page 12.

From 470 65,068,876 ÷ From 540 67,094,704 × From 503 10,000,000 = 541 9,698,064

Transfer to 542 in Section E on page 12

s.69(2.1) Election Filed

591 (X if applicable)

Election filed. Attach a copy of Schedule 591 with this CT23 Return. Proceed to Section F on page 12.

continued on Page 12

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Capital Tax continued from Page 12

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing after May 4, 1999 enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 585 and 570. Do not submit with this tax return.)

565 x 0.6% x From 30 100.0000% x 555 365 / 365 (366 if leap year) = + 569
Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1

570 x 571 x From 30 100.0000% x 555 365 / 365 (366 if leap year) = + 574
Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount
Capital Tax Rate (Refer to Guide)
Ontario Allocation

Capital Tax for Financial Institutions - other than Credit Unions (before Section 2) 569 + 574 = 575

* If final taxation year, refer to Guide.

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments - 585
Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) Yes

Capital Tax - Financial Institutions 575 - 585 = 586
Transfer to 543 on Page 12

Premium Tax (s.74.2 & 74.3) (Refer to Guide)

(1) Uninsured Benefits Arrangements - 587 x 2% = 588
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax (Refer to Guide) - 589
Premium Tax 588 - 589 = 590
Transfer to page 17

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 + [600] 7,005,402.
Transfer to Page 15

Add:

Federal capital cost allowance	+ [601]	2,841,656	.
Federal cumulative eligible capital deduction	+ [602]	67,579	.
Ontario taxable capital gain	+ [603]		.
Federal non-allowable reserves. Balance beginning of year	+ [604]	821,850	.
Federal allowable reserves. Balance end of year	+ [605]		.
Ontario non-allowable reserves. Balance end of year	+ [606]	855,586	.
Ontario allowable reserves. Balance beginning of year	+ [607]		.
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ [608]		.
Federal resource allowance (Refer to Guide)	+ [609]		.
Federal depletion allowance	+ [610]		.
Federal foreign exploration and development expenses	+ [611]		.
All Crown charges, royalties, rentals, etc. deducted for Federal purposes (Refer to Guide)	+ [617]		.
Management fees, rents, royalties and similar payments to non-arm's length non-residents			.

Number of Days in Taxation Year

[612] x 5 / 12.5 x [33] ÷ 73 = 365 =+ [633]

[612] x 5 / 14 x [34] ÷ 73 = 365 =+ [634]

add-back amount for Management fees, etc. [633] + [634] = [613]

Federal Scientific Research Expenses claimed in year from line [460] of fed. form T661 excluding any negative amount in [473] from Ont. CT23 Schedule 161	+ [615]	
Add any negative amount in [473] from Ont. CT23 Schedule 161	+ [616]	
Federal allowable business investment loss	+ [620]	
Total of other items not allowed by Ontario but allowed federally (Attach schedule)	+ [614]	
Total of Additions [601] to [611] + [617] + [613] + [615] + [616] + [620] + [614]	=	4,586,671 [640] 4,586,671. Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under [675])	+ [650]	2,841,656	.
Ontario cumulative eligible capital deduction	+ [651]	67,579	.
Federal taxable capital gain	+ [652]		.
Ontario non-allowable reserves. Balance beginning of year	+ [653]	821,850	.
Ontario allowable reserves. Balance end of year	+ [654]		.
Federal non-allowable reserves. Balance end of year	+ [655]	855,586	.
Federal allowable reserves. Balance beginning of year	+ [656]		.
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) (Retain calculations. Do not submit.)	+ [657]		.
Ontario depletion allowance	+ [658]		.
Ontario resource allowance (Refer to Guide)	+ [659]		.
Ontario current cost adjustment (Attach schedule)	+ [661]		.
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ [675]		.

Total of deductions for this page [650] to [659] + [661] + [675] [681] 4,586,671.
Transfer to Page 15

BRANTFORD POWER INC.

1800056

2006-12-31

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1

From + [600] 7,005,402

Total of Additions on page 14

From = [640] 4,586,671

Sub Total of deductions on page 14

From = [681] 4,586,671

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up (Applies only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year

[662]

ONTTI Gross-up deduction-calculation:

Gross-up of CCA

From [662] x [100] - From [662] = [663]
From [30] 100.0000
Ontario Allocation

Workplace Child Care Tax Incentive (WCCT)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665] x 30% x [100] = [666]
From [30] 100.0000
Ontario allocation

Workplace Accessibility Tax Incentive (WATI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667] x 100% x [100] = [668]
From [30] 100.0000
Ontario allocation

Number of Employees accommodated

[669]

Ontario School Bus Safety Tax Incentive (OSBSTI)

(Applies to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) (Refer to Guide)

Qualifying expenditures: [670] x 30% x [100] = [671]
From [30] 100.0000
Ontario allocation

Educational Technology Tax Incentive (ETTI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672] x 15% x [100] = [673]
From [30] 100.0000
Ontario allocation

Ontario allowable business investment loss

+ [678]

Ontario Scientific Research Expenses claimed in year in [477] from Ont. CT23 Schedule 161

+ [679]

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)

+ [677]

Total of other deductions allowed by Ontario (Attach schedule)

+ [664]

Total of Deductions [681] + [663] + [666] + [668] + [671] + [673] + [678] + [679] + [677] + [664] = 4,586,671 [680] 4,586,671

Net income (loss) for Ontario Purposes [600] + [640] - [680] = [690] 7,005,402
Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2)	720 (2)	730	740	750
Add:						
Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract:						
Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year 1998-06-30	817 (9)	860 (9)		850	870
8 8th preceding taxation year 1999-06-30	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2000-02-29	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2000-12-31	820	830	840	853	873
804 5th preceding taxation year 2001-12-31	821	831	841	854	874
805 4th preceding taxation year 2002-12-31	822	832	842	855	875
806 3rd preceding taxation year 2003-12-31	823	833	843	856	876
807 2nd preceding taxation year 2004-12-31	824	834	844	857	877
808 1st preceding taxation year 2005-12-31	825	835	845	858	878
809 Current taxation year 2006-12-31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

- (1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.
- (2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 1(5.5), as made applicable by s.34.
- (3) includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.
- (4) To the extent of applicable gains/income/at-risk amount only.

- (5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.
- (6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.
- (7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.
- (8) Amount in 709 must equal total of 829 + 839.
- (9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

BRANTFORD POWER INC.

1800056

2006-12-31

DOLLARS ONLY

Request for Loss Carry-Back (s.80(16))

Applicants to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under any Act administered by the Ministry of Finance.

- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
1) the first day of the taxation year after the loss year,
2) the day on which the corporation's return for the loss year is delivered to the Minister, or
3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
If a loss is being carried back to a predecessor corporation, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

Table with columns for Total amount of loss, Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income, and Total loss to be carried back. Includes rows for 3rd, 2nd, and 1st preceding years.

Table with columns for Non-Capital Losses, Total Capital Losses, Farm Losses, and Restricted Farm Losses. Includes rows for years 910-949.

Summary

Summary table showing Income Tax, Corporate Minimum Tax, Capital Tax, Premium Tax, Total Tax Payable, Subtractions (Capital Gains Refund, etc.), Balance, and payment details.

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation.

Form for certification including Name (Brian D'Amboise), Title (CFO), Full Residence Address, Signature, and Date (2007-04-14).

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the Minister of Finance and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. (Refer to Guide for other payment methods.)

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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P : Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP) ± **2100** **1,916,630**

Subtract (to the extent reflected in net income/loss):

Provision for recovery of income taxes / benefit of current income taxes	+ 2101	
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102	
Equity income from corporations	+ 2103	
Share of partnership(s)/joint venture(s) income	+ 2104	
Dividends received/receivable deductible under fed.s.112	+ 2105	
Dividends received/receivable deductible under fed.s.113	+ 2106	
Dividends received/receivable deductible under fed.s.83(2)	+ 2107	
Dividends received/receivable deductible under fed.s.138(6)	+ 2108	
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1)		× 3
	+ 2109	
Subtotal	=	2110

Add (to extent reflected in net income/loss):

Provision for current taxes / cost of current income taxes	+ 2111	2,529,172
Provision for deferred income taxes (debits) / cost of future income taxes	+ 2112	
Equity losses from corporations	+ 2113	
Share of partnership(s)/joint venture(s) losses	+ 2114	
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+ 2115	
Subtotal	=	2116 2,529,172

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85	+ 2117		or - 2118	
** Fed.s.85.1	+ 2119		or - 2120	
** Fed.s.97	+ 2121		or - 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or - 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125		or - 2126	
** Amounts relating to s.57.10 election/regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years	+ 2127		or - 2128	

Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income

Subtotal (Additions)	=		+ 2129	
Subtotal (Subtractions)	=		- 2130	
** Other adjustments			± 2131	
Subtotal	± 2100 - 2110 + 2116 + 2129 - 2130 ± 2131		= 2132	4,445,802
** Share of partnership(s)/joint venture(s) adjusted net income/loss			+ 2133	
Adjusted net income (loss) (if loss, transfer to 2202 in Part 2: Continuity of CMT Losses Carried Forward.)			= 2134	4,445,802

Deduct: * CMT losses: pre-1994 Loss	+ From 2210	
* CMT losses: other eligible losses	+ 2211	
	=	2135

* CMT losses applied cannot exceed adjusted net income or increase a loss

** Retain calculations. Do not submit with this schedule.

CMT Base	=	2136	4,445,802
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Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CTB

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)		+ [2201]	[]
Add: Current year's losses	+ [2202]	[]	
Losses from predecessor corporations on amalgamation NOTE (3)	+ [2203]	[]	
Losses from predecessor corporations on wind-up NOTE (3)	+ [2204]	[]	
Amalgamation (X) [2205] <input type="checkbox"/> Yes Wind-up (X) [2206] <input type="checkbox"/> Yes	=	[]	
Subtotal		+ [2207]	[]
Adjustments (attach schedule)		± [2208]	[]
CMT losses available [2201] + [2207] ± [2208]		= [2209]	[]
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income	+ [2210]	[]	
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ [2211]	[]	
Losses expired during the year	+ [2212]	[]	
Subtotal	=	[]	
Balances at End of Year NOTE (5) [2209] - [2213]		= [2214]	[]

Notes:

- (1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.
- (2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and s.57.5(7))
- (3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))
- (4) CMT losses must be used to the extent of the lesser of the adjusted net income [2134] and CMT losses available [2209].
- (5) Amount in [2214] must equal sum of [2270] + [2290].

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
[2240]	9th preceding taxation year 1998-06-30	[2260]	[2280]
[2241]	8th preceding taxation year 1999-06-30	[2261]	[2281]
[2242]	7th preceding taxation year 2000-02-29	[2262]	[2282]
[2243]	6th preceding taxation year 2000-12-31	[2263]	[2283]
[2244]	5th preceding taxation year 2001-12-31	[2264]	[2284]
[2245]	4th preceding taxation year 2002-12-31	[2265]	[2285]
[2246]	3rd preceding taxation year 2003-12-31	[2266]	[2286]
[2247]	2nd preceding taxation year 2004-12-31	[2267]	[2287]
[]	1st preceding taxation year 2005-12-31	[2268]	[2288]
[2249]	Current taxation year 2006-12-31	[2269]	[2289]
Totals		[2270]	[2290]

The sum of amounts [2270] + [2290] must equal amount in [2214].

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1)		+ 2301	
Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL)	+ From 280 or 347		
Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.)	+ From 312		
Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8)	- From 190	- 2305	
Subtotal (If negative, enter NIL)	=	+ 2310	
Current year's CMT credit (If negative, enter NIL) 280 or 347 - 2305	=	+ 2325	
CMT Credit Carryovers from predecessor corporations NOTE (3)			
Amalgamation (X) 2315 <input type="checkbox"/> Yes Wind-up (X) 2320 <input type="checkbox"/> Yes		= 2330	
Subtotal 2301 + 2310 + 2325		+ 2332	
Adjustments (Attach schedule)		= 2333	
CMT Credit Carryover available 2330 ± 2332			<i>Transfer to Page 8 of the CT23 or Page 6 of the CTB</i>
Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.)	+ From 310 or 351		
CMT Credit expired during the year	+ 2334	- 2335	
Subtotal	=	= 2336	
Balances at End of Year NOTE (4) 2333 - 2335			

Notes:

- (1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))
- (2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).
- (3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))
- (4) Amount in **2336** must equal sum of **2370** + **2390**.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 1998-06-30	2360	2380
2341	8th preceding taxation year 1999-06-30	2361	2381
2342	7th preceding taxation year 2000-02-29	2362	2382
2343	6th preceding taxation year 2000-12-31	2363	2383
2344	5th preceding taxation year 2001-12-31	2364	2384
2345	4th preceding taxation year 2002-12-31	2365	2385
2346	3rd preceding taxation year 2003-12-31	2366	2386
2347	2nd preceding taxation year 2004-12-31	2367	2387
2348	1st preceding taxation year 2005-12-31	2368	2388
2349	Current taxation year 2006-12-31	2369	2389
Totals		2370	2390

The sum of amounts **2370** + **2390**
must equal amount in **2336**.

Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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CN Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

**(ii) Continuity of Other Eligible CMT Losses – Filing Corporation
(for losses occurring in tax years commencing after 1993)**

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-06-30					
9th Prior Year	1998-06-30					
8th Prior Year	1999-06-30					
7th Prior Year	2000-02-29					
6th Prior Year	2000-12-31					
5th Prior Year	2001-12-31					
4th Prior Year	2002-12-31					
3rd Prior Year	2003-12-31					
2nd Prior Year	2004-12-31					
1st Prior Year	2005-12-31					
Total						

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-06-30						
1998-06-30						
1999-06-30						
2000-02-29						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

**Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule**

Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-06-30						
1998-06-30						
1999-06-30						
2000-02-29						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

**Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule**

Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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CI Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-06-30					
9th Prior Year	1998-06-30					
8th Prior Year	1999-06-30					
7th Prior Year	2000-02-29					
6th Prior Year	2000-12-31					
5th Prior Year	2001-12-31					
4th Prior Year	2002-12-31					
3rd Prior Year	2003-12-31					
2nd Prior Year	2004-12-31					
1st Prior Year	2005-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-06-30						
1998-06-30						
1999-06-30						
2000-02-29						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-06-30						
1998-06-30						
1999-06-30						
2000-02-29						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						



Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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Loans or Advances Credited or Advanced to Corporation
 (includes accounts payable to related parties outstanding at the taxation year end for 120 days or more,
 and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Note payable to City of Brantford	+	24,189,168
Customer deposits	+	2,383,789
Interest payable to City of Brantford	+	3,745,345
Royal Bank loans	+	7,100,000
Due to Brantford Energy Corporation	+	99,555
Accumulated sick leave credits	+	57,216
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total	=	37,575,073

Transfer to 353 of the CT23



Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Capital Co Allowance Schedule 8

Corporation's Legal Name: **BRANTFORD POWER INC.** Ontario Corporations Tax Account No. (MOF): **1800056** Taxation Year End: **2006-12-31**

Is the corporation electing under regulation 1101(5q)? 1 Yes 2 No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	1,384,577			0	1,384,577		1,384,577	4	0	0	55,383	1,329,194
8	30,623	29,059		0	59,682	14,530	45,152	20	0	0	9,030	50,652
10	632,646	236,948		24,441	845,153	106,254	738,899	30	0	0	221,670	623,483
10	51,092			0	51,092		51,092	30	0	0	15,328	35,764
1	40,162,012			0	40,162,012		40,162,012	4	0	0	1,606,480	38,555,532
47	8,816,451	5,711,218		0	14,527,669	2,855,609	11,672,060	8	0	0	933,765	13,593,904
Totals	51,077,401	5,977,225		24,441	57,030,185	2,976,393	54,053,792				2,841,656	54,188,529

Enter in boxes **650** **650** **650** on the CT23.

Note 1. 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) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.



Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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- For use by a corporation that has eligible capital property.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year (if negative, enter zero) **965,413 A**

Add: Cost of eligible capital property acquired during the taxation year .. + **B**

Amount transferred on amalgamation or wind-up of subsidiary + **C**

Other adjustments + **D**

Total of B + C + D = **E** x 3 / 4 = **E**

Subtotal A + E = **965,413 F**

Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year + **G**

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the Income Tax Act (Canada) + **H**

Other adjustments + **I**

Total of G + H + I = **J** x 3 / 4 = **J**

Ontario cumulative eligible capital balance F - J = **965,413 K**

If K is negative, enter zero at line M and proceed to Part 2

Current year deduction **965,413 K** x 7% * = **67,579 L**

* The maximum current year deduction is 7%. However, you can claim any amount up to the maximum. Enter amount in box 851 of the CT23

Ontario cumulative eligible capital – closing balance K - L (if negative, enter zero) = **897,834 M**

Note: Any amount up to the maximum deduction of 7% may be claimed. Taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.

Part 2 – Amount to be included in income arising from disposition

Only complete this part only if the amount at line K is negative

Amount from line K above show as a positive amount **N**

Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988 **1**

Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA **2**

Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988 **3**

Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988 **4**

Line 3 deduct line 4 **5**

Total lines 1 + 2 + 5 **6**

Line T from previous Ontario Schedule 10 for taxation years ending after February 27, 2000 **7**

Deduct line 7 from line 6 **O**

N - O (cannot be negative) **P**

Amount on line 5 **1** x 1 / 2 **Q**

P - Q **R**

Amount on line R **1** x 2 / 3 **S**

Lesser of line N or line O **T**

Amount to be included in income S + T **T**

Note: For taxation years ending after February 27, 2000 and before October 18, 2000 use 8/9 to calculate S

Corporation's Legal Name BRANTFORD POWER INC.	Ontario Corporations Tax Account No. (MOF) 1800056	Taxation Year End 2006-12-31
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For use by a corporation to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 - Capital gains reserves

Description of property	Ontario balance at the beginning of the year \$	Transfer on amalgamation or wind-up of subsidiary \$	Add	Deduct	Ontario balance at the end of the year \$
1					
Totals	A	B			C

The total capital gains reserve at the beginning of the taxation year A plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary B, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year C, should also be entered on Schedule 6.

Part 2 - Other reserves

Description	Ontario balance at the beginning of the year \$	Transfer on amalgamation or wind-up of subsidiary \$	Add	Deduct	Ontario balance at the end of the year \$
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

The amount from D plus the amount from E should be entered in **607** of the CT23.

The amount from F should be entered in **654** of the CT23.

Part 3 - Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Employee Future Benefits	491,850			46,264		445,586
Allowance for Doubtful Accounts	330,000		80,000			410,000
Reserves from Part 2						
Totals	821,850		80,000	46,264		855,586

Enter in box **653** of the CT23

Enter in box **606** of the CT23

ATTACHMENT K

REFERENCE: OEB STAFF QUESTION 7.1a) iv



Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Account No.
1800056

35
PX5003

BRANTFORD POWER INC.
C/O BRIAN D'AMBOISE
84 MARKET SQUARE
P.O. BOX 308
BRANTFORD
N3T 5N8

ON

Remittance Advice - Payment-in-Lieu (PIL)
Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Taxation Year End: (YYYYMMDD)

Payment Amount: \$

Taxation Year End: (YYYYMMDD)

Payment Amount: \$

Total Payment Enclosed: \$



Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2006/01/01 to 2006/12/31

BRANTFORD POWER INC.
ASSESSMENT NO. 114

Account No.	Assessment Date (year, month, day)	Page
1800056	2007/06/13	1 of 1

Tax: Federal and Provincial PIL
Assessment Interest
Total Assessment Liability

2,696,464.00
16,048.76
2,712,512.76

SUMMARY OF 2006/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	2,696,464.00CR	
Sub-Total		<u>2,696,464.00CR</u>
TAXATION YEAR BALANCE DUE **		<u>16,048.76</u>

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

**Remember to include additional interest due with your payment. Interest on the balance is compounded daily from the date of this Notice/Statement until payment is received by the Ontario Electricity Financial Corporation (OEFC). The current interest rate is 0.0246575%.

ATTACHMENT L

REFERENCE: OEB STAFF QUESTION 7.3

FinStmt		BS	OK?	YES
Sum of Amount				
GroupDesc	AcctDesc			Total
1050-Current Assets	1005-Cash			4,984,859
	1040-Other Special Deposits			421,824
	1100-Customer Accounts Receivable			7,150,829
	1102-Accounts Receivable - Services			1,000
	1104-Accounts Receivable - Recoverable Work			440,000
	1110-Other Accounts Receivable			104,000
	1120-Accrued Utility Revenues			8,662,529
	1130-Accumulated Provision for Uncollectible Accounts--Credit			-410,000
	1150-Rents Receivable			13,000
	1180-Prepayments			320,978
	1190-Miscellaneous Current and Accrued Assets			0
1050-Current Assets Total				21,689,019
1100-Inventory	1330-Plant Materials and Operating Supplies			2,324,107
1100-Inventory Total				2,324,107
1150-Non-Current Assets	1410-Other Special or Collateral Funds			2,057,317
1150-Non-Current Assets Total				2,057,317
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets			88,509
	1518-RCVARetail			18,041
	1520-Power Purchase Variance Account			0
	1525-Miscellaneous Deferred Debits			7,766
	1548-RCVASTR			279,351
	1550-LV Variance Account			-178,168
	1555-Smart Meters Capital Variance Account			-150,152
	1556-Smart Meters OM&A Variance Account			11,801
	1562-Deferred Payments in Lieu of Taxes			0
	1565-Conservation and Demand Management Expenditures and Recoveries			-89,824
	1566-CDM Contra Account			-1,450
	1570-Qualifying Transition Costs			0
	1571-Pre-market Opening Energy Variance			-333,319
	1580-RSVAWMS			-1,948,648
1582-RSVAONE-TIME			328,493	
1584-RSVANW			604,755	

FinStmt		BS	OK?	YES
Sum of Amount				
GroupDesc	AcctDesc		Total	
1200-Other Assets and Deferred Charges	1586-RSVACN		-757,789	
	1588-RSVAPOWER		726,868	
	1590-Recovery of Regulatory Asset Balances		571,159	
1200-Other Assets and Deferred Charges Total			-822,607	
1300-Intangible Plant	1610-Miscellaneous Intangible Plant		0	
1300-Intangible Plant Total			0	
1450-Distribution Plant	1805-Land		208,241	
	1806-Land Rights		0	
	1808-Buildings and Fixtures		1,192,568	
	1810-Leasehold Improvements		0	
	1815-Transformer Station Equipment - Normally Primary above 50 kV		4,469,541	
	1820-Distribution Station Equipment - Normally Primary below 50 kV		140,683	
	1830-Poles, Towers and Fixtures		11,920,113	
	1835-Overhead Conductors and Devices		10,775,413	
	1840-Underground Conduit		10,375,083	
	1845-Underground Conductors and Devices		11,347,730	
	1850-Line Transformers		13,265,394	
1855-Services		792,032		
1860-Meters		6,957,346		
1450-Distribution Plant Total			71,444,145	
1500-General Plant	1905-Land		0	
	1906-Land Rights		0	
	1908-Buildings and Fixtures		0	
	1910-Leasehold Improvements		0	
	1915-Office Furniture and Equipment		0	
	1920-Computer Equipment - Hardware		0	
	1925-Computer Software		0	
	1930-Transportation Equipment		2,597,774	
	1935-Stores Equipment		0	
	1940-Tools, Shop and Garage Equipment		105,073	
	1945-Measurement and Testing Equipment		0	
1950-Power Operated Equipment		0		

FinStmnt		BS	OK?	YES
Sum of Amount				
GroupDesc	AcctDesc		Total	
1500-General Plant	1955-Communication Equipment		1,176	
	1960-Miscellaneous Equipment		0	
	1965-Water Heater Rental Units		0	
	1970-Load Management Controls - Customer Premises		547,972	
	1975-Load Management Controls - Utility Premises		0	
	1980-System Supervisory Equipment		200,000	
	1985-Sentinel Lighting Rental Units		0	
	1995-Contributions and Grants - Credit		-1,377,714	
1500-General Plant Total			2,074,281	
1550-Other Capital Assets	2005-Property Under Capital Leases		0	
	2055-Construction Work in Progress--Electric		0	
1550-Other Capital Assets Total			0	
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment		-16,967,097	
	2120-Accumulated Amortization of Electric Utility Plant - Intangibles		12,023	
1600-Accumulated Amortization Total			-16,955,074	
1650-Current Liabilities	2205-Accounts Payable		-1,379,507	
	2208-Customer Credit Balances		-500,000	
	2210-Current Portion of Customer Deposits		-421,824	
	2220-Miscellaneous Current and Accrued Liabilities		-8,592,500	
	2240-Accounts Payable to Associated Companies		-1,369,475	
	2250-Debt Retirement Charges(DRC) Payable		-600,000	
	2260-Current Portion of Long Term Debt		0	
	2268-Accrued Interest on Long Term Debt		-2,830,143	
	2292-Payroll Deductions / Expenses Payable		-8,000	
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.		-450,700	
1650-Current Liabilities Total			-16,152,149	
1700-Non-Current Liabilities	2306-Employee Future Benefits		-443,038	
	2310-Vested Sick Leave Liability		-69,756	
	2335-Long Term Customer Deposits		-2,057,317	
	2405-Other Regulatory Liabilities		0	
1700-Non-Current Liabilities Total			-2,570,111	
1800-Long-Term Debt	2525-Term Bank Loans - Long Term Portion		-9,212,000	

FinStmnt		BS	OK?	YES
Sum of Amount				
GroupDesc	AcctDesc		Total	
1800-Long-Term Debt	2550-Advances from Associated Companies		-24,189,168	
1800-Long-Term Debt Total			-33,401,168	
1850-Shareholders' Equity	3005-Common Shares Issued		-22,437,505	
	3045-Unappropriated Retained Earnings		-4,795,294	
	3046-Balance Transferred From Income		-1,039,507	
	3049-Dividends Payable-Common Shares		0	
	3055-Adjustment to Retained Earnings		-1,415,453	
1850-Shareholders' Equity Total			-29,687,760	
Grand Total			-0	

FinStmt	PL	
Sum of Amount		
GroupDesc	AcctDesc	Total
3000-Sales of Electricity	4006-Residential Energy Sales	-59,328,681
	4025-Street Lighting Energy Sales	0
	4030-Sentinel Lighting Energy Sales	0
	4035-General Energy Sales	0
	4050-Revenue Adjustment	1,521,265
	4055-Energy Sales for Resale	0
	4062-Billed WMS	-6,436,822
	4066-Billed NW	-11,193,231
	4068-Billed CN	0
	4075-Billed-LV	0
3000-Sales of Electricity Total		-75,437,469
3050-Revenues From Services - Distirbution	4080-Distribution Services Revenue	-15,254,831
	4082-Retail Services Revenues	-73,859
	4084-Service Transaction Requests (STR) Revenues	-48,778
3050-Revenues From Services - Distirbution Total		-15,377,468
3100-Other Operating Revenues	4210-Rent from Electric Property	-102,626
	4220-Other Electric Revenues	-5,784
	4225-Late Payment Charges	-107,332
	4235-Miscellaneous Service Revenues	-664,592
3100-Other Operating Revenues Total		-880,334
3150-Other Income & Deductions	4355-Gain on Disposition of Utility and Other Property	0
	4375-Revenues from Non-Utility Operations	-585,883
	4380-Expenses of Non-Utility Operations	532,576
3150-Other Income & Deductions Total		-53,307
3200-Investment Income	4405-Interest and Dividend Income	-283,954
3200-Investment Income Total		-283,954
3350-Power Supply Expenses	4705-Power Purchased	59,218,767
	4708-Charges-WMS	6,207,158
	4712-Charges-One-Time	0
	4714-Charges-NW	10,011,545
	4715-System Control and Load Dispatching	0
	4716-Charges-CN	0
3350-Power Supply Expenses Total		75,437,470
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	284,763

FinStmnt	PL
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Sum of Amount		Total
GroupDesc	AcctDesc	
3500-Distribution Expenses - Operation	5010-Load Dispatching	57,747
	5012-Station Buildings and Fixtures Expense	36,656
	5014-Transformer Station Equipment - Operation Labour	3,092
	5015-Transformer Station Equipment - Operation Supplies and Expenses	31,246
	5016-Distribution Station Equipment - Operation Labour	2,275
	5017-Distribution Station Equipment - Operation Supplies and Expenses	3,426
	5020-Overhead Distribution Lines and Feeders - Operation Labour	3,676
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	19,562
	5030-Overhead Subtransmission Feeders - Operation	0
	5035-Overhead Distribution Transformers- Operation	16,334
	5040-Underground Distribution Lines and Feeders - Operation Labour	2,950
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	19,228
	5050-Underground Subtransmission Feeders - Operation	0
	5055-Underground Distribution Transformers - Operation	3,641
	5060-Street Lighting and Signal System Expense	0
	5065-Meter Expense	545,927
	5070-Customer Premises - Operation Labour	1,541
	5075-Customer Premises - Materials and Expenses	0
	5085-Miscellaneous Distribution Expense	130,949
	5095-Overhead Distribution Lines and Feeders - Rental Paid	13,913
3500-Distribution Expenses - Operation Total		1,176,926
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	302,980
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	4,394
	5114-Maintenance of Distribution Station Equipment	14,587
	5120-Maintenance of Poles, Towers and Fixtures	169,121
	5125-Maintenance of Overhead Conductors and Devices	209,803
	5130-Maintenance of Overhead Services	215,368
	5135-Overhead Distribution Lines and Feeders - Right of Way	355,047
	5145-Maintenance of Underground Conduit	60,364
	5150-Maintenance of Underground Conductors and Devices	127,553
	5155-Maintenance of Underground Services	238,880
	5160-Maintenance of Line Transformers	171,919
	5175-Maintenance of Meters	0
	5195-Maintenance of Other Installations on Customer Premises	0

FinStmnt	PL	
Sum of Amount		
GroupDesc	AcctDesc	Total
3550-Distribution Expenses - Maintenance Total		1,870,016
3650-Billing and Collecting	5305-Supervision	146,974
	5310-Meter Reading Expense	424,086
	5315-Customer Billing	509,230
	5320-Collecting	326,610
	5330-Collection Charges	2,450
	5335-Bad Debt Expense	200,000
	5340-Miscellaneous Customer Accounts Expenses	536,497
3650-Billing and Collecting Total		2,145,847
3700-Community Relations	5405-Supervision	0
	5410-Community Relations - Sundry	123,966
	5415-Energy Conservation	51,150
	5420-Community Safety Program	15,024
3700-Community Relations Total		190,140
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	410,353
	5610-Management Salaries and Expenses	684,152
	5615-General Administrative Salaries and Expenses	725,408
	5620-Office Supplies and Expenses	75,746
	5630-Outside Services Employed	79,000
	5645-Employee Pensions and Benefits	111,389
	5650-Franchise Requirements	54,247
	5655-Regulatory Expenses	207,954
	5660-General Advertising Expenses	25,500
	5665-Miscellaneous General Expenses	172,618
	5670-Rent	0
	5675-Maintenance of General Plant	0
	5680-Electrical Safety Authority Fees	18,000
	5685-Independent Market Operator Fees and Penalties	70,000
	5695-Smart Meters OM&A Contra	0
3800-Administrative and General Expenses Total		2,634,367
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	2,793,368
	5710-Amortization of Limited Term Electric Plant	0
	5715-Amortization of Intangibles and Other Electric Plant	-12,023
3850-Amortization Expense Total		2,781,345

FinStmnt	PL
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Sum of Amount		Total
GroupDesc	AcctDesc	Total
3900-Interest Expense	6005-Interest on Long Term Debt	385,824
	6030-Interest on Debt to Associated Companies	1,511,823
	6035-Other Interest Expense	162,920
	6042-Allowance For Other Funds Used During Construction	-20,459
3900-Interest Expense Total		2,040,108
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	12,459
3950-Taxes Other Than Income Taxes Total		12,459
4000-Income Taxes	6110-Income Taxes	2,704,197
4000-Income Taxes Total		2,704,197
4100-Extraordinary & Other Items	6205-Donations	150
4100-Extraordinary & Other Items Total		150
Grand Total		-1,039,507

FinStmnt	BS	OK?	YES
Sum of Amount			
GroupDesc	AcctDesc		Total
1050-Current Assets	1005-Cash		9,054,639
	1040-Other Special Deposits		441,333
	1100-Customer Accounts Receivable		7,182,847
	1102-Accounts Receivable - Services		1,000
	1104-Accounts Receivable - Recoverable Work		440,000
	1110-Other Accounts Receivable		104,200
	1120-Accrued Utility Revenues		8,802,173
	1130-Accumulated Provision for Uncollectible Accounts--Credit		-410,000
	1150-Rents Receivable		13,000
	1180-Prepayments		310,108
	1190-Miscellaneous Current and Accrued Assets		0
1050-Current Assets Total			25,939,300
1100-Inventory	1330-Plant Materials and Operating Supplies		2,393,830
1100-Inventory Total			2,393,830
1150-Non-Current Assets	1410-Other Special or Collateral Funds		2,152,467
1150-Non-Current Assets Total			2,152,467
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets		92,739
	1518-RCVARetail		22,058
	1520-Power Purchase Variance Account		0
	1525-Miscellaneous Deferred Debits		8,141
	1548-RCVASTR		341,138
	1550-LV Variance Account		-224,463
	1555-Smart Meters Capital Variance Account		-141,548
	1556-Smart Meters OM&A Variance Account		12,306
	1562-Deferred Payments in Lieu of Taxes		0
	1565-Conservation and Demand Management Expenditures and Recoveries		-89,824
	1566-CDM Contra Account		-1,450
	1570-Qualifying Transition Costs		0
	1571-Pre-market Opening Energy Variance		-333,319
	1580-RSVAWMS		-3,391,190
1582-RSVAONE-TIME		342,111	
1584-RSVANW		637,884	

FinStmnt		BS	OK?	YES	
Sum of Amount					
GroupDesc	AcctDesc		Total		
1200-Other Assets and Deferred Charges	1586-RSVACN		-1,104,504		
	1588-RSVAPOWER		912,069		
	1590-Recovery of Regulatory Asset Balances		891,201		
1200-Other Assets and Deferred Charges Total			-2,026,651		
1300-Intangible Plant	1610-Miscellaneous Intangible Plant		0		
1300-Intangible Plant Total			0		
1450-Distribution Plant	1805-Land		208,241		
	1806-Land Rights		0		
	1808-Buildings and Fixtures		1,192,568		
	1810-Leasehold Improvements		0		
	1815-Transformer Station Equipment - Normally Primary above 50 kV		4,469,541		
	1820-Distribution Station Equipment - Normally Primary below 50 kV		140,683		
	1830-Poles, Towers and Fixtures		12,020,875		
	1835-Overhead Conductors and Devices		11,902,709		
	1840-Underground Conduit		10,663,516		
	1845-Underground Conductors and Devices		13,338,387		
1450-Distribution Plant Total	1850-Line Transformers		13,936,561		
	1855-Services		1,173,813		
	1860-Meters		7,437,807		
				76,484,701	
	1500-General Plant	1905-Land		0	
		1906-Land Rights		0	
1908-Buildings and Fixtures			0		
1910-Leasehold Improvements			0		
1915-Office Furniture and Equipment			0		
1920-Computer Equipment - Hardware			0		
1925-Computer Software			220,000		
1930-Transportation Equipment			2,802,774		
1935-Stores Equipment			0		
1940-Tools, Shop and Garage Equipment			135,073		
1500-General Plant Total	1945-Measurement and Testing Equipment		0		
	1950-Power Operated Equipment		0		

FinStmt		BS		OK?	YES
Sum of Amount					
GroupDesc	AcctDesc		Total		
1500-General Plant	1955-Communication Equipment		1,176		
	1960-Miscellaneous Equipment		0		
	1965-Water Heater Rental Units		0		
	1970-Load Management Controls - Customer Premises		547,972		
	1975-Load Management Controls - Utility Premises		0		
	1980-System Supervisory Equipment		390,000		
	1985-Sentinel Lighting Rental Units		0		
	1995-Contributions and Grants - Credit		-1,752,114		
1500-General Plant Total			2,344,881		
1550-Other Capital Assets	2005-Property Under Capital Leases		0		
	2055-Construction Work in Progress--Electric		-0		
1550-Other Capital Assets Total			-0		
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment		-20,241,746		
	2120-Accumulated Amortization of Electric Utility Plant - Intangibles		12,023		
1600-Accumulated Amortization Total			-20,229,723		
1650-Current Liabilities	2205-Accounts Payable		-1,726,819		
	2208-Customer Credit Balances		-500,000		
	2210-Current Portion of Customer Deposits		-441,333		
	2220-Miscellaneous Current and Accrued Liabilities		-8,592,500		
	2240-Accounts Payable to Associated Companies		-1,413,019		
	2250-Debt Retirement Charges(DRC) Payable		-600,000		
	2260-Current Portion of Long Term Debt		0		
	2268-Accrued Interest on Long Term Debt		-2,523,646		
	2292-Payroll Deductions / Expenses Payable		-8,100		
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.		-337,553		
1650-Current Liabilities Total			-16,142,970		
1700-Non-Current Liabilities	2306-Employee Future Benefits		-439,005		
	2310-Vested Sick Leave Liability		-71,300		
	2335-Long Term Customer Deposits		-2,152,467		
	2405-Other Regulatory Liabilities		0		
1700-Non-Current Liabilities Total			-2,662,772		
1800-Long-Term Debt	2525-Term Bank Loans - Long Term Portion		-11,950,520		

FinStmt		BS		
				OK? YES
Sum of Amount				
GroupDesc	AcctDesc			Total
1800-Long-Term Debt	2550-Advances from Associated Companies			-24,189,168
1800-Long-Term Debt Total				-36,139,688
1850-Shareholders' Equity	3005-Common Shares Issued			-22,437,505
	3045-Unappropriated Retained Earnings			-5,834,801
	3046-Balance Transferred From Income			-2,425,617
	3049-Dividends Payable-Common Shares			0
	3055-Adjustment to Retained Earnings			-1,415,453
1850-Shareholders' Equity Total				-32,113,377
Grand Total				-0

FinStmnt	PL
----------	----

Sum of Amount		Total
GroupDesc	AcctDesc	
3000-Sales of Electricity	4006-Residential Energy Sales	-59,480,167
	4025-Street Lighting Energy Sales	0
	4030-Sentinel Lighting Energy Sales	0
	4035-General Energy Sales	0
	4050-Revenue Adjustment	1,337,549
	4055-Energy Sales for Resale	0
	4062-Billed WMS	-6,465,236
	4066-Billed NW	-11,162,607
	4068-Billed CN	0
	4075-Billed-LV	0
3000-Sales of Electricity Total		-75,770,461
3050-Revenues From Services - Distirbution	4080-Distribution Services Revenue	-16,653,214
	4082-Retail Services Revenues	-63,000
	4084-Service Transaction Requests (STR) Revenues	-49,000
3050-Revenues From Services - Distirbution Total		-16,765,214
3100-Other Operating Revenues	4210-Rent from Electric Property	-91,925
	4220-Other Electric Revenues	-5,000
	4225-Late Payment Charges	-95,172
	4235-Miscellaneous Service Revenues	-679,232
3100-Other Operating Revenues Total		-871,329
3150-Other Income & Deductions	4355-Gain on Disposition of Utility and Other Property	0
	4375-Revenues from Non-Utility Operations	0
	4380-Expenses of Non-Utility Operations	0
3150-Other Income & Deductions Total		0
3200-Investment Income	4405-Interest and Dividend Income	-439,000
3200-Investment Income Total		-439,000
3350-Power Supply Expenses	4705-Power Purchased	59,480,167
	4708-Charges-WMS	6,234,557
	4712-Charges-One-Time	0
	4714-Charges-NW	10,055,737
	4715-System Control and Load Dispatching	0
	4716-Charges-CN	0
3350-Power Supply Expenses Total		75,770,461
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	266,919

FinStmnt	PL
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Sum of Amount		
GroupDesc	AcctDesc	Total
3500-Distribution Expenses - Operation	5010-Load Dispatching	17,887
	5012-Station Buildings and Fixtures Expense	39,832
	5014-Transformer Station Equipment - Operation Labour	6,778
	5015-Transformer Station Equipment - Operation Supplies and Expenses	55,950
	5016-Distribution Station Equipment - Operation Labour	2,140
	5017-Distribution Station Equipment - Operation Supplies and Expenses	3,946
	5020-Overhead Distribution Lines and Feeders - Operation Labour	3,298
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	15,081
	5030-Overhead Subtransmission Feeders - Operation	0
	5035-Overhead Distribution Transformers- Operation	16,167
	5040-Underground Distribution Lines and Feeders - Operation Labour	1,139
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	20,669
	5050-Underground Subtransmission Feeders - Operation	0
	5055-Underground Distribution Transformers - Operation	3,594
	5060-Street Lighting and Signal System Expense	0
	5065-Meter Expense	494,376
	5070-Customer Premises - Operation Labour	6,531
	5075-Customer Premises - Materials and Expenses	0
	5085-Miscellaneous Distribution Expense	129,239
	5095-Overhead Distribution Lines and Feeders - Rental Paid	6,866
3500-Distribution Expenses - Operation Total		1,090,412
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	306,914
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	4,337
	5114-Maintenance of Distribution Station Equipment	17,703
	5120-Maintenance of Poles, Towers and Fixtures	167,336
	5125-Maintenance of Overhead Conductors and Devices	212,429
	5130-Maintenance of Overhead Services	219,810
	5135-Overhead Distribution Lines and Feeders - Right of Way	364,402
	5145-Maintenance of Underground Conduit	72,896
	5150-Maintenance of Underground Conductors and Devices	121,982
	5155-Maintenance of Underground Services	222,899
	5160-Maintenance of Line Transformers	173,973
	5175-Maintenance of Meters	0
	5195-Maintenance of Other Installations on Customer Premises	0

FinStmt		PL	
Sum of Amount			
GroupDesc	AcctDesc		Total
3550-Distribution Expenses - Maintenance Total			1,884,681
3650-Billing and Collecting	5305-Supervision		147,522
	5310-Meter Reading Expense		405,512
	5315-Customer Billing		509,848
	5320-Collecting		327,828
	5330-Collection Charges		2,459
	5335-Bad Debt Expense		200,000
	5340-Miscellaneous Customer Accounts Expenses		709,340
3650-Billing and Collecting Total			2,302,509
3700-Community Relations	5405-Supervision		0
	5410-Community Relations - Sundry		125,171
	5415-Energy Conservation		0
	5420-Community Safety Program		13,920
3700-Community Relations Total			139,091
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses		429,070
	5610-Management Salaries and Expenses		723,218
	5615-General Administrative Salaries and Expenses		726,087
	5620-Office Supplies and Expenses		52,654
	5630-Outside Services Employed		179,500
	5645-Employee Pensions and Benefits		110,367
	5650-Franchise Requirements		53,871
	5655-Regulatory Expenses		215,000
	5660-General Advertising Expenses		26,000
	5665-Miscellaneous General Expenses		187,617
	5670-Rent		0
	5675-Maintenance of General Plant		0
	5680-Electrical Safety Authority Fees		20,000
	5685-Independent Market Operator Fees and Penalties		60,000
5695-Smart Meters OM&A Contra		0	
3800-Administrative and General Expenses Total			2,783,384
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment		3,027,657
	5710-Amortization of Limited Term Electric Plant		0
	5715-Amortization of Intangibles and Other Electric Plant		0
3850-Amortization Expense Total			3,027,657

FinStmnt	PL
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Sum of Amount		Total
GroupDesc	AcctDesc	
3900-Interest Expense	6005-Interest on Long Term Debt	585,444
	6030-Interest on Debt to Associated Companies	1,511,823
	6035-Other Interest Expense	305,217
	6042-Allowance For Other Funds Used During Construction	-18,055
3900-Interest Expense Total		2,384,429
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	12,298
3950-Taxes Other Than Income Taxes Total		12,298
4000-Income Taxes	6110-Income Taxes	2,025,315
4000-Income Taxes Total		2,025,315
4100-Extraordinary & Other Items	6205-Donations	150
4100-Extraordinary & Other Items Total		150
Grand Total		-2,425,617

ATTACHMENT M

REFERENCE: OEB STAFF QUESTION 8.1

RUN #:	Rate classes	Weather station used for normalization	Test Year												
			2004												
1	Residential	Windsor	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
2	GS>50KW		31,046,022	23,926,387	23,445,403	20,984,978	20,517,459	19,878,003	24,636,463	24,282,449	21,953,803	20,919,172	20,934,604	21,550,268	280,077,031
3	Street Lighting		49,245,998	51,202,972	53,033,587	48,656,876	48,572,333	51,981,533	49,438,884	50,188,072	51,905,031	49,400,286	51,851,255	47,389,975	601,947,824
4	Sentinel Lighting		690,375	584,224	559,337	474,718	429,590	387,304	414,350	472,118	526,292	621,526	659,953	708,728	6,528,516
5	GS<50 KW		33,736	32,784	32,831	33,475	33,475	33,475	33,236	33,141	33,156	33,236	33,234	32,526	388,304
6	Standby		20,000	13,269	8,289	150,004	127,461	58,877	27,230	168,999	43,415	4,258	21,320	135,757	778,877
Monthly kWh by class (with actual weather)															
1	Residential	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	
2	GS>50KW	30,380,628	24,115,005	24,077,903	21,172,622	20,532,687	20,810,160	25,508,454	25,475,374	21,513,800	21,382,057	21,526,725	27,504,161	284,000,199	
3	Street Lighting	49,031,746	51,377,090	53,017,474	49,030,098	48,587,600	53,205,135	50,581,078	51,752,906	51,287,567	49,827,596	52,397,866	47,327,410	606,623,873	
4	Sentinel Lighting	690,375	584,224	559,337	474,718	429,590	387,304	414,350	472,118	526,292	621,526	659,953	708,728	6,528,516	
5	GS<50 KW	33,736	32,784	32,831	33,475	33,475	33,475	33,236	33,141	33,156	33,236	33,234	32,526	388,304	
6	Standby	9,348,689	7,473,644	8,401,980	5,950,918	8,768,503	8,768,229	10,655,977	9,767,330	8,390,933	9,262,968	8,342,881	11,735,915	104,878,351	
Monthly kWh by class (with normalized weather)															
1	Residential	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	
2	GS>50KW	30,380,628	24,115,005	24,077,903	21,172,622	20,532,687	20,810,160	25,508,454	25,475,374	21,513,800	21,382,057	21,526,725	27,504,161	284,000,199	
3	Street Lighting	49,031,746	51,377,090	53,017,474	49,030,098	48,587,600	53,205,135	50,581,078	51,752,906	51,287,567	49,827,596	52,397,866	47,327,410	606,623,873	
4	Sentinel Lighting	690,375	584,224	559,337	474,718	429,590	387,304	414,350	472,118	526,292	621,526	659,953	708,728	6,528,516	
5	GS<50 KW	33,736	32,784	32,831	33,475	33,475	33,475	33,236	33,141	33,156	33,236	33,234	32,526	388,304	
6	Standby	20,000	13,269	8,289	150,004	127,461	58,877	27,230	168,999	43,415	4,258	21,320	135,757	778,877	
Residential class information															
Equipment saturation		13%													
Electric space heating		14%													
Air conditioning		53%													
Baseload		100%													
General service >50KW															
		2004 kWh (Actual)		2004 kWh (Weather Corrected)											
Weather sensitive load		187,587,740		192,243,797											
Non-weather sensitive load		414,380,076		414,380,076											
TOTAL		601,947,824		606,623,873											
Standby															
		2004 kWh (Actual)		2004 kWh (Weather Corrected)											
Weather sensitive load		0		0											
Non-weather sensitive load		778,877		778,877											
TOTAL		778,877		778,877											

ATTACHMENT N

REFERENCE: OEB STAFF QUESTION 9.1a) i & ii

LOSS ADJUSTMENT FACTOR CALCULATION

	2002	2003	2004	2005	2006
A "Wholesale" kWh (IESO)	944,383,346	947,648,812	989,156,247	1,023,183,440	1,022,782,846
B Wholesale kWh for Large Use customer(s) (IESO)	0	0	0	0	0
C Net "Wholesale" kWh (A)-(B)	944,383,346	947,648,812	989,156,247	1,023,183,440	1,022,782,846
D Retail kWh (Distributor)	907,624,411	914,155,229	954,965,318	983,345,833	990,086,984
E Retail kWh for Large Use Customer(s) (1% loss)	0	0	0	0	0
F Net "Retail" kWh (D)-(E)	907,624,411	914,155,229	954,965,318	983,345,833	990,086,984
G Loss Factor [(C)/(F)]	1.04050016	1.03663884	1.03580332	1.04051231	1.03302322
H Distribution Loss Adjustment Factor					1.03730

<u>Total Utility Loss Adjustment Factor</u>	<u>LAF</u>
Supply Facility Loss Factor	1.0045
Distribution - Secondary Metered Customer < 5,000kW	1.0326
Distribution - Primary Metered Customer < 5,000kW	1.0223

Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0373
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0269

ATTACHMENT O

REFERENCE: OEB STAFF QUESTION 10.2

**COST ALLOCATION INFORMATION FILING
BRANTFORD POWER INC.
2006 EDR EB-2005-0342**

MANAGER'S SUMMARY

Brantford Power Inc.'s Cost Allocation Information Filing comprises the following:

- Part 1. Manager's Summary
- Part 2. Filing Summary. Appendix 1.1 and Addendum to Appendix 1.1
- Part 3. Filing Summary. Appendix 1.1 and Addendum to Appendix 1.1 with confidential information removed
- Part 4. Model Sheets I2, I4 and O1. Run 1
- Part 5. Model Sheets I2, I4 and O1. Run 2.
- Part 6. Cost Allocation Model. Run1
- Part 7. Cost Allocation Model. Run 2
- Part 8. Cost Allocation Model. Run 2 with confidential information removed.

In accordance with the guidelines for treatment of confidential third party information, Brantford Power advises that the informational filing contains confidential third party information in both the Filing Summary and Run 2 of the Model pertaining to large user and load displacement generator [standby power] rate classifications as there are two or less customers in these classification.

With respect to the Cost Allocation Information filing, Brantford Power offers the following comments:

1. Since the 2006 EDR test year, Brantford Power notes the following changes to its operations, discussed in greater detail in the Filing Summary, that would materially impact rate classification statistics:
 - Addition of a large customer [Filing Questions 3 and 50]
 - Change to Brantford Power's capitalization policy and practices [Filing Question 53]
 - Changes in accounting treatment for Contributed Capital [Filing Question 68]
 - Changes in accounting treatment for Services [Filing Question 104]
 - Changes in accounting treatment for Interval Meter Reading Costs [Filing Question 52], and
 - Implementation of CATV Battery Mats.
2. Future cost allocation studies would benefit from more specific direction in the Accounting Procedures Handbook and the Uniform System of Accounts with respect to the appropriate accounting treatment for cost allocation purposes.
3. Overall, Brantford Power is of the view that the Cost Allocation Information Filing provides valuable information and analysis for its future system planning and design activities.

CONTACT INFORMATION:

Mr. George Mychailenko
Chief Executive Officer
Brantford Power Inc.
84 Market Street
Brantford ON
N3T 3N8
519 751-3522 Ext. 3226
gmychailenko@brantford.ca

Heather Wyatt, Manager of Regulatory
Compliance and Governance
Brantford Power Inc.
84 Market Street
Brantford ON
N3T 3N8
519 751-3522 Ext. 3269
hwyatt@brantford.ca



Ontario Energy Board
2006 Cost Allocation Information Filing
Sheet 1: Utility Information Sheet

Name of LDC:

License Number:

EDR 2006 EB Number: **Cost Allocation EB Number:** ← drop-down menu

Date of Submission: **Version:** 1.2

Contact Information

Name:

Title:

Phone Number:

E-Mail Address:

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**** Please Note: Colour Coding Legend ****

- Input Cells
- Output Cells
- Exhibition
- Brought Forward
- Calculation
- Default Numbers
- Diagnostic

Brief Description of Each Worksheet's Function

Worksheet	Description	Function
INPUTS		
I1	Intro	Brief explanation of what the pages do.
I2	LDC data and Classes	Enter LDC specific information and number of classes etc.
I3	TB Data	Balance from approved 2006 EDR Trial Balance.
I4	BO ASSETS	Break out assets into detail functions - both deliver, primary and secondary
I5	Misc Data	Input for miscellaneous data where necessary - TBD
I6	Customer Data	Input customer related data for generating customer allocators
I7.1	Meter Capital	Input meter related data for calculating capital costs weighting factors
I7.2	Meter Reading	Input meter related data for calculating meter reading weighting factors
I8	Demand Data	Input demand allocators using load data and making LDC specific adjustments
OUTPUTS		
O1	Revenue to cost	Output showing revenue to cost ratios, inter class subsidy etc.
O2	Fixed Charge	Output showing the range for the basic Customer charge - TBD
O2.1	Line Transformer PLCC Adjustment	
O2.2	Primary Cost PLCC Adjustment	
O2.3	Secondary Cost PLCC Adjustment	
O3.1	Line Tran Unit Cost	
O3.2	Substat Tran Unit Cost	
O3.3	Primary Cost Pool	
O3.4	Secondary Cost Pool	
O3.5	UG Metering Credit	
O4	Summary by Class	Output showing summary of all allocation by class and by US of A
O5	Detail by Class	Output showing details of individual allocation by class and by US/A
O6	Source Data for E2	
O7	Amortization	
EXHIBITS		
E1	Categorization	Exhibit showing how costs are categorized
E2	Allocation Factors	Exhibit summarizing all allocation factors created in I5 to I8 and present the findings in percentages
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

1. GENERAL



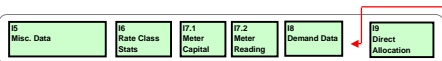
2. LDC INPUT - Rate Classes



3. LDC INPUT - Financial Data



4. LDC INPUT - Customer Data and Operating Stats



5. MODEL PROCESS - Categorization - OEB Defaults



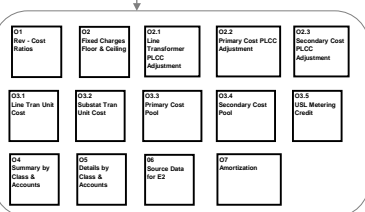
6. MODEL PROCESS - Allocators calculated from 4.



7. MODEL PROCESS - Detail Cost Elements by Rate Class



8. MODEL OUTPUT - Summaries by Rate Class





2006 Cost Allocation Information Filing

Brantford Power Inc.

EB-2005-0342 EB-2007-0001

Tuesday, January 30, 2007

Sheet 12 Class Selection - Second Run

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

Click for Drop-Down
Menu

If desired, provide a summary of this run
(40 characters max.)

Second Run	
------------	--

		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		YES
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		YES
11	Back-up/Standby Power		YES
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

Update

**** Space available for additional information about this run**



2006 Cost Allocation Information Filing

Brantford Power Inc.
EB-2005-0342 EB-2007-0001
Tuesday, January 30, 2007

Sheet 13 Trial Balance Data - Second Run

Instructions:

Step 1: Copy 2006 EDR Trial Balance values (Sheet 2-4, Column P17 to P446) to Column D21 of this worksheet. Use the Edit - Paste Special - Values function.

Step 2: Enter the amounts needed to be reclassified to column F.

Step 3: Enter Target Net Income from approved EDR (Sheet 4-1, cell F23)

Step 4: Enter PILs from approved EDR (Sheet 4-2, cell E15)

Step 5: Enter Interest from approved EDR (Sheet 4-1, cell F21)

Step 6: Enter specific service charges offset from approved EDR (Sheet 5-5, cell D19)

Step 7: Enter Transformation Ownership Allowance Credit from approved EDR (Sheet 6-3, cell R120)

Step 8: Enter Low Voltage Wheeling Adjustment Credit from approved EDR (Sheet ADJ 3, cell F46)

Step 9: Enter Revenue Requirement from approved EDR (Sheet 5-1, cell F22)

Step 10: Enter Total Rate Base from approved EDR (Sheet 3-1, cell F21)

Step 11: Enter Directly Allocated amounts into column G.

Approved Target Net Income (\$)	\$2,530,275
Approved PILs (\$)	\$1,676,671
Approved Interest (\$)	\$1,713,823
Approved Specific Service Charges (\$)	\$439,085
Approved Transformer Ownership Allowance (\$)	\$515,193
Approved Low Voltage Wheeling Adjustment (\$)	\$104,536
Approved Revenue Requirement (\$)	\$15,911,396
Revenue Requirement to be Used in this model (\$)	\$16,322,053
Approved Rate Base (\$)	\$56,228,334
Rate Base to be Used in this model (\$)	\$56,289,932

From this Sheet	Differences?
\$16,322,053	Rev Req Matches
\$56,289,932	Rate Base Matches

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash					\$0
1010	Cash Advances and Working Funds					\$0
1020	Interest Special Deposits					\$0
1030	Dividend Special Deposits					\$0
1040	Other Special Deposits					\$0
1060	Term Deposits					\$0
1070	Current Investments					\$0
1100	Customer Accounts Receivable					\$0
1102	Accounts Receivable - Services					\$0
1104	Accounts Receivable - Recoverable Work					\$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.					\$0
1110	Other Accounts Receivable					\$0
1120	Accrued Utility Revenues					\$0
1130	Accumulated Provision for Uncollectible Accounts-- Credit					\$0
1140	Interest and Dividends Receivable					\$0
1150	Rents Receivable					\$0
1170	Notes Receivable					\$0
1180	Prepayments					\$0
1190	Miscellaneous Current and Accrued Assets					\$0
1200	Accounts Receivable from Associated Companies					\$0
1210	Notes Receivable from Associated Companies					\$0
1305	Fuel Stock					\$0
1330	Plant Materials and Operating Supplies					\$0
1340	Merchandise					\$0
1350	Other Materials and Supplies					\$0
1405	Long Term Investments in Non-Associated Companies					\$0

1408	Long Term Receivable - Street Lighting Transfer			\$0
1410	Other Special or Collateral Funds			\$0
1415	Sinking Funds			\$0
1425	Unamortized Debt Expense			\$0
1445	Unamortized Discount on Long-Term Debt--Debit			\$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses			\$0
1460	Other Non-Current Assets			\$0
1465	O.M.E.R.S. Past Service Costs			\$0
1470	Past Service Costs - Employee Future Benefits			\$0
1475	Past Service Costs - Other Pension Plans			\$0
1480	Portfolio Investments - Associated Companies			\$0
1485	Investment in Associated Companies - Significant Influence			\$0
1490	Investment in Subsidiary Companies			\$0
1505	Unrecovered Plant and Regulatory Study Costs			\$0
1508	Other Regulatory Assets			\$0
1510	Preliminary Survey and Investigation Charges			\$0
1515	Emission Allowance Inventory			\$0
1516	Emission Allowances Withheld			\$0
1518	RCVARetail			\$0
1520	Power Purchase Variance Account			\$0
1525	Miscellaneous Deferred Debits			\$0
1530	Deferred Losses from Disposition of Utility Plant			\$0
1540	Unamortized Loss on Reacquired Debt			\$0
1545	Development Charge Deposits/ Receivables			\$0
1548	RCVASTR			\$0
1560	Deferred Development Costs			\$0
1562	Deferred Payments in Lieu of Taxes			\$0
1563	Account 1563 - Deferred PILs Contra Account			\$0
1565	Conservation and Demand Management Expenditures and Recoveries			\$548,247
1570	Qualifying Transition Costs			\$198,428
1571	Pre-market Opening Energy Variance			(\$20,742)
1572	Extraordinary Event Costs			\$0
1574	Deferred Rate Impact Amounts			\$0
1580	RSVAWMS			\$0
1582	RSVAONE-TIME			\$0
1584	RSVANW			(\$3,435)
1586	RSVACN			\$60,208
1588	RSVAPOWER			(\$616,559)
1590	Recovery of Regulatory Asset Balances			\$0
1605	Electric Plant in Service - Control Account			\$0
1606	Organization			\$0
1608	Franchises and Consents			\$0
1610	Miscellaneous Intangible Plant			\$0
1615	Land			\$0
1616	Land Rights			\$0
1620	Buildings and Fixtures			\$0
1630	Leasehold Improvements			\$0
1635	Boiler Plant Equipment			\$0
1640	Engines and Engine-Driven Generators			\$0
1645	Turbogenerator Units			\$0
1650	Reservoirs, Dams and Waterways			\$0
1655	Water Wheels, Turbines and Generators			\$0
1660	Roads, Railroads and Bridges			\$0
1665	Fuel Holders, Producers and Accessories			\$0
1670	Prime Movers			\$0
1675	Generators			\$0
1680	Accessory Electric Equipment			\$0
1685	Miscellaneous Power Plant Equipment			\$0
1705	Land			\$0
1706	Land Rights			\$0
1708	Buildings and Fixtures			\$0
1710	Leasehold Improvements			\$0
1715	Station Equipment			\$0
1720	Towers and Fixtures			\$0
1725	Poles and Fixtures			\$0
1730	Overhead Conductors and Devices			\$0
1735	Underground Conduit			\$0
1740	Underground Conductors and Devices			\$0
1745	Roads and Trails			\$0
1805	Land			\$52,064
1806	Land Rights			\$0
1808	Buildings and Fixtures			\$129,182
1810	Leasehold Improvements			\$0
1815	Transformer Station Equipment - Normally Primary above 50 kV			\$3,174,688
1820	Distribution Station Equipment - Normally Primary below 50 kV			\$140,683
1825	Storage Battery Equipment			\$0
1830	Poles, Towers and Fixtures			\$9,367,321
1835	Overhead Conductors and Devices			\$7,025,490
1840	Underground Conduit			\$7,998,226
1845	Underground Conductors and Devices			\$7,334,490
1850	Line Transformers			\$10,253,676
1855	Services			\$0
1860	Meters			\$4,922,182
1865	Other Installations on Customer's Premises			\$0
1870	Leased Property on Customer Premises			\$0
1875	Street Lighting and Signal Systems			\$0

1905	Land				\$0
1906	Land Rights				\$0
1908	Buildings and Fixtures				\$0
1910	Leasehold Improvements				\$0
1915	Office Furniture and Equipment				\$0
1920	Computer Equipment - Hardware				\$0
1925	Computer Software				\$0
1930	Transportation Equipment				\$1,519,070
1935	Stores Equipment				\$0
1940	Tools, Shop and Garage Equipment				\$54,995
1945	Measurement and Testing Equipment				\$0
1950	Power Operated Equipment				\$0
1955	Communication Equipment				\$0
1960	Miscellaneous Equipment				\$0
1965	Water Heater Rental Units				\$0
1970	Load Management Controls - Customer Premises				\$547,972
1975	Load Management Controls - Utility Premises				\$0
1980	System Supervisory Equipment				\$0
1985	Sentinel Lighting Rental Units				\$0
1990	Other Tangible Property				\$0
1995	Contributions and Grants - Credit				\$0
2005	Property Under Capital Leases				(\$193,168)
2010	Electric Plant Purchased or Sold				\$0
2020	Experimental Electric Plant Unclassified				\$0
2030	Electric Plant and Equipment Leased to Others				\$0
2040	Electric Plant Held for Future Use				\$0
2050	Completed Construction Not Classified--Electric				\$0
2055	Construction Work in Progress--Electric				\$386,336
2060	Electric Plant Acquisition Adjustment				\$0
2065	Other Electric Plant Adjustment				\$0
2070	Other Utility Plant				\$0
2075	Non-Utility Property Owned or Under Capital Leases				\$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment				(\$7,319,534)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles				\$0
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment				\$0
2160	Accumulated Amortization of Other Utility Plant				\$0
2180	Accumulated Amortization of Non-Utility Property				\$0
2205	Accounts Payable				\$0
2208	Customer Credit Balances				\$0
2210	Current Portion of Customer Deposits				\$0
2215	Dividends Declared				\$0
2220	Miscellaneous Current and Accrued Liabilities				\$0
2225	Notes and Loans Payable				\$0
2240	Accounts Payable to Associated Companies				\$0
2242	Notes Payable to Associated Companies				\$0
2250	Debt Retirement Charges(DRC) Payable				\$0
2252	Transmission Charges Payable				\$0
2254	Electrical Safety Authority Fees Payable				\$0
2256	Independent Market Operator Fees and Penalties Payable				\$0
2260	Current Portion of Long Term Debt				\$0
2262	Ontario Hydro Debt - Current Portion				\$0
2264	Pensions and Employee Benefits - Current Portion				\$0
2268	Accrued Interest on Long Term Debt				\$0
2270	Matured Long Term Debt				\$0
2272	Matured Interest on Long Term Debt				\$0
2285	Obligations Under Capital Leases--Current				\$0
2290	Commodity Taxes				\$0
2292	Payroll Deductions / Expenses Payable				\$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.				\$0
2296	Future Income Taxes - Current				\$0
2305	Accumulated Provision for Injuries and Damages				\$0
2306	Employee Future Benefits				\$0
2308	Other Pensions - Past Service Liability				\$0
2310	Vested Sick Leave Liability				\$0
2315	Accumulated Provision for Rate Refunds				\$0
2320	Other Miscellaneous Non-Current Liabilities				\$0
2325	Obligations Under Capital Lease--Non-Current				\$0
2330	Development Charge Fund				\$0
2335	Long Term Customer Deposits				\$0
2340	Collateral Funds Liability				\$0
2345	Unamortized Premium on Long Term Debt				\$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion				\$0
2350	Future Income Tax - Non-Current				\$0
2405	Other Regulatory Liabilities				\$0
2410	Deferred Gains from Disposition of Utility Plant				\$0
2415	Unamortized Gain on Reacquired Debt				\$0
2425	Other Deferred Credits				\$0
2435	Accrued Rate-Payer Benefit				\$0
2505	Debentures Outstanding - Long Term Portion				\$0
2510	Debenture Advances				\$0
2515	Reacquired Bonds				\$0
2520	Other Long Term Debt				\$0
2525	Term Bank Loans - Long Term Portion				\$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion				\$0
2550	Advances from Associated Companies				\$0
3005	Common Shares Issued				\$0

3008	Preference Shares Issued				\$0
3010	Contributed Surplus				\$0
3020	Donations Received				\$0
3022	Development Charges Transferred to Equity				\$0
3026	Capital Stock Held in Treasury				\$0
3030	Miscellaneous Paid-In Capital				\$0
3035	Installments Received on Capital Stock				\$0
3040	Appropriated Retained Earnings				\$0
3045	Unappropriated Retained Earnings				\$19,356
3046	Balance Transferred From Income	\$0	\$0		(\$2,530,275)
3047	Appropriations of Retained Earnings - Current Period				\$0
3048	Dividends Payable-Preference Shares				\$0
3049	Dividends Payable-Common Shares				\$0
3055	Adjustment to Retained Earnings				\$0
3065	Unappropriated Undistributed Subsidiary Earnings				\$0
4006	Residential Energy Sales				(\$10,846,188)
4010	Commercial Energy Sales				\$0
4015	Industrial Energy Sales				\$0
4020	Energy Sales to Large Users				\$0
4025	Street Lighting Energy Sales				(\$327,306)
4030	Sentinel Lighting Energy Sales				(\$26,033)
4035	General Energy Sales				(\$26,846,931)
4040	Other Energy Sales to Public Authorities				\$0
4045	Energy Sales to Railroads and Railways				\$0
4050	Revenue Adjustment				(\$5,341)
4055	Energy Sales for Resale				(\$10,643,209)
4060	Interdepartmental Energy Sales				\$0
4062	Billed WMS				(\$6,140,141)
4064	Billed-One-Time				\$0
4066	Billed NW				(\$4,714,512)
4068	Billed CN				(\$3,942,860)
4080	Distribution Services Revenue	\$3,145,963			(\$14,943,566)
4082	Retail Services Revenues				(\$1,680)
4084	Service Transaction Requests (STR) Revenues				(\$52,779)
4090	Electric Services Incidental to Energy Sales				\$0
4105	Transmission Charges Revenue				\$0
4110	Transmission Services Revenue				\$0
4205	Interdepartmental Rents				\$0
4210	Rent from Electric Property				(\$115,785)
4215	Other Utility Operating Income				(\$0)
4220	Other Electric Revenues				(\$0)
4225	Late Payment Charges				(\$140,729)
4230	Sales of Water and Water Power				\$0
4235	Miscellaneous Service Revenues	\$223,404			(\$439,085)
4240	Provision for Rate Refunds				\$0
4245	Government Assistance Directly Credited to Income				\$0
4305	Regulatory Debits				\$0
4310	Regulatory Credits				\$0
4315	Revenues from Electric Plant Leased to Others				\$0
4320	Expenses of Electric Plant Leased to Others				\$0
4325	Revenues from Merchandise, Jobbing, Etc.				\$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.				\$0
4335	Profits and Losses from Financial Instrument Hedges				\$0
4340	Profits and Losses from Financial Instrument Investments				\$0
4345	Gains from Disposition of Future Use Utility Plant				\$0
4350	Losses from Disposition of Future Use Utility Plant				\$0
4355	Gain on Disposition of Utility and Other Property				(\$58,694)
4360	Loss on Disposition of Utility and Other Property				\$0
4365	Gains from Disposition of Allowances for Emission				\$0
4370	Losses from Disposition of Allowances for Emission				\$0
4375	Revenues from Non-Utility Operations				\$0
4380	Expenses of Non-Utility Operations				\$0
4385	Non-Utility Rental Income				\$0
4390	Miscellaneous Non-Operating Income				(\$27,979)
4395	Rate-Payer Benefit Including Interest				\$0
4398	Foreign Exchange Gains and Losses, Including Amortization				\$0
4405	Interest and Dividend Income				(\$541,754)
4415	Equity in Earnings of Subsidiary Companies				\$0
4505	Operation Supervision and Engineering				\$0
4510	Fuel				\$0
4515	Steam Expense				\$0
4520	Steam From Other Sources				\$0
4525	Steam Transferred--Credit				\$0
4530	Electric Expense				\$0
4535	Water For Power				\$0
4540	Water Power Taxes				\$0
4545	Hydraulic Expenses				\$0
4550	Generation Expense				\$0
4555	Miscellaneous Power Generation Expenses				\$0
4560	Rents				\$0
4565	Allowances for Emissions				\$0
4605	Maintenance Supervision and Engineering				\$0
4610	Maintenance of Structures				\$0
4615	Maintenance of Boiler Plant				\$0
4620	Maintenance of Electric Plant				\$0
4625	Maintenance of Reservoirs, Dams and Waterways				\$0
4630	Maintenance of Water Wheels, Turbines and Generators				\$0
4635	Maintenance of Generating and Electric Plant				\$0

4640	Maintenance of Miscellaneous Power Generation Plant			\$0
4705	Power Purchased			\$48,873,044
4708	Charges-WMS			\$6,170,880
4710	Cost of Power Adjustments			(\$928,721)
4712	Charges-One-Time			\$0
4714	Charges-NW			\$5,151,962
4715	System Control and Load Dispatching			\$0
4716	Charges-CN			\$4,301,483
4720	Other Expenses			\$0
4725	Competition Transition Expense			\$0
4730	Rural Rate Assistance Expense			\$0
4805	Operation Supervision and Engineering			\$0
4810	Load Dispatching			\$0
4815	Station Buildings and Fixtures Expenses			\$0
4820	Transformer Station Equipment - Operating Labour			\$0
4825	Transformer Station Equipment - Operating Supplies and Expense			\$0
4830	Overhead Line Expenses			\$0
4835	Underground Line Expenses			\$0
4840	Transmission of Electricity by Others			\$0
4845	Miscellaneous Transmission Expense			\$0
4850	Rents			\$0
4905	Maintenance Supervision and Engineering			\$0
4910	Maintenance of Transformer Station Buildings and Fixtures			\$0
4916	Maintenance of Transformer Station Equipment			\$0
4930	Maintenance of Towers, Poles and Fixtures			\$0
4935	Maintenance of Overhead Conductors and Devices			\$0
4940	Maintenance of Overhead Lines - Right of Way			\$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs			\$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails			\$0
4960	Maintenance of Underground Lines			\$0
4965	Maintenance of Miscellaneous Transmission Plant			\$0
5005	Operation Supervision and Engineering			\$149,475
5010	Load Dispatching			\$8,647
5012	Station Buildings and Fixtures Expense			\$36,949
5014	Transformer Station Equipment - Operation Labour			\$2,684
5015	Transformer Station Equipment - Operation Supplies and Expenses			\$790
5016	Distribution Station Equipment - Operation Labour			\$0
5017	Distribution Station Equipment - Operation Supplies and Expenses			\$0
5020	Overhead Distribution Lines and Feeders - Operation Labour			\$618
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses			\$13,854
5030	Overhead Subtransmission Feeders - Operation			\$0
5035	Overhead Distribution Transformers- Operation	\$53,115		\$75,942
5040	Underground Distribution Lines and Feeders - Operation Labour			\$1,840
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses			\$8,828
5050	Underground Subtransmission Feeders - Operation			\$0
5055	Underground Distribution Transformers - Operation	\$1,316		\$1,881
5060	Street Lighting and Signal System Expense			\$0
5065	Meter Expense			\$187,306
5070	Customer Premises - Operation Labour			\$695
5075	Customer Premises - Materials and Expenses			\$0
5085	Miscellaneous Distribution Expense			\$145,851
5090	Underground Distribution Lines and Feeders - Rental Paid			\$0
5095	Overhead Distribution Lines and Feeders - Rental Paid			\$0
5096	Other Rent			\$0
5105	Maintenance Supervision and Engineering			\$382,063
5110	Maintenance of Buildings and Fixtures - Distribution Stations			\$1,003
5112	Maintenance of Transformer Station Equipment			\$0
5114	Maintenance of Distribution Station Equipment			\$13,660
5120	Maintenance of Poles, Towers and Fixtures			\$177,641
5125	Maintenance of Overhead Conductors and Devices			\$336,004
5130	Maintenance of Overhead Services			\$186,444
5135	Overhead Distribution Lines and Feeders - Right of Way			\$328,552
5145	Maintenance of Underground Conduit			\$94,368
5150	Maintenance of Underground Conductors and Devices			\$101,959
5155	Maintenance of Underground Services			\$223,190
5160	Maintenance of Line Transformers	\$460,762		\$658,786
5165	Maintenance of Street Lighting and Signal Systems			\$0
5170	Sentinel Lights - Labour			\$0
5172	Sentinel Lights - Materials and Expenses			\$0
5175	Maintenance of Meters			\$685
5178	Customer Installations Expenses- Leased Property			\$0
5185	Water Heater Rentals - Labour			\$0
5186	Water Heater Rentals - Materials and Expenses			\$0
5190	Water Heater Controls - Labour			\$0
5192	Water Heater Controls - Materials and Expenses			\$0

Financial Statement
(EDR Sheet 2.4, Reclassified Balance
Column P)

Grouped Accounts as per 2006 EDR

Land and Buildings	\$181,246	\$181,246
TS Primary Above 50	\$3,174,688	\$3,174,688
DS	\$140,683	\$140,683
Poles, Wires	\$31,725,526	\$31,725,526
Line Transformers	\$10,253,676	\$10,253,676
Services and Meters	\$4,922,182	\$4,922,182
General Plant	\$0	\$0
Equipment	\$1,574,064	\$1,574,064
IT Assets	\$0	\$0
CDM Expenditures and Recoveries	\$548,247	\$548,247
Other Distribution Assets	\$354,804	\$354,804
Contributions and Grants	\$0	\$0
Accumulated Amortization	(\$7,319,534)	(\$7,319,534)
Non-Distribution Asset	\$386,336	\$386,336
Unclassified Asset	(\$382,100)	(\$382,100)
Liability	\$0	\$0
Equity	\$19,356	(\$2,510,919)
Sales of Electricity	(\$63,492,520)	(\$63,492,520)
Distribution Services Revenue	(\$11,797,603)	(\$14,943,566)
Late Payment Charges	(\$140,729)	(\$140,729)
Specific Service Charges	(\$223,404)	(\$439,085)
Other Distribution Revenue	(\$170,245)	(\$170,245)
Other Revenue - Unclassified	\$0	\$0
Other Income & Deductions	(\$628,428)	(\$628,428)
Power Supply Expenses (Working Capital)	\$63,637,460	\$63,637,460
Other Power Supply Expenses	\$0	\$0
Operation (Working Capital)	\$580,929	\$635,360
Maintenance (Working Capital)	\$2,043,592	\$2,504,354
Billing and Collection (Working Capital)	\$786,849	\$786,849
Community Relations (Working Capital)	\$133,357	\$133,357
Community Relations - CDM (Working Capital)	\$313,392	\$0
Administrative and General Expenses (Working Capital)	\$3,326,707	\$3,222,171
Insurance Expense (Working Capital)	\$16,657	\$16,657
Bad Debt Expense (Working Capital)	\$118,968	\$118,968
Advertising Expenses	\$25,183	\$25,183
Charitable Contributions	\$5,803	\$5,803
Amortization of Assets	\$2,476,213	\$2,476,213
Other Amortization - Unclassified	\$0	\$0
Interest Expense - Unclassified	\$0	\$1,713,823
Income Tax Expense - Unclassified	\$0	\$1,676,871
Other Distribution Expenses	\$162,777	\$162,777
Non-Distribution Expenses	(\$37,456)	(\$37,456)
Unclassified Expenses	\$0	\$0
Total	\$42,716,675	\$40,312,715



2006 Cost Allocation Information Filing

Brantford Power Inc.

EB-2005-0342 EB-2007-0001

Tuesday, January 30, 2007

Sheet 15 Miscellaneous Data Worksheet - Second Ru

kMs of Roads in Service Area Where
Distribution Lines Exist

450

Deemed Equity Component
of Rate Base (%)

50%

1	2	3	6
Residential	GS <50	GS>50-Regular	Large Use >5MW

Instructions (Cont'd):

Step 3: Insert Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column W)

Step 4: Insert Smart Meter Adder Included in Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column T)

11.68 24.81 316.07 316.07

0.28 0.28 0.28 0.28

in

7	8	9	10	11
Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power

0.30	0.31	13.54	0	0
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0.28	0.28
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2006 Cost Allocation Information Filing

Brantford Power Inc.
EB-2005-0342 EB-2007-0001
Tuesday, January 30, 2007

Sheet 16 Customer Data Worksheet - Second Run

Total kWhs	936,687,506
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Total kW	1,412,465
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Total Approved Distribution Revenue (\$)	\$14,943,566
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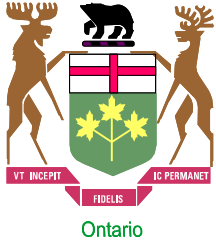
		1	2	3	7	8	9	
ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	
Billing Data								
kWh from approved EDR model, Sheet 7-1, Col M	CEN	936,687,506	280,782,062	103,857,225	419,188,349	6,417,655	549,561	2,646,052
kW from approved EDR model, Sheet 7-1, Col S	CDEM	1,412,465			1,112,825	18,932	1,690	
kWh, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		811,341			811,341			
Optional - 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	936,687,504	280,782,062	103,857,225	419,188,349	6,417,655	549,561	2,646,052
kWh - 30 year weather normalized amount		1,041,829,932	273,840,709	98,394,130	539,683,766	6,294,972	384,056	2,732,426
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	\$14,943,566	\$8,452,552	\$1,470,962	\$4,608,886	\$58,909	\$5,296	\$103,457
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	\$138,344	\$62,761	\$11,322	\$64,261	\$0	\$0	\$0
Late Payment 3 Year Historical Average	LPHA	\$189,500	\$116,416	\$23,082	\$50,002			
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	1.0
Number of Bills	CNB	428,977	385,296	29,532	4,692	12	3,144	6,276
Number of Connections (Unmetered)	CCON	1,753				461	769	523
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	45,017	32,108	2,461	391	8,762	769	523
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	34,963	32,108	2,461	391			
Line Transformer Customer Base	CCLT	34,870	32,108	2,459	303			
Secondary Customer Base	CCS	33,353	32,108	1,245	-			
Weighted - Services	CWCS	36,351	32,108	2,490	-	461	769	523
Weighted Meter -Capital	CWMC	3,339,380	1,848,880	433,770	1,052,130	-	-	-
Weighted Meter Reading	CWMR	525,420	423,672	64,344	36,228	-	-	-
Weighted Bills	CWNB	483,999	385,296	59,064	32,844	12	314	6,276
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		15,979,067	8,243,592	1,393,587	5,933,707	57,783	3,701	106,834

Weather Normalized Data from Hydro

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	1,080,481,823	284,000,199	102,044,553	559,706,033	6,528,516	398,304	2,833,799
2006 EDR Distribution Loss Factor		1.0371	1.0371	1.0371	1.0371	1.0371	1.0371

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	122,081	56,844	9,124	56,113			
Sheet ADJ5 rows 26 - 32, column F	173,982	66,362	16,079	91,541			
Sheet ADJ5 rows 26 - 32, column G	118,968	65,076	8,763	45,129			
Three-year average	138,344	62,761	11,322	64,261	-	-	-



2006 Cost Allocation Information Filing

Brantford Power Inc.

EB-2005-0342 EB-2007-0001

Tuesday, January 30, 2007

Sheet I7.1 Meter Capital Worksheet - Second R

	Residential	
	1	2
	Number of Meters	Weighted Metering Costs
Allocation Percentage Weighted Factor		
Cost Relative to Residential Average Cost		
Total	32108	1848880

Meter Types

Meter Types	Cost per Meter (Installed)		
Single Phase 200 Amp - Urban	50	27,716	1385800
Single Phase 200 Amp - Rural	150		0
Central Meter	250		0
Network Meter (Costs to be updated)	225	642	144450
Three-phase - No demand	210	3	630
Smart Meters	300		0
Demand without IT (usually three-phase)	500	636	318000
Demand with IT	2,100		0
Demand with IT and Interval Capability - Secondary	2,300		0
Demand with IT and Interval Capability - Primary	10,000		0
Demand with IT and Interval Capability -Special (WMP)	40,000		0
LDC Specific 1		3,111	0
LDC Specific 2			0
LDC Specific 3			0

un

GS <50				
3	1	2	3	1
Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters
55.37%			13%	
1.00			3.10	
57.58315685	2432	433770	178.359375	420

	1,206	60300		
		0		
	19	4750		
	128	28800		
	452	94920		23
		0		
	490	245000		
		0		318
		0		65
		0		11
		0		3
	137	0		
		0		
		0		

GS>50-Regular		Large Use >5MW		
2	3	1	2	3
Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	32%			0%
	43.50			39.94
1052130	2505.071429	1	2300	2300

0			0	
0			0	
0			0	
0			0	
4830			0	
0			0	
0			0	
667800			0	
149500		1	2300	
110000			0	
120000			0	
0			0	
0			0	
0			0	

Embedded Distributor		Back-up/Standby Power		
2	3	1	2	3
Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	0%			0%
	-			39.94
0	-	1	2300	2300

0			0	
0			0	
0			0	
0			0	
0			0	
0			0	
0			0	
0			0	
0		1	2300	
0			0	
0			0	
0			0	
0			0	
0			0	

TOTAL		
1	2	3
Number of Meters	Weighted Metering Costs	Weighted Average Costs
		100%
		1.66
34962	3339380	95.51455866
28,922	1446100	
0	0	
19	4750	
770	173250	
478	100380	
0	0	
1,126	563000	
318	667800	
67	154100	
11	110000	
3	120000	
3,248	0	
0	0	
0	0	



2006 Cost Allocation Information Filing

Brantford Power Inc.

EB-2005-0342 EB-2007-0001

Tuesday, January 30, 2007

Sheet I7.2 Meter Reading Worksheet - Second Run

Weighting Factors based on
Contractor Pricing

Description		1			2			3		
		Residential			GS <50			GS>50-Regular		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage	80.63%			12.25%			6.90%		
	Weighted Factor	1.00			1.97			7.06		
	Cost Relative to Residential Average Cost	1.00			1.97			7.06		
	Total	385,152	423,672	1.10	29,652	64,344	2.17	4,668	36,228	7.76
	Factor									
Residential - Urban - Outside	1.00	346,632	346,632		0			0		
Residential - Urban - Outside with other services	1.00		0		0			0		
Residential - Urban - Inside	2.00	38,520	77,040		0			0		
Residential - Urban - Inside - with other services	1.00		0		0			0		
Residential - Rural - Outside	3.00		0		0			0		
Residential - Rural - Outside with other services	2.00		0		0			0		
LDC Specific 1			0		0			0		
LDC Specific 2			0		0			0		
GS - Walking	2.00		0		24,612	49,224		2,064	4,128	
GS - Walking - with other services	3.00		0			0			0	
GS - Vehicle with other services -- TOU Read	3.00		0			0			0	
GS - Vehicle with other services	3.00		0		5,040	15,120		2,076	6,228	
LDC Specific 3			0			0			0	
LDC Specific 4	0.00		0			0			0	
Interval	49.00		0			0		528	25,872	
LDC Specific 5			0			0			0	
LDC Specific 6			0			0			0	

10			11			TOTAL		
Embedded Distributor			Back-up/Standby Power			TOTAL		
Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	0.00%			0.11%				100.00%
	0.00			44.54				99.12
-	-	0	12	588	49.00	419,496	525,420	109
0			0			346,632	346,632	
0			0			-	-	
0			0			38,520	77,040	
0			0			-	-	
0			0			-	-	
0			0			-	-	
0			0			-	-	
0			0			-	-	
0			0			26,676	53,352	
0			0			-	-	
0			0			-	-	
0			0			7,116	21,348	
0			0			-	-	
0			0			-	-	
0			12	588		552	27,048	
0			0			-	-	
0			0			-	-	

	A	B	C	D	E	F	J	K	L	X
1	2006 Cost Allocation Information Filing									
2	Brantford Power Inc.									
3	EB-2005-0342 EB-2007-0001									
4	Tuesday, January 30, 2007									
5	Sheet 18 Demand Data Worksheet - Second Run									
7	This is an input sheet for demand allocators.									
14	CP TEST RESULTS					12 CP				
15	NCP TEST RESULTS					4 NCP				
17	Co-incident Peak					Indicator				
18	1 CP					CP 1				
19	4 CP					CP 4				
20	12 CP					CP 12				
24	Non-co-incident Peak					Indicator				
25	1 NCP					NCP 1				
26	4 NCP					NCP 4				
27	12 NCP					NCP 12				
30				1	2	3	7	8	9	
31	Customer Classes	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load		
35	CO-INCIDENT PEAK									
37	1 CP									
38	Transformation CP	TCP1	194,191	61,604	20,840	91,315	-	-	281	
39	Bulk Delivery CP	BCP1	194,191	61,604	20,840	91,315	-	-	281	
40	Total Sytem CP	DCP1	194,191	61,604	20,840	91,315	-	-	281	
42	4 CP									
43	Transformation CP	TCP4	722,596	229,791	70,810	343,101	272	15	1,114	
44	Bulk Delivery CP	BCP4	722,596	229,791	70,810	343,101	272	15	1,114	
45	Total Sytem CP	DCP4	722,596	229,791	70,810	343,101	272	15	1,114	
47	12 CP									
48	Transformation CP	TCP12	1,978,466	586,685	199,164	962,191	5,812	287	3,490	
49	Bulk Delivery CP	BCP12	1,978,466	586,685	199,164	962,191	5,812	287	3,490	
50	Total Sytem CP	DCP12	1,978,466	586,685	199,164	962,191	5,812	287	3,490	
52	NON CO INCIDENT PEAK									
54	1 NCP									
55	Classification NCP from									
55	Load Data Provider	DNCP1	216,278	67,703	23,728	97,082	1,853	160	487	
56	Primary NCP	PNCP1	216,278	67,703	23,728	97,082	1,853	160	487	
57	Line Transformer NCP	LTNCP1	123,750	67,703	23,685	29,861	1,853	160	487	
58	Secondary NCP	SNCP1	80,666	67,703	10,462	-	1,853	160	487	
60	4 NCP									
61	Classification NCP from									
61	Load Data Provider	DNCP4	817,305	253,327	89,894	366,789	7,358	553	1,850	
62	Primary NCP	PNCP4	817,305	253,327	89,894	366,789	7,358	553	1,850	
63	Line Transformer NCP	LTNCP4	465,638	253,327	89,729	112,821	7,358	553	1,850	
64	Secondary NCP	SNCP4	302,722	253,327	39,634	-	7,358	553	1,850	
66	12 NCP									
67	Classification NCP from									
67	Load Data Provider	DNCP12	2,214,085	661,118	229,386	1,036,754	20,594	1,311	4,834	
68	Primary NCP	PNCP12	2,214,085	661,118	229,386	1,036,754	20,594	1,311	4,834	
69	Line Transformer NCP	LTNCP12	1,235,719	661,118	228,966	318,895	20,594	1,311	4,834	
70	Secondary NCP	SNCP12	788,993	661,118	101,135	-	20,594	1,311	4,834	



Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base		Total	1	2	3	6	7	8	9	10	11
Assets		Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	
crev	Distribution Revenue (sale)	\$14,943,566	\$8,452,552	\$1,470,962	\$4,608,886	\$186,882	\$58,909	\$5,296	\$103,457	\$399	\$56,222
mi	Miscellaneous Revenue (mi)	\$1,378,487	\$925,678	\$165,621	\$233,757	\$8,567	\$9,518	\$4,746	\$10,546	\$17,290	\$2,764
	Total Revenue	\$16,322,053	\$9,378,230	\$1,636,583	\$4,842,643	\$195,450	\$68,427	\$10,042	\$114,003	\$17,689	\$58,986
	Expenses										
di	Distribution Costs (di)	\$2,951,028	\$1,890,892	\$343,676	\$533,505	\$27,104	\$41,150	\$26,341	\$21,902	\$56,288	\$10,170
cu	Customer Related Costs (cu)	\$1,094,503	\$786,301	\$130,276	\$168,026	\$513	\$25	\$446	\$8,631	\$1	\$283
ad	General and Administration (ad)	\$3,565,948	\$2,347,724	\$418,045	\$627,297	\$25,209	\$36,800	\$23,480	\$26,528	\$51,434	\$9,430
dep	Depreciation and Amortization (dep)	\$2,476,213	\$1,486,517	\$293,682	\$541,218	\$27,830	\$31,686	\$14,809	\$13,877	\$57,400	\$9,194
INPUT	PILs (INPUT)	\$1,676,871	\$1,005,673	\$198,848	\$367,572	\$18,890	\$21,419	\$9,971	\$9,343	\$38,956	\$6,200
INT	Interest	\$1,713,823	\$1,027,834	\$203,230	\$375,672	\$19,306	\$21,891	\$10,191	\$9,549	\$39,815	\$6,336
	Total Expenses	\$13,478,386	\$8,544,942	\$1,587,756	\$2,613,290	\$118,853	\$152,970	\$85,238	\$89,830	\$243,894	\$41,612
	Direct Allocation	\$313,392	\$218,391	\$90,723	\$4,278	\$0	\$0	\$0	\$0	\$0	\$0
NI	Allocated Net Income (NI)	\$2,530,275	\$1,517,486	\$300,047	\$554,639	\$28,504	\$32,319	\$15,045	\$14,098	\$58,782	\$9,355
	Revenue Requirement (includes NI)	\$16,322,053	\$10,280,819	\$1,978,526	\$3,172,207	\$147,356	\$185,289	\$100,283	\$103,928	\$302,676	\$50,967
	Revenue Requirement Input equals Output										
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	\$50,946,247	\$30,701,792	\$6,050,862	\$11,036,285	\$561,587	\$655,947	\$305,912	\$285,656	\$1,158,158	\$190,046
gp	General Plant - Gross	\$1,928,869	\$1,156,804	\$228,731	\$422,810	\$21,729	\$24,637	\$11,469	\$10,747	\$44,810	\$7,131
accum dep	Accumulated Depreciation	(\$7,319,534)	(\$4,537,464)	(\$877,486)	(\$1,473,267)	(\$70,130)	(\$98,703)	(\$46,501)	(\$42,583)	(\$144,646)	(\$28,755)
co	Capital Contribution	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Total Net Plant	\$45,555,582	\$27,321,133	\$5,402,107	\$9,985,829	\$513,186	\$581,882	\$270,881	\$253,820	\$1,058,322	\$168,423
	Directly Allocated Net Fixed Assets	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
COP	Cost of Power (COP)	\$63,637,460	\$19,096,649	\$7,056,469	\$28,463,458	\$3,131,806	\$436,415	\$37,705	\$179,959	\$5,183,777	\$51,222
	OM&A Expenses	\$7,611,479	\$5,024,917	\$891,997	\$1,328,829	\$52,827	\$77,974	\$50,267	\$57,062	\$107,724	\$19,882
	Directly Allocated Expenses	\$313,392	\$218,391	\$90,723	\$4,278	\$0	\$0	\$0	\$0	\$0	\$0
	Subtotal	\$71,562,331	\$24,339,957	\$8,039,189	\$29,796,565	\$3,184,633	\$514,390	\$87,972	\$237,021	\$5,291,500	\$71,105
	Working Capital	\$10,734,350	\$3,650,994	\$1,205,878	\$4,469,485	\$477,695	\$77,158	\$13,196	\$35,553	\$793,725	\$10,666
	Total Rate Base	\$56,289,932	\$30,972,126	\$6,607,985	\$14,455,313	\$990,881	\$659,040	\$284,077	\$289,373	\$1,852,047	\$179,088
	Rate Base Input equals Output										
	Equity Component of Rate Base	\$28,144,966	\$15,486,063	\$3,303,993	\$7,227,657	\$495,440	\$329,520	\$142,039	\$144,687	\$926,024	\$89,544
	Net Income on Allocated Assets	\$2,530,275	\$614,897	(\$41,896)	\$2,225,075	\$76,597	(\$84,543)	(\$75,196)	\$24,173	(\$226,205)	\$17,373
	Net Income on Direct Allocation Assets	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Net Income	\$2,530,275	\$614,897	(\$41,896)	\$2,225,075	\$76,597	(\$84,543)	(\$75,196)	\$24,173	(\$226,205)	\$17,373
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES %	100.00%	91.22%	82.72%	152.66%	132.64%	36.93%	10.01%	109.69%	5.84%	115.73%
	EXISTING REVENUE MINUS ALLOCATED COSTS	(\$0)	(\$902,590)	(\$341,943)	\$1,670,436	\$48,093	(\$116,862)	(\$90,241)	\$10,075	(\$284,987)	\$8,019
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.99%	3.97%	-1.27%	30.79%	15.46%	-25.66%	-52.94%	16.71%	-24.43%	19.40%



2006 Cost Allocation Information Filing

Brantford Power Inc.
EB-2005-0342 EB-2007-0001
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Sheet 02 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	6	7	8	9	10	11
	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
Customer Unit Cost per month - Avoided Cost	\$2.50	\$6.03	\$63.47	\$78.42	\$0.00	\$0.03	\$0.84	\$0.35	\$66.75
Customer Unit Cost per month - Directly Related	\$3.87	\$9.10	\$85.28	\$114.80	\$0.01	\$0.06	\$1.67	\$0.43	\$90.34
Customer Unit Cost per month - Minimum System with PLCC Adjustment	\$12.52	\$16.99	\$116.13	\$183.33	\$8.62	\$10.86	\$9.72	\$138.94	\$118.72
Fixed Charge per approved 2006 EDR	\$11.68	\$24.81	\$316.07	\$316.07	\$0.30	\$0.31	\$13.54	\$0.00	\$0.00

Information to be Used to Allocate PILs, ROD, ROE and A&G

	1	2	3	6	7	8	9	10	11	
Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	
General Plant - Gross Assets	\$1,928,869	\$1,156,804	\$228,731	\$422,810	\$21,729	\$24,637	\$11,469	\$10,747	\$44,810	\$7,131
General Plant - Accumulated Depreciation	(\$892,075)	(\$535,005)	(\$105,785)	(\$195,544)	(\$10,049)	(\$11,394)	(\$5,304)	(\$4,970)	(\$20,724)	(\$3,298)
General Plant - Net Fixed Assets	\$1,036,794	\$621,799	\$122,946	\$227,266	\$11,680	\$13,243	\$6,165	\$5,777	\$24,086	\$3,833
General Plant - Depreciation	\$262,389	\$157,363	\$31,115	\$57,516	\$2,956	\$3,351	\$1,560	\$1,462	\$6,096	\$970
Total Net Fixed Assets Excluding General Plant	\$44,518,788	\$26,699,334	\$5,279,161	\$9,758,562	\$501,506	\$568,639	\$264,716	\$248,043	\$1,034,236	\$164,590
Total Administration and General Expense	\$3,634,761	\$2,388,994	\$426,205	\$642,381	\$25,984	\$37,679	\$23,889	\$26,912	\$53,032	\$9,685
Total O&M	\$4,045,531	\$2,677,193	\$473,952	\$701,532	\$27,618	\$41,175	\$26,787	\$30,533	\$56,290	\$10,452

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor	11 Back-up/Standby Power
1860	<u>Distribution Plant</u> Meters										
	<u>Accumulated Amortization</u> Accum. Amortization of Electric Utility Plant - Meters only										
	<u>Meter Net Fixed Assets</u>										
	<u>Misc Revenue</u>										
4082	Retail Services Revenues										
4084	Service Transaction Requests (STR) Revenues										
4090	Electric Services Incidental to Energy Sales										
4220	Other Electric Revenues										
4225	Late Payment Charges										

Sub-total

5065 **Operation**
 Meter Expense
 5070 Customer Premises - Operation Labour
 5075 Customer Premises - Materials and Expenses

Sub-total

5175 **Maintenance**
 Maintenance of Meters

5310 **Billing and Collection**
 Meter Reading Expense
 5315 Customer Billing
 5320 Collecting
 5325 Collecting- Cash Over and Short
 5330 Collection Charges

Sub-total

Total Operation, Maintenance and Billing

Amortization Expense - Meters
Allocated PILs
Allocated Debt Return
Allocated Equity Return

Total

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts										
----------------	----------	--	--	--	--	--	--	--	--	--	--

1860 **Distribution Plant**
 Meters

Accumulated Amortization
 Accum. Amortization of Electric Utility Plant - Meters only
Meter Net Fixed Assets
Allocated General Plant Net Fixed Assets
Meter Net Fixed Assets Including General Plant

4082 **Misc Revenue**
 Retail Services Revenues
 4084 Service Transaction Requests (STR) Revenues
 4090 Electric Services Incidental to Energy Sales
 4220 Other Electric Revenues
 4225 Late Payment Charges

Sub-total

5065 **Operation**
 Meter Expense
 5070 Customer Premises - Operation Labour
 5075 Customer Premises - Materials and Expenses

Sub-total

5175 **Maintenance**
 Maintenance of Meters

5310 **Billing and Collection**
 Meter Reading Expense
 5315 Customer Billing
 5320 Collecting
 5325 Collecting- Cash Over and Short
 5330 Collection Charges

Sub-total

Total Operation, Maintenance and Billing

Amortization Expense - Meters
Amortization Expense -
General Plant assigned to Meters
Admin and General
Allocated PILs
Allocated Debt Return
Allocated Equity Return

Total

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts										
	Distribution Plant										
1565	Conservation and Demand Management										
	Expenditures and Recoveries										
1830	Poles, Towers and Fixtures										
	Poles, Towers and Fixtures - Subtransmission Bulk										
1830-3	Delivery										
1830-4	Poles, Towers and Fixtures - Primary										
1830-5	Poles, Towers and Fixtures - Secondary										
1835	Overhead Conductors and Devices										
	Overhead Conductors and Devices -										
1835-3	Subtransmission Bulk Delivery										
1835-4	Overhead Conductors and Devices - Primary										
1835-5	Overhead Conductors and Devices - Secondary										
1840	Underground Conduit										
1840-3	Underground Conduit - Bulk Delivery										
1840-4	Underground Conduit - Primary										
1840-5	Underground Conduit - Secondary										
1845	Underground Conductors and Devices										
1845-3	Underground Conductors and Devices - Bulk Delivery										
1845-4	Underground Conductors and Devices - Primary										
1845-5	Underground Conductors and Devices - Secondary										
1850	Line Transformers										
1855	Services										
1860	Meters										

Sub-total

Accumulated Amortization
Accum. Amortization of Electric Utility Plant -Line
Transformers, Services and Meters
Customer Related Net Fixed Assets
Allocated General Plant Net Fixed Assets
Customer Related NFA Including General Plant

Misc Revenue

4082 Retail Services Revenues
4084 Service Transaction Requests (STR) Revenues
4090 Electric Services Incidental to Energy Sales
4220 Other Electric Revenues
4225 Late Payment Charges
4235 Miscellaneous Service Revenues

Sub-total

	<u>Operating and Maintenance</u>
5005	Operation Supervision and Engineering
5010	Load Dispatching
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5055	Underground Distribution Transformers - Operation
5065	Meter Expense
5070	Customer Premises - Operation Labour
5075	Customer Premises - Materials and Expenses
5085	Miscellaneous Distribution Expense
5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5096	Other Rent
5105	Maintenance Supervision and Engineering
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5130	Maintenance of Overhead Services
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5155	Maintenance of Underground Services
5160	Maintenance of Line Transformers
5175	Maintenance of Meters

Sub-total

	<u>Billing and Collection</u>
5305	Supervision
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting- Cash Over and Short
5330	Collection Charges
5335	Bad Debt Expense
5340	Miscellaneous Customer Accounts Expenses

Sub-total

Sub Total Operating, Maintenance and Billing

Amortization Expense - Customer Related
Amortization Expense - General Plant assigned to Meters
Admin and General
Allocated PILs
Allocated Debt Return
Allocated Equity Return

PLCC Adjustment for Line Transformer
PLCC Adjustment for Primary Costs
PLCC Adjustment for Secondary Costs

Total

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
Distribution Plant										
CWMC	\$ 4,922,182	\$ 2,725,213	\$ 639,369	\$ 1,550,819	\$ 3,390	\$ -	\$ -	\$ -	\$ -	\$ 3,390
Accumulated Amortization										
Accum. Amortization of Electric Utility Plant - Meters only	\$ (669,665)	\$ (370,766)	\$ (86,986)	\$ (210,990)	\$ (461)	\$ -	\$ -	\$ -	\$ -	\$ (461)
Meter Net Fixed Assets	\$ 4,252,517	\$ 2,354,447	\$ 552,382	\$ 1,339,830	\$ 2,929	\$ -	\$ -	\$ -	\$ -	\$ 2,929
Misc Revenue										
CWNB	\$ (54,459)	\$ (43,353)	\$ (6,646)	\$ (3,696)	\$ (20)	\$ (1)	\$ (35)	\$ (706)	\$ (0)	\$ (1)
NFA	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)
LPHA	\$ (140,729)	\$ (86,454)	\$ (17,141)	\$ (37,133)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Sub-total	\$ (195,189)	\$ (129,808)	\$ (23,787)	\$ (40,829)	\$ (20)	\$ (1)	\$ (35)	\$ (706)	\$ (0)	\$ (1)
Operation										
CWMC	\$ 187,306	\$ 103,704	\$ 24,330	\$ 59,014	\$ 129	\$ -	\$ -	\$ -	\$ -	\$ 129
CCA	\$ 695	\$ 608	\$ 47	\$ 7	\$ 0	\$ 9	\$ 15	\$ 10	\$ 0	\$ 0
Sub-total	\$ 188,001	\$ 104,311	\$ 24,377	\$ 59,021	\$ 129	\$ 9	\$ 15	\$ 10	\$ 0	\$ 129
Maintenance										
1860	\$ 685	\$ 379	\$ 89	\$ 216	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ 0
Billing and Collection										
CWMB	\$ 122,000	\$ 98,375	\$ 14,940	\$ 8,412	\$ 137	\$ -	\$ -	\$ -	\$ -	\$ 137
CWNB	\$ 457,877	\$ 364,501	\$ 55,876	\$ 31,071	\$ 170	\$ 11	\$ 297	\$ 5,937	\$ 1	\$ 11
Sub-total	\$ 579,877	\$ 462,876	\$ 70,817	\$ 39,483	\$ 307	\$ 11	\$ 297	\$ 5,937	\$ 1	\$ 148
Total Operation, Maintenance and Billing	\$ 768,563	\$ 567,567	\$ 95,282	\$ 98,721	\$ 436	\$ 20	\$ 312	\$ 5,947	\$ 1	\$ 277
Amortization Expense - Meters	\$ 204,550	\$ 113,251	\$ 26,570	\$ 64,447	\$ 141	\$ -	\$ -	\$ -	\$ -	\$ 141
Allocated PILs	\$ 156,532	\$ 86,666	\$ 20,333	\$ 49,318	\$ 108	\$ -	\$ -	\$ -	\$ -	\$ 108
Allocated Debt Return	\$ 159,982	\$ 88,575	\$ 20,781	\$ 50,405	\$ 110	\$ -	\$ -	\$ -	\$ -	\$ 110
Allocated Equity Return	\$ 236,196	\$ 130,772	\$ 30,681	\$ 74,418	\$ 163	\$ -	\$ -	\$ -	\$ -	\$ 163
Total	\$ 1,330,634	\$ 857,023	\$ 169,860	\$ 296,480	\$ 938	\$ 19	\$ 277	\$ 5,241	\$ 1	\$ 798

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
Distribution Plant										
CWMC	\$ 4,922,182	\$ 2,725,213	\$ 639,369	\$ 1,550,819	\$ 3,390	\$ -	\$ -	\$ -	\$ -	\$ 3,390
Accumulated Amortization										
Accum. Amortization of Electric Utility Plant - Meters only	\$ (669,665)	\$ (370,766)	\$ (86,986)	\$ (210,990)	\$ (461)	\$ -	\$ -	\$ -	\$ -	\$ (461)
Meter Net Fixed Assets	\$ 4,252,517	\$ 2,354,447	\$ 552,382	\$ 1,339,830	\$ 2,929	\$ -	\$ -	\$ -	\$ -	\$ 2,929
Allocated General Plant Net Fixed Assets	\$ 99,037	\$ 54,833	\$ 12,864	\$ 31,203	\$ 68	\$ -	\$ -	\$ -	\$ -	\$ 68
Meter Net Fixed Assets Including General Plant	\$ 4,351,553	\$ 2,409,279	\$ 565,247	\$ 1,371,033	\$ 2,997	\$ -	\$ -	\$ -	\$ -	\$ 2,997
Misc Revenue										
CWNB	\$ (54,459)	\$ (43,353)	\$ (6,646)	\$ (3,696)	\$ (20)	\$ (1)	\$ (35)	\$ (706)	\$ (0)	\$ (1)
NFA	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)	\$ (0)
LPHA	\$ (140,729)	\$ (86,454)	\$ (17,141)	\$ (37,133)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Sub-total	\$ (195,189)	\$ (129,808)	\$ (23,787)	\$ (40,829)	\$ (20)	\$ (1)	\$ (35)	\$ (706)	\$ (0)	\$ (1)

Operation																						
CWMC	\$	187,306	\$	103,704	\$	24,330	\$	59,014	\$	129	\$	-	\$	-	\$	-	\$	-	\$	-	\$	129
CCA	\$	695	\$	608	\$	47	\$	7	\$	0	\$	9	\$	15	\$	10	\$	0	\$	0	\$	0
Sub-total	\$	188,001	\$	104,311	\$	24,377	\$	59,021	\$	129	\$	9	\$	15	\$	10	\$	0	\$	0	\$	129
Maintenance																						
1860	\$	685	\$	379	\$	89	\$	216	\$	0	\$	-	\$	-	\$	-	\$	-	\$	-	\$	0
Billing and Collection																						
CWMR	\$	122,000	\$	98,375	\$	14,940	\$	8,412	\$	137	\$	-	\$	-	\$	-	\$	-	\$	-	\$	137
CWNB	\$	457,877	\$	364,501	\$	55,876	\$	31,071	\$	170	\$	11	\$	297	\$	5,937	\$	1	\$	11	\$	11
Sub-total	\$	579,877	\$	462,876	\$	70,817	\$	39,483	\$	307	\$	11	\$	297	\$	5,937	\$	1	\$	148	\$	148
Total Operation, Maintenance and Billing	\$	768,563	\$	567,567	\$	95,282	\$	98,721	\$	436	\$	20	\$	312	\$	5,947	\$	1	\$	277	\$	277
Amortization Expense - Meters	\$	204,550	\$	113,251	\$	26,570	\$	64,447	\$	141	\$	-	\$	-	\$	-	\$	-	\$	-	\$	141
Amortization Expense -																						
General Plant assigned to Meters																						
Admin and General	\$	25,064	\$	13,877	\$	3,256	\$	7,897	\$	17	\$	-	\$	-	\$	-	\$	-	\$	-	\$	17
Allocated PILs	\$	688,755	\$	506,468	\$	85,683	\$	90,397	\$	411	\$	18	\$	278	\$	5,242	\$	1	\$	257	\$	257
Allocated Debt Return	\$	160,178	\$	88,684	\$	20,806	\$	50,467	\$	110	\$	-	\$	-	\$	-	\$	-	\$	-	\$	110
Allocated Equity Return	\$	163,708	\$	90,638	\$	21,265	\$	51,579	\$	113	\$	-	\$	-	\$	-	\$	-	\$	-	\$	113
Allocated Equity Return	\$	241,697	\$	133,818	\$	31,395	\$	76,151	\$	166	\$	-	\$	-	\$	-	\$	-	\$	-	\$	166
Total	\$	2,057,326	\$	1,384,495	\$	260,471	\$	398,829	\$	1,374	\$	37	\$	555	\$	10,483	\$	2	\$	1,081	\$	1,081

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power											
Distribution Plant																						
CDMPP	\$	548,247	\$	362,811	\$	64,230	\$	95,071	\$	3,743	\$	5,580	\$	3,630	\$	4,138	\$	7,628	\$	1,416	\$	1,416
Poles, Towers and Fixtures	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
BCP	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
PNCP	\$	6,275,344	\$	5,487,740	\$	420,622	\$	66,828	\$	171	\$	78,819	\$	131,434	\$	89,389	\$	171	\$	171	\$	171
SNCP	\$	4,828,590	\$	4,416,216	\$	171,240	\$	-	\$	-	\$	63,429	\$	105,770	\$	71,935	\$	-	\$	-	\$	-
Overhead Conductors and Devices	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
LTNCP	\$	3,076,103	\$	2,696,859	\$	206,540	\$	25,450	\$	-	\$	38,734	\$	64,591	\$	43,929	\$	-	\$	-	\$	-
CWCS	\$	0	\$	0	\$	0	\$	-	\$	-	\$	0	\$	0	\$	0	\$	-	\$	-	\$	-
CWMC	\$	4,922,182	\$	2,725,213	\$	639,369	\$	1,550,819	\$	3,390	\$	-	\$	-	\$	-	\$	-	\$	-	\$	3,390
Sub-total	\$	19,650,466	\$	15,688,840	\$	1,502,000	\$	1,738,168	\$	7,304	\$	186,562	\$	305,425	\$	209,390	\$	7,799	\$	4,978	\$	4,978
Accumulated Amortization																						
Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	\$	(2,605,445)	\$	(2,090,767)	\$	(196,134)	\$	(223,636)	\$	(485)	\$	(24,704)	\$	(41,195)	\$	(28,017)	\$	(23)	\$	(485)	\$	(485)
Customer Related Net Fixed Assets	\$	17,045,021	\$	13,598,073	\$	1,305,867	\$	1,514,532	\$	6,819	\$	161,858	\$	264,230	\$	181,373	\$	7,776	\$	4,493	\$	4,493
Allocated General Plant Net Fixed Assets	\$	396,960	\$	316,684	\$	30,412	\$	35,272	\$	159	\$	3,769	\$	6,154	\$	4,224	\$	181	\$	105	\$	105
Customer Related NFA Including General Plant	\$	17,441,981	\$	13,914,758	\$	1,336,279	\$	1,549,804	\$	6,978	\$	165,627	\$	270,384	\$	185,597	\$	7,957	\$	4,598	\$	4,598
Misc Revenue																						
CWNB	\$	(493,544)	\$	(392,894)	\$	(60,229)	\$	(33,492)	\$	(184)	\$	(12)	\$	(321)	\$	(6,400)	\$	(1)	\$	(12)	\$	(12)
NFA	\$	(0)	\$	(0)	\$	(0)	\$	(0)	\$	(0)	\$	(0)	\$	(0)	\$	(0)	\$	(0)	\$	(0)	\$	(0)
LPHA	\$	(140,729)	\$	(86,454)	\$	(17,141)	\$	(37,133)	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Sub-total	\$	(634,274)	\$	(479,349)	\$	(77,370)	\$	(70,625)	\$	(184)	\$	(12)	\$	(321)	\$	(6,400)	\$	(1)	\$	(12)	\$	(12)
Operating and Maintenance																						
1815-1855	\$	240,113	\$	213,372	\$	13,519	\$	1,563	\$	3	\$	3,065	\$	5,110	\$	3,476	\$	3	\$	3	\$	3
1830 & 1835	\$	120,058	\$	106,084	\$	7,186	\$	988	\$	3	\$	1,524	\$	2,541	\$	1,728	\$	3	\$	3	\$	3
1850	\$	220,983	\$	193,738	\$	14,838	\$	1,828	\$	0	\$	2,783	\$	4,640	\$	3,156	\$	-	\$	-	\$	-
1840 & 1845	\$	3,734	\$	3,363	\$	173	\$	14	\$	0	\$	48	\$	81	\$	55	\$	0	\$	0	\$	0
CWMC	\$	187,306	\$	103,704	\$	24,330	\$	59,014	\$	129	\$	-	\$	-	\$	-	\$	-	\$	-	\$	129
CCA	\$	695	\$	608	\$	47	\$	7	\$	0	\$	9	\$	15	\$	10	\$	0	\$	0	\$	0
O&M	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
1830	\$	62,174	\$	54,820	\$	3,814	\$	543	\$	1	\$	787	\$	1,313	\$	893	\$	1	\$	1	\$	1
1835	\$	117,601	\$	104,209	\$	6,806	\$	889	\$	2	\$	1,497	\$	2,496	\$	1,697	\$	2	\$	2	\$	2
1855	\$	409,634	\$	361,819	\$	28,059	\$	-	\$	-	\$	5,197	\$	8,666	\$	5,894	\$	-	\$	-	\$	-

1840	\$	33,029	\$	29,956	\$	1,369	\$	67	\$	0	\$	430	\$	717	\$	488	\$	0	\$	0
1845	\$	35,686	\$	31,908	\$	1,840	\$	194	\$	0	\$	458	\$	764	\$	520	\$	0	\$	0
1860	\$	685	\$	379	\$	89	\$	216	\$	0	\$	-	\$	-	\$	-	\$	-	\$	0
Sub-total	\$	1,431,697	\$	1,203,960	\$	102,071	\$	65,323	\$	139	\$	15,797	\$	26,343	\$	17,916	\$	10	\$	139
Billing and Collection																				
CWNB	\$	664,849	\$	529,264	\$	81,134	\$	45,116	\$	247	\$	16	\$	432	\$	8,621	\$	1	\$	16
CWMR	\$	122,000	\$	98,375	\$	14,940	\$	8,412	\$	137	\$	-	\$	-	\$	-	\$	-	\$	137
BDHA	\$	118,968	\$	53,971	\$	9,736	\$	55,261	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Sub-total	\$	905,817	\$	681,610	\$	105,810	\$	108,789	\$	384	\$	16	\$	432	\$	8,621	\$	1	\$	153
Sub Total Operating, Maintenance and Billing	\$	2,337,514	\$	1,885,570	\$	207,881	\$	174,112	\$	523	\$	15,814	\$	26,774	\$	26,537	\$	11	\$	292
Amortization Expense - Customer Related	\$	853,863	\$	681,024	\$	65,637	\$	75,431	\$	424	\$	8,182	\$	13,226	\$	9,118	\$	569	\$	253
Amortization Expense - General Plant assigned to Meters	\$	100,462	\$	80,146	\$	7,697	\$	8,926	\$	40	\$	954	\$	1,557	\$	1,069	\$	46	\$	26
Admin and General	\$	2,091,471	\$	1,682,589	\$	186,939	\$	159,431	\$	492	\$	14,471	\$	23,878	\$	23,389	\$	11	\$	271
Allocated PILs	\$	642,028	\$	512,193	\$	49,188	\$	57,047	\$	257	\$	6,097	\$	9,953	\$	6,832	\$	293	\$	169
Allocated Debt Return	\$	656,176	\$	523,480	\$	50,271	\$	58,304	\$	263	\$	6,231	\$	10,172	\$	6,982	\$	299	\$	173
Allocated Equity Return	\$	968,773	\$	772,862	\$	74,220	\$	86,080	\$	388	\$	9,199	\$	15,018	\$	10,309	\$	442	\$	255
PLCC Adjustment for Line Transformer	\$	316,400	\$	283,289	\$	21,730	\$	2,688	\$	-	\$	4,090	\$	-	\$	4,603	\$	-	\$	-
PLCC Adjustment for Primary Costs	\$	206,129	\$	183,602	\$	14,433	\$	2,444	\$	6	\$	2,645	\$	-	\$	2,987	\$	6	\$	6
PLCC Adjustment for Secondary Costs	\$	525,723	\$	475,221	\$	34,733	\$	-	\$	-	\$	6,505	\$	-	\$	9,264	\$	-	\$	-
Total	\$	5,967,761	\$	4,716,402	\$	493,567	\$	543,575	\$	2,197	\$	47,696	\$	100,257	\$	60,983	\$	1,664	\$	1,421



2006 Cost Allocation Information Filing

Brantford Power Inc.

EB-2005-0342 EB-2007-0001

Tuesday, January 30, 2007

Sheet 02.1 Line Transformer Worksheet - Second Run

Line Transformers Demand Unit Cost for PLCC
Adjustment to Customer Related Cost
Allocation by rate classification

<u>Description</u>	Total	1	2
		Residential	GS <50
Depreciation on Acct 1850 Line Transformers	\$309,288	\$153,199	\$65,082
Depreciation on General Plant Assigned to Line Transformers	\$36,511	\$18,085	\$7,683
Acct 5035 - Overhead Distribution Transformers- Operation	\$53,160	\$26,331	\$11,186
Acct 5055 - Underground Distribution Transformers - Operation	\$1,317	\$652	\$277
Acct 5160 - Maintenance of Line Transformers	\$461,150	\$228,420	\$97,038
Allocation of General Expenses	\$102,867	\$50,953	\$21,646
Admin and General Assigned to Line Transformers	\$464,360	\$227,909	\$97,571
PILs on Line Transformers	\$233,337	\$115,578	\$49,100
Debt Return on Line Transformers	\$238,478	\$118,125	\$50,182
Equity Return on Line Transformers	\$352,088	\$174,398	\$74,088
Total	\$2,252,556	\$1,113,650	\$473,854
Line Transformer NCP	407,718	201,954	85,795
PLCC Amount	57,920	51,373	3,934
Adjustment to Customer Related Cost for PLCC	\$316,400	\$283,289	\$21,730
General Plant - Gross Assets	\$1,928,869	\$1,156,804	\$228,731
General Plant - Accumulated Depreciation	(\$892,075)	(\$535,005)	(\$105,785)
General Plant - Net Fixed Assets	\$1,036,794	\$621,799	\$122,946
General Plant - Depreciation	\$262,389	\$157,363	\$31,115
Total Net Fixed Assets Excluding General Plant	\$44,518,788	\$26,699,334	\$5,279,161
Total Administration and General Expense	\$3,634,761	\$2,388,994	\$426,205
Total O&M	\$4,045,531	\$2,677,193	\$473,952
<u>Line Transformer Rate Base</u>			
Acct 1850 - Line Transformers - Gross Assets	\$7,177,573	\$3,555,243	\$1,510,349
Line Transformers - Accumulated Depreciation	(\$982,785)	(\$486,800)	(\$206,804)
Line Transformers - Net Fixed Assets	\$6,194,788	\$3,068,443	\$1,303,545
General Plant Assigned to Line Transformers - NFA	\$144,270	\$71,461	\$30,358
Line Transformer Net Fixed Assets Including General Plant	\$6,339,058	\$3,139,904	\$1,333,903
<u>General Expenses</u>			
Acct 5005 - Operation Supervision and Engineering	\$97,159	\$46,712	\$14,147
Acct 5010 - Load Dispatching	\$5,620	\$2,702	\$818
Acct 5085 - Miscellaneous Distribution Expense	\$94,803	\$45,579	\$13,804
Acct 5105 - Maintenance Supervision and Engineering	\$248,341	\$119,397	\$36,161
Total	\$445,924	\$214,391	\$64,931
Acct 1850 - Line Transformers - Gross Assets	\$7,177,573	\$3,555,243	\$1,510,349
Acct 1815 - 1855	\$31,114,535	\$14,959,206	\$4,530,617

3	4	5	6	7	8	9
GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
\$85,216	\$0	\$0	\$0	\$5,022	\$0	\$769
\$10,060	\$0	\$0	\$0	\$593	\$0	\$91
\$14,647	\$0	\$0	\$0	\$863	\$0	\$132
\$363	\$0	\$0	\$0	\$21	\$0	\$3
\$127,058	\$0	\$0	\$0	\$7,488	\$0	\$1,146
\$28,342	\$0	\$0	\$0	\$1,670	\$0	\$256
\$130,089	\$0	\$0	\$0	\$7,662	\$0	\$1,130
\$64,290	\$0	\$0	\$0	\$3,789	\$0	\$580
\$65,707	\$0	\$0	\$0	\$3,872	\$0	\$593
\$97,009	\$0	\$0	\$0	\$5,717	\$0	\$875
\$622,780	\$0	\$0	\$0	\$36,698	\$0	\$5,575
112,336	0	0	0	6,620	0	1,013
485	0	0	0	738	553	837
\$2,688	\$0	\$0	\$0	\$4,090	\$0	\$4,603
\$422,810	\$0	\$0	\$21,729	\$24,637	\$11,469	\$10,747
(\$195,544)	\$0	\$0	(\$10,049)	(\$11,394)	(\$5,304)	(\$4,970)
\$227,266	\$0	\$0	\$11,680	\$13,243	\$6,165	\$5,777
\$57,516	\$0	\$0	\$2,956	\$3,351	\$1,560	\$1,462
\$9,758,562	\$0	\$0	\$501,506	\$568,639	\$264,716	\$248,043
\$642,381	\$0	\$0	\$25,984	\$37,679	\$23,889	\$26,912
\$701,532	\$0	\$0	\$27,618	\$41,175	\$26,787	\$30,533
\$1,977,593	\$0	\$0	\$0	\$116,547	\$0	\$17,841
(\$270,781)	\$0	\$0	\$0	(\$15,958)	\$0	(\$2,443)
\$1,706,812	\$0	\$0	\$0	\$100,589	\$0	\$15,399
\$39,750	\$0	\$0	\$0	\$2,343	\$0	\$359
\$1,746,562	\$0	\$0	\$0	\$102,931	\$0	\$15,757
\$28,759	\$0	\$0	\$1,710	\$1,464	\$1	\$237
\$1,664	\$0	\$0	\$99	\$85	\$0	\$14
\$28,062	\$0	\$0	\$1,669	\$1,429	\$1	\$231
\$73,510	\$0	\$0	\$4,372	\$3,742	\$4	\$606
\$131,994	\$0	\$0	\$7,850	\$6,719	\$7	\$1,088
\$1,977,593	\$0	\$0	\$0	\$116,547	\$0	\$17,841
\$9,209,971	\$0	\$0	\$547,725	\$468,853	\$461	\$75,947



2006 Cost Allocation Information Filing

Brantford Power Inc.
EB-2005-0342 EB-2007-0001
Tuesday, January 30, 2007

Sheet O2.2 Primary Cost PLCC Adjustment Worksheet - Second Run

Primary Conductors and Poles Cost Pool Demand Unit Cost for
 PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total	Rate Classification				
		Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	\$217,629	\$57,888	\$24,639	\$104,958	\$0	\$0
Depreciation on Acct 1835-4 Primary Overhead Conductors	\$141,326	\$37,592	\$16,000	\$68,159	\$0	\$0
Depreciation on Acct 1840-4 Primary Underground Conduit	\$42,022	\$11,178	\$4,757	\$20,266	\$0	\$0
Depreciation on Acct 1845-4 Primary Underground Conductors	\$101,516	\$27,003	\$11,493	\$48,959	\$0	\$0
Depreciation on General Plant Assigned to Primary C&P	\$59,272	\$15,766	\$6,710	\$28,586	\$0	\$0
Primary C&P Operations and Maintenance	\$424,106	\$90,964	\$42,718	\$226,624	\$0	\$0
Allocation of General Expenses	\$167,024	\$44,428	\$18,910	\$80,552	\$0	\$0
Admin and General Assigned to Primary C&P	\$386,967	\$81,172	\$38,414	\$207,516	\$0	\$0
PLs on Primary C&P	\$378,796	\$100,758	\$42,885	\$182,685	\$0	\$0
Debt Return on Primary C&P	\$387,143	\$102,978	\$43,830	\$186,711	\$0	\$0
Equity Return on Primary C&P	\$571,575	\$152,037	\$64,711	\$275,658	\$0	\$0
Total	\$2,877,375	\$721,765	\$315,067	\$1,430,673	\$0	\$0
Primary NCP	759,236	201,954	85,957	366,163	0	0
PLCC Amount	58,069	51,373	3,938	626	0	0
Adjustment to Customer Related Cost for PLCC	\$206,129	\$183,602	\$14,433	\$2,444	\$0	\$0
General Plant - Gross Assets	\$1,928,869	\$1,156,804	\$228,731	\$422,810	\$0	\$0
General Plant - Accumulated Depreciation	(\$892,075)	(\$535,005)	(\$105,785)	(\$195,544)	\$0	\$0
General Plant - Net Fixed Assets	\$1,036,794	\$621,799	\$122,946	\$227,266	\$0	\$0
General Plant - Depreciation	\$262,389	\$157,363	\$31,115	\$57,516	\$0	\$0
Total Net Fixed Assets Excluding General Plant	\$44,518,788	\$26,699,334	\$5,279,161	\$9,758,562	\$0	\$0
Total Administration and General Expense	\$3,634,761	\$2,388,994	\$426,205	\$642,381	\$0	\$0
Total O&M	\$4,045,531	\$2,677,193	\$473,952	\$701,532	\$0	\$0
Primary Conductors and Poles Gross Assets						
Acct 1830-4 Primary Poles, Towers & Fixtures	\$4,992,782	\$1,328,060	\$565,256	\$2,407,913	\$0	\$0
Acct 1835-4 Primary Overhead Conductors	\$3,242,264	\$862,429	\$367,072	\$1,563,675	\$0	\$0
Acct 1840-4 Primary Underground Conduit	\$987,781	\$262,746	\$111,831	\$476,396	\$0	\$0
Acct 1845-4 Primary Underground Conductors	\$2,431,383	\$646,738	\$275,268	\$1,172,605	\$0	\$0
Subtotal	\$11,654,210	\$3,099,974	\$1,319,428	\$5,620,578	\$0	\$0
Primary Conductors and Poles Accumulated Depreciation						
Acct 1830-4 Primary Poles, Towers & Fixtures	(\$691,949)	(\$184,056)	(\$78,339)	(\$333,713)	\$0	\$0
Acct 1835-4 Primary Overhead Conductors	(\$449,345)	(\$119,524)	(\$50,872)	(\$216,710)	\$0	\$0
Acct 1840-4 Primary Underground Conduit	(\$133,606)	(\$35,539)	(\$15,126)	(\$64,436)	\$0	\$0
Acct 1845-4 Primary Underground Conductors	(\$322,769)	(\$85,855)	(\$36,542)	(\$155,665)	\$0	\$0
Subtotal	(\$1,597,672)	(\$424,974)	(\$180,880)	(\$770,523)	\$0	\$0
Primary Conductor & Poles - Net Fixed Assets	\$10,056,538	\$2,675,000	\$1,138,548	\$4,850,054	\$0	\$0
General Plant Assigned to Primary C&P - NFA	\$234,206	\$62,298	\$26,516	\$112,953	\$0	\$0
Primary C&P Net Fixed Assets Including General Plant	\$10,290,744	\$2,737,297	\$1,165,063	\$4,963,007	\$0	\$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1835-3 Bulk Overhead Conductors	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1840-3 Bulk Underground Conduit	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1845-3 Bulk Underground Conductors	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1830-5 Secondary Poles, Towers & Fixtures	\$1,095,977	\$895,267	\$166,868	\$0	\$0	\$0
Acct 1835-5 Secondary Overhead Conductors	\$1,324,305	\$1,081,781	\$201,632	\$0	\$0	\$0
Acct 1840-5 Secondary Underground Conduit	\$4,211,066	\$3,439,882	\$641,157	\$0	\$0	\$0
Acct 1845-5 Secondary Underground Conductors	\$2,336,035	\$1,908,231	\$355,673	\$0	\$0	\$0
Subtotal	\$8,967,382	\$7,325,161	\$1,365,331	\$0	\$0	\$0
Operations and Maintenance						
Acct 5020 Overhead Distribution Lines & Feeders - Labour	\$402	\$157	\$49	\$150	\$0	\$0
Acct 5025 Overhead Distribution Lines & Feeders - Other	\$9,005	\$3,522	\$1,099	\$3,356	\$0	\$0
Acct 5040 Underground Distribution Lines & Feeders - Labour	\$1,196	\$751	\$166	\$198	\$0	\$0
Acct 5045 Underground Distribution Lines & Feeders - Other	\$5,738	\$3,603	\$797	\$949	\$0	\$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	\$0	\$0	\$0	\$0	\$0	\$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	\$0	\$0	\$0	\$0	\$0	\$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	\$115,467	\$42,163	\$13,884	\$45,663	\$0	\$0
Acct 5125 Maintenance of Overhead Conductors & Devices	\$218,403	\$92,985	\$27,199	\$74,785	\$0	\$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	\$213,558	\$83,528	\$26,072	\$79,600	\$0	\$0
Acct 5145 Maintenance of Underground Conduit	\$61,339	\$43,686	\$8,884	\$5,621	\$0	\$0
Acct 5150 Maintenance of Underground Conductors & Devices	\$66,274	\$35,518	\$8,771	\$16,301	\$0	\$0
Total	\$691,381	\$305,911	\$86,921	\$226,624	\$0	\$0
General Expenses						
Acct 5005 - Operation Supervision and Engineering	\$97,159	\$46,712	\$14,147	\$28,759	\$0	\$0
Acct 5010 - Load Dispatching	\$5,620	\$2,702	\$818	\$1,664	\$0	\$0
Acct 5085 - Miscellaneous Distribution Expense	\$94,803	\$45,579	\$13,804	\$28,062	\$0	\$0
Acct 5105 - Maintenance Supervision and Engineering	\$248,341	\$119,397	\$36,161	\$73,510	\$0	\$0
Total	\$445,924	\$214,391	\$64,931	\$131,994	\$0	\$0
Primary Conductors and Poles Gross Assets	\$11,654,210	\$3,099,974	\$1,319,428	\$5,620,578	\$0	\$0
Acct 1815 - 1855	\$31,114,535	\$14,959,206	\$4,530,617	\$9,209,971	\$0	\$0

6	7	8	9	10	11
Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
\$7,987	\$1,898	\$0	\$291	\$16,604	\$3,365
\$5,186	\$1,232	\$0	\$189	\$10,783	\$2,185
\$1,542	\$366	\$0	\$56	\$3,206	\$650
\$3,725	\$885	\$0	\$136	\$7,745	\$1,569
\$2,175	\$517	\$0	\$79	\$4,522	\$916
\$17,244	\$2,982	\$0	\$456	\$35,852	\$7,265
\$6,129	\$1,456	\$0	\$223	\$12,744	\$2,582
\$16,225	\$2,729	\$0	\$402	\$33,778	\$6,731
\$13,901	\$3,303	\$0	\$506	\$28,901	\$5,856
\$14,207	\$3,376	\$0	\$517	\$29,538	\$5,985
\$20,976	\$4,984	\$0	\$763	\$43,610	\$8,837
\$109,298	\$23,728	\$0	\$3,617	\$227,283	\$45,943
27,862	6,620	0	1,013	57,928	11,738
2	738	553	837	2	2
\$6	\$2,645	\$0	\$2,987	\$6	\$6
\$21,729	\$24,637	\$11,469	\$10,747	\$44,810	\$7,131
(\$10,049)	(\$11,394)	(\$5,304)	(\$4,970)	(\$20,724)	(\$3,298)
\$11,680	\$13,243	\$6,165	\$5,777	\$24,086	\$3,833
\$2,956	\$3,351	\$1,560	\$1,462	\$6,096	\$970
\$501,506	\$568,639	\$264,716	\$248,043	\$1,034,236	\$164,590
\$25,984	\$37,679	\$23,889	\$26,912	\$53,032	\$9,685
\$27,618	\$41,175	\$26,787	\$30,533	\$56,290	\$10,452
\$183,225	\$43,536	\$0	\$6,665	\$380,936	\$77,191
\$118,985	\$28,272	\$0	\$4,328	\$247,376	\$50,127
\$36,250	\$8,613	\$0	\$1,319	\$75,365	\$15,272
\$89,227	\$21,201	\$0	\$3,246	\$185,508	\$37,591
\$427,686	\$101,622	\$0	\$15,557	\$889,185	\$180,180
(\$25,393)	(\$6,034)	\$0	(\$924)	(\$52,794)	(\$10,698)
(\$16,490)	(\$3,918)	\$0	(\$600)	(\$34,284)	(\$6,947)
(\$4,903)	(\$1,165)	\$0	(\$178)	(\$10,194)	(\$2,066)
(\$11,845)	(\$2,814)	\$0	(\$431)	(\$24,626)	(\$4,990)
(\$58,631)	(\$13,931)	\$0	(\$2,133)	(\$121,898)	(\$24,701)
\$369,055	\$87,691	\$0	\$13,424	\$767,287	\$155,480
\$8,595	\$2,042	\$0	\$313	\$17,869	\$3,621
\$377,650	\$89,733	\$0	\$13,737	\$785,156	\$159,101
\$0	\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0	\$0
\$0	\$29,348	\$0	\$4,493	\$0	\$0
\$0	\$35,463	\$0	\$5,429	\$0	\$0
\$0	\$112,765	\$0	\$17,263	\$0	\$0
\$0	\$62,555	\$0	\$9,576	\$0	\$0
\$0	\$240,131	\$0	\$36,760	\$0	\$0
\$11	\$5	\$0	\$1	\$24	\$5
\$255	\$115	\$0	\$18	\$531	\$108
\$15	\$25	\$0	\$4	\$31	\$6
\$72	\$118	\$0	\$18	\$150	\$30
\$0	\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0	\$0
\$3,475	\$1,382	\$0	\$212	\$7,224	\$1,464
\$5,691	\$3,048	\$0	\$467	\$11,831	\$2,397
\$6,057	\$2,738	\$0	\$419	\$12,593	\$2,552
\$428	\$1,432	\$0	\$219	\$889	\$180
\$1,240	\$1,164	\$0	\$178	\$2,579	\$523
\$17,244	\$10,028	\$0	\$1,535	\$35,852	\$7,265
\$1,710	\$1,464	\$1	\$237	\$3,650	\$577
\$99	\$85	\$0	\$14	\$205	\$33
\$1,669	\$1,429	\$1	\$231	\$3,464	\$563
\$4,372	\$3,742	\$4	\$606	\$9,074	\$1,476
\$7,850	\$6,719	\$7	\$1,088	\$16,293	\$2,650
\$427,686	\$101,622	\$0	\$15,557	\$889,185	\$180,180
\$547,725	\$468,853	\$461	\$75,947	\$1,136,833	\$184,922



2006 Cost Allocation Information Filing
Brantford Power Inc.
EB-2005-0342 EB-2007-0001
Tuesday, January 30, 2007
Sheet 02.3 Secondary Cost PLCC Adjustment Worksheet - Second Run

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	\$47,772	\$39,024	\$7,274	\$0	\$0	\$0	\$0	\$1,279
Depreciation on Acct 1835-5 Secondary Overhead Conductors	\$86,807	\$75,581	\$9,891	\$0	\$0	\$0	\$0	\$1,354
Depreciation on Acct 1840-5 Secondary Underground Conduit	\$275,609	\$234,563	\$30,697	\$0	\$0	\$0	\$0	\$6,064
Depreciation on Acct 1845-5 Secondary Underground Conductors	\$150,054	\$127,707	\$16,713	\$0	\$0	\$0	\$0	\$3,302
Depreciation on General Plant Assigned to Secondary C&P	\$45,891	\$37,323	\$6,957	\$0	\$0	\$0	\$0	\$1,224
Secondary C&P Operations and Maintenance	\$361,275	\$214,947	\$44,204	\$0	\$0	\$0	\$0	\$7,046
Allocation of General Expenses	\$128,518	\$104,982	\$19,567	\$0	\$0	\$0	\$0	\$3,441
Admin and General Assigned to Primary C&P	\$238,957	\$191,808	\$39,751	\$0	\$0	\$0	\$0	\$6,448
PLS on Secondary C&P	\$292,201	\$236,526	\$44,459	\$0	\$0	\$0	\$0	\$7,219
Debt Return on Secondary C&P	\$298,436	\$243,782	\$45,438	\$0	\$0	\$0	\$0	\$7,992
Equity Return on Secondary C&P	\$440,608	\$359,918	\$67,085	\$0	\$0	\$0	\$0	\$11,799
Total	\$2,273,727	\$1,868,161	\$332,034	\$0	\$0	\$0	\$0	\$58,368
Secondary NCP	247,230	201,954	37,642	0	0	0	0	6,620
PLCC Amount	\$74,438	\$1,373	\$3,938	\$0	\$0	\$0	\$0	738
Adjustment to Customer Related Cost for PLCC	\$525,723	\$475,221	\$34,733	\$0	\$0	\$0	\$0	\$6,505
General Plant - Gross Assets	\$1,928,869	\$1,156,804	\$228,731	\$422,810	\$0	\$0	\$21,729	\$24,637
General Plant - Accumulated Depreciation	(\$892,075)	(\$535,005)	(\$105,785)	(\$195,544)	\$0	\$0	(\$10,049)	(\$11,394)
General Plant - Net Fixed Assets	\$1,036,794	\$621,799	\$122,946	\$227,266	\$0	\$0	\$11,680	\$13,243
General Plant - Depreciation	\$262,389	\$157,363	\$31,115	\$57,516	\$0	\$0	\$2,956	\$3,351
Total Net Fixed Assets Excluding General Plant	\$44,518,788	\$26,699,334	\$5,279,161	\$9,758,562	\$0	\$0	\$501,506	\$568,639
Total Administration and General Expense	\$3,634,761	\$2,388,994	\$426,205	\$642,381	\$0	\$0	\$25,984	\$37,679
Total O&M	\$4,045,531	\$2,677,193	\$473,952	\$701,532	\$0	\$0	\$27,618	\$41,175
Secondary Conductors and Poles Gross Plant								
Acct 1830-5 Secondary Poles, Towers & Fixtures	\$1,095,977	\$895,267	\$166,868	\$0	\$0	\$0	\$0	\$29,348
Acct 1835-5 Secondary Overhead Conductors	\$1,324,305	\$1,081,781	\$201,632	\$0	\$0	\$0	\$0	\$35,463
Acct 1840-5 Secondary Underground Conduit	\$4,211,066	\$3,439,892	\$641,157	\$0	\$0	\$0	\$0	\$112,785
Acct 1845-5 Secondary Underground Conductors	\$2,336,035	\$1,908,231	\$355,673	\$0	\$0	\$0	\$0	\$62,555
Subtotal	\$8,967,382	\$7,325,161	\$1,365,331	\$0	\$0	\$0	\$0	\$240,131
Secondary Conductors and Poles Accumulated Depreciation								
Acct 1830-5 Secondary Poles, Towers & Fixtures	(\$151,891)	(\$124,075)	(\$23,126)	\$0	\$0	\$0	\$0	(\$4,067)
Acct 1835-5 Secondary Overhead Conductors	(\$163,535)	(\$146,924)	(\$27,944)	\$0	\$0	\$0	\$0	(\$4,915)
Acct 1840-5 Secondary Underground Conduit	(\$569,593)	(\$465,282)	(\$86,723)	\$0	\$0	\$0	\$0	(\$15,253)
Acct 1845-5 Secondary Underground Conductors	(\$310,112)	(\$253,320)	(\$47,216)	\$0	\$0	\$0	\$0	(\$8,304)
Subtotal	(\$1,215,131)	(\$992,601)	(\$185,010)	\$0	\$0	\$0	\$0	(\$32,539)
Secondary Conductor & Poles - Net Fixed Assets	\$7,752,251	\$6,332,560	\$1,180,321	\$0	\$0	\$0	\$0	\$207,592
General Plant Assigned to Secondary C&P - NFA	\$180,542	\$147,478	\$27,488	\$0	\$0	\$0	\$0	\$4,835
Secondary C&P Net Fixed Assets Including General Plant	\$7,932,793	\$6,480,039	\$1,207,809	\$0	\$0	\$0	\$0	\$212,426
Acct 1830-3 Bulk Poles, Towers & Fixtures	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1835-3 Bulk Overhead Conductors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1840-3 Bulk Underground Conduit	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1845-3 Bulk Underground Conductors	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Subtotal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Acct 1830-4 Primary Poles, Towers & Fixtures	\$4,992,782	\$1,328,060	\$565,256	\$2,407,913	\$0	\$0	\$183,225	\$43,536
Acct 1835-4 Primary Overhead Conductors	\$3,242,264	\$262,429	\$367,072	\$1,563,675	\$0	\$0	\$118,985	\$28,272
Acct 1840-4 Primary Underground Conduit	\$987,781	\$262,746	\$111,831	\$478,386	\$0	\$0	\$36,250	\$8,613
Acct 1845-4 Primary Underground Conductors	\$2,431,383	\$646,738	\$275,268	\$1,172,605	\$0	\$0	\$89,227	\$21,201
Subtotal	\$11,654,210	\$3,099,974	\$1,319,428	\$5,620,578	\$0	\$0	\$427,686	\$101,622
Operations and Maintenance								
Acct 5020 Overhead Distribution Lines & Feeders - Labour	\$402	\$157	\$49	\$150	\$0	\$0	\$11	\$5
Acct 5025 Overhead Distribution Lines & Feeders - Other	\$9,005	\$3,522	\$1,099	\$3,356	\$0	\$0	\$285	\$115
Acct 5040 Underground Distribution Lines & Feeders - Labour	\$1,196	\$751	\$166	\$198	\$0	\$0	\$15	\$25
Acct 5045 Underground Distribution Lines & Feeders - Other	\$3,738	\$3,623	\$797	\$949	\$0	\$0	\$72	\$118
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	\$115,467	\$42,163	\$13,884	\$45,663	\$0	\$0	\$3,475	\$1,382
Acct 5125 Maintenance of Overhead Conductors & Devices	\$218,403	\$92,985	\$27,199	\$74,785	\$0	\$0	\$5,691	\$3,048
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	\$213,558	\$83,528	\$26,072	\$79,600	\$0	\$0	\$6,057	\$2,738
Acct 5145 Maintenance of Underground Conduit	\$91,339	\$43,686	\$8,884	\$35,621	\$0	\$0	\$428	\$1,432
Acct 5150 Maintenance of Underground Conductors & Devices	\$66,274	\$35,518	\$8,771	\$16,301	\$0	\$0	\$1,240	\$1,164
Total	\$691,381	\$305,911	\$86,921	\$226,624	\$0	\$0	\$17,244	\$10,028
General Expenses								
Acct 5005 - Operation Supervision and Engineering	\$97,159	\$46,712	\$14,147	\$28,758	\$0	\$0	\$1,710	\$1,464
Acct 5010 - Load Dispatching	\$5,620	\$2,702	\$818	\$1,664	\$0	\$0	\$99	\$85
Acct 5085 - Miscellaneous Distribution Expense	\$94,803	\$45,579	\$13,804	\$28,062	\$0	\$0	\$1,669	\$1,429
Acct 5105 - Maintenance Supervision and Engineering	\$248,341	\$119,397	\$36,161	\$73,510	\$0	\$0	\$4,372	\$3,742
Total	\$445,924	\$214,391	\$64,931	\$131,994	\$0	\$0	\$7,850	\$6,719
Secondary Conductors and Poles Gross Assets	\$8,967,382	\$7,325,161	\$1,365,331	\$0	\$0	\$0	\$0	\$240,131
Acct 1815 - 1855	\$31,114,535	\$14,959,206	\$4,530,617	\$9,209,971	\$0	\$0	\$547,725	\$468,853

ATTACHMENT P

REFERENCE: OEB STAFF QUESTION 12.1b

DATE 16-Apr-08

NAME OF UTILITY Brantford Power Inc.
 NAME OF CONTACT Heather Wyatt
 E-MAIL ADDRESS hwyatt@brantford.ca
 PHONE NUMBER 519-751-3522 ext. 3269

LICENCE NUMBER ED-XXXX-XXXX
 DOCID NUMBER RP-2005-XXXX
 EB-2005-XXXX

Annual Interest Rate: 4.59% Consult OEB website at:
 Effective Oct 1/07 5.14% http://www.oeb.gov.on.ca/html/en/industryrelations/usesguidesandforms_regulatory_prescribedinterestrates.htm

This column should reconcile with Dec 31/06 trial balances.

Deferred Charge Accounts

Account Description	Account Number	Dec 31/06 Balance			Apply for Disposal?	Jan1/07 to Apr30/07			May1/07 to Dec31/07			Jan1 to Apr30/08			May1 to Dec31/08		
		Principal Portion	Accum. Interest	Total		Interest	Other	Balance	Interest	Other	Balance	Interest	Other	Balance	Interest	Other	Balance
Unrecovered Plant and Regulatory Study Costs	1505				NO												
Other Regulatory Assets	1508	82,289	2,930	84,619	YES	1,259	-	85,878	2,631	88,509	1,409.88	89,919	2,820	-	92,739		
Preliminary Survey and Investigation Charges	1510				NO												
Emission Allowance Inventory	1515				NO												
Emission Allowances Withheld	1516				NO												
Retail Cost Variance Account - Retail	1518	19,105	(1,076)	18,029	YES	190	(5,357)	12,862	514	4,865	18,041	322.00	1,000	19,363	695	2,000	22,058
Power Purchase Variance Account	1520				NO												
Misc. Deferred Debits - incl. Rebate Cheques	1525	7,099	341	7,440	YES	109	-	7,549	227	7,776	121.63	7,897	249	8,141			
Deferred Losses from Disposition of Utility Plant	1530				NO												
Unamortized Loss on Reacquired Debt	1540				NO												
Development Charge Deposits/Receivables	1545				NO												
Retail Cost Variance Account - STR	1548	197,249	27,464	224,713	YES	3,181	34,245	262,139	7,637	9,675	279,351	4,301.00	36,600	320,252	9,686	11,200	341,138
LV Variance Account	1550	(87,158)	(911)	(88,069)	YES	(1,229)	(34,559)	(103,857)	(4,231)	(70,080)	(178,188)	3,175.00	(36,000)	(217,343)	(7,120)		(224,463)
Smart Meter Capital Variance Account	1555	(80,490)	(1,042)	(81,532)	NO	(1,440)	(83,788)	(116,760)	(3,497)	(29,895)	(150,152)	2,205.85	4,679	(147,679)	(4,269)	10,400	(141,547)
Smart Meters O&A Variance Account	1556	12,808	290	13,098	NO	108	(1,802)	11,464	337	11,801	168.38	11,969	337	12,306			
Deferred Development Costs	1560				NO												
Deferred Payments in Lieu of Taxes	1562	(5,218,893)	(1,089,122)	(6,317,815)	NO	(79,846)		(6,397,661)	(168,688)	(6,564,529)	89,413.61	(6,653,943)	(178,827)		(6,832,770)		
PILS Contra Account	1563	5,218,893	1,089,122	6,317,815	NO	79,846		6,397,661	168,688	6,564,529	89,413.61	6,653,943	178,827		6,832,770		
CDM Expenditures and Recoveries	1565	(26,134)		(26,134)	YES	-	(76,310)	(102,445)	-	12,021	(89,824)	-	-	(89,824)	-	-	(89,824)
CDM Contra Account	1566	(1,450)		(1,450)	YES	-		(1,450)	-	(1,450)	-	-	-	(1,450)	-	-	(1,450)
Qualifying Transition Costs	1570				YES												
Pre-Market Opening Energy Variances Total	1571	(123,896)	(208,423)	(333,319)	YES	-	-	(333,319)	-	(333,319)	-	(333,319)	-	-	(333,319)	-	-
Extra-Ordinary Event Losses	1572				NO												
Deferred Rate Impact Amounts	1574				NO												
RSVA - Wholesale Market Service Charge	1580	(719,977)	(86,151)	(786,128)	YES	(12,452)	(499,008)	(1,297,588)	(48,412)	(602,648)	(1,048,648)	34,036.00	(439,900)	(2,422,484)	(90,656)	(878,050)	(3,391,190)
RSVA - One-time Wholesale Market Service	1582	284,945	51,023	315,968	YES	4,054		320,022	8,472	328,494	4,539.39	333,033	9,079		342,112		
RSVA - Retail Transmission Network Charge	1584	536,562	(24,082)	514,490	YES	7,539	(194,434)	327,585	16,332	260,829	604,756	10,365.27	200	615,321	20,782	1,800	637,883
RSVA - Retail Transmission Connection Charge	1586	(39,902)	(25,365)	(65,267)	YES	(2,458)	(357,969)	(425,394)	(17,108)	(316,287)	(757,789)	14,140.00	(299,880)	(1,071,809)	(34,645)	1,950	(1,104,504)
RSVA - Power	1588	74,039	(383,171)	(309,132)	YES	(2,778)	(592,784)	(904,674)	8,304	1,623,239	726,869	19,163.00	37,200	783,232	40,438	88,400	912,070
Deferred PILS Account	1592				NO												
Other Deferred Credits	2425				NO												
Sub-totals		137,109	(629,763)	(492,674)		(3,857)	(1,761,446)	(2,257,978)	(28,694)	893,119	(1,393,763)	(13,166)	(696,001)	(2,102,920)	(62,630)	(782,300)	(2,817,850)

Recovery of Regulatory Asset Balances (acct #1690)

Approved Balance	3,186,284																
Less Period Disposals							892,288			1,717,484			899,320			(1,311,473)	
Plus Period Interest									(15,849)			(30,424)		(84,130)			
Balance to (Refund) or Recover from 2006	3,186,284							2,308,733		673,601		(358,143)				881,201	
																Total Reg Asset	(2,026,650)

Bridge Year (2007) Forecast

Customer Class	Metric	KW	KWhs	# Customers	EDR 2006 Approved Rates*	EDR 2007 Approved Rates**	Jan107 to Apr30/07 Disposal	May107 to Dec31/07 Disposal	Proportional Allocation
Residential	KWhs	0	285,682,423	33,287	0.0040	0.0040	413,157	762,353	44%
GS < 50 KW	KWhs	0	108,188,798	2,838	0.0023	0.0023	83,133	185,905	10%
GS > 50 Non TOU	KW	1,485,350	597,254,915	409	0.7812	0.7812	391,521	781,488	46%
GS > 50 TOU	KW	0	0	0	0.0000	0.0000	-	-	0%
Intermediate	KW	0	0	0	0.0000	0.0000	-	-	0%
Large Users	KW	0	0	0	0.0000	0.0000	-	-	0%
Unmetered Scattered Load	KWhs	0	2,184,787	435	0.0050	0.0050	3,113	7,283	0%
Standby Power	kw	0	0	0	0.0000	0.0000	-	-	0%
Sentinel Lighting	KW	1,787	548,290	788	3.2065	3.2065	1,737	1,221	0%
Street Lighting	KW	22,168	7,084,269	9,773	-0.0518	-0.0518	(373)	(766)	0%
Additional Customer Class 1	kw	0	0	0	0.0000	0.0000	-	-	0%
Additional Customer Class 2							-	-	0%
Additional Customer Class 3							-	-	0%
Additional Customer Class 4							-	-	0%
Totals		1,608,305	1,001,154,460	47,330			892,286	1,717,484	100%

Test Year (2008) Forecast

Customer Class	Metric	KW	KWhs	# Customers	Dx Revenue	# Customers w/Rebate Cheques	Additional Allocator 1	Additional Allocator 2	Additional Allocator 3	EDR 2007 Approved Rates	Jan108 to Apr30/08 Disposal	May 108 to Dec 31/08 Disposal
Residential	KWhs	0	294,990,855	33,818	0	9,248	4,818	-	-	0.0040	393,321	(238,262)
GS < 50 KW	KWhs	0	110,476,190	2,978	0	578	296	-	-	0.0023	84,898	(166,586)
GS > 50 Non TOU	KW	1,658,511	589,877,774	414	0	28	100	-	-	0.7812	417,234	(901,101)
GS > 50 TOU	KW	0	0	0	0	0	-	-	-	0.0000	-	-
Intermediate	KW	0	0	0	0	0	-	-	-	0.0000	-	-
Large Users	KW	0	0	0	0	0	-	-	-	0.0000	-	-
Unmetered Scattered Load	KWhs	0	2,335,344	435	0	0	-	-	-	0.0050	3,892	(3,584)
Standby Power	kw	0	0	0	0	0	-	-	-	0.0000	-	-
Sentinel Lighting	KW	1,787	548,290	788	0	0	-	-	-	3.2065	810	(843)
Street Lighting	KW	25,242	7,244,141	10,856	0	0	-	-	-	-0.0518	(436)	(11,117)
Additional Customer Class 1	kw	0	0	0	0	0	-	-	-	-	-	-
Additional Customer Class 2							-	-	-	-	-	-
Additional Customer Class 3							-	-	-	-	-	-
Additional Customer Class 4							-	-	-	-	-	-
Totals		1,685,540	1,005,573,895	48,187	-	9,854	5,314	-	-		899,320	(1,311,473)

* EDR Approved 2006 rates can be found at http://www.oeb.gov.on.ca/nl/en/consumers/understanding/2006edr_decisions.htm

** EDR Approved 2007 rates can be found at http://www.oeb.gov.on.ca/nl/en/consumers/understanding/2007edr_decisions.htm

Account Description	Account Number	Dec31/06 Balance	Apr 30/08 Balance	Allocation Basis	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Unmetered Scattered Load	Standby Power	Sentinel Lighting
Unrecovered Plant and Regulatory Study Costs	1505	-	-										
Other Regulatory Assets	1508	84,619	89,919	KWh	26,378	9,879	52,756	-	-	-	209	-	49
Preliminary Survey and Investigation Charges	1510	-	-										
Emission Allowance Inventory	1515	-	-										
Emission Allowances Withheld	1516	-	-										
Retail Cost Variance Account - Retail	1518	18,029	19,363	Additional Allocator 1	17,920	1,079	364	-	-	-	-	-	-
Power Purchase Variance Account	1520	-	-										
Misc. Deferred Debits - incl. Rebate Cheques	1525	7,440	7,897	# Customers w/Rebate Cheques	7,337	538	22	-	-	-	-	-	-
Deferred Losses from Disposition of Utility Plant	1530	-	-										
Unamortized Loss on Reacquired Debt	1540	-	-										
Development Charge Deposits/ Receivables	1545	-	-										
Retail Cost Variance Account - STR	1548	224,713	320,252	Additional Allocator 1	296,387	17,839	6,027	-	-	-	-	-	-
LV Variance Account	1550	(68,069)	(217,343)	KWh	(83,759)	(23,878)	(127,517)	-	-	-	(505)	-	(119)
Smart Meter Capital Variance Account	1555	-	-	KWh	-	-	-	-	-	-	-	-	-
Smart Meters OM&A Variance Account	1556	-	-	KWh	-	-	-	-	-	-	-	-	-
Deferred Development Costs	1560	-	-										
Deferred Payments in Lieu of Taxes	1562	-	-	KWh	-	-	-	-	-	-	-	-	-
PILS Contra Account	1563	-	-	KWh	-	-	-	-	-	-	-	-	-
CDM Expenditures and Recoveries	1565	(26,134)	(89,824)	KWh	(26,350)	(9,888)	(52,700)	-	-	-	(209)	-	(49)
CDM Contra Account	1566	(1,450)	(1,450)	KWh	(425)	(159)	(850)	-	-	-	(3)	-	(1)
Qualifying Transition Costs	1570	-	-	# Customers	-	-	-	-	-	-	-	-	-
Pre-Market Opening Energy Variances Total	1571	(333,319)	(333,319)	KWh	(97,781)	(36,620)	(195,561)	-	-	-	(774)	-	(182)
Extra-Ordinary Event Losses	1572	-	-	Dx Revenue	-	-	-	-	-	-	-	-	-
Deferred Rate Impact Amounts	1574	-	-										
RSVA - Wholesale Market Service Charge	1580	(786,128)	(2,422,484)	KWh	(710,650)	(266,143)	(1,421,290)	-	-	-	(5,826)	-	(1,323)
RSVA - One-time Wholesale Market Service	1582	315,968	333,033	KWh	97,697	36,588	195,393	-	-	-	773	-	182
RSVA - Retail Transmission Network Charge	1584	514,490	615,321	KWh	180,508	67,602	361,014	-	-	-	1,429	-	336
RSVA - Retail Transmission Connection Charge	1586	(65,287)	(1,071,809)	KWh	(314,421)	(117,753)	(628,839)	-	-	-	(2,489)	-	(585)
RSVA - Power	1588	(309,132)	783,232	KWh	229,766	86,049	459,528	-	-	-	1,819	-	428
Deferred PILS Account	1592	-	-										
Other Deferred Credits	2425	-	-	# Customers	-	-	-	-	-	-	-	-	-
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	(424,240)	(1,967,210)		(367,393)	(234,849)	(1,351,662)	-	-	-	(5,376)	-	(1,264)
Clear residual 1590 balance as of April 30/08?	NO												
Total to Dispose at May1/08					(367,393)	(234,849)	(1,351,662)	-	-	-	(5,376)	-	(1,264)
Disposal period? - BPI has chosen 1 year to repay credit					(357,393)	(234,849)	(1,351,652)	-	-	-	(5,376)	-	(1,264)
Projected 2008 Rate Riders					(0.0012)	(0.0021)	(0.8160)				(0.0023)		(0.7076)
Rate Determinant					KWh	KWh	KW	KW	KW	KW	KWh	KW	KW

Test Year (2008) Allocations

Customer Class	Metric	KW	KWh	# Customers	KWh for Non TOU Customers	Dx Revenue	# Customers w/Rebate Cheques	Additional Allocator 1	Additional Allocator 2	Additional Allocator 3
Residential	KWhs	0%	29%	70%	30%		93%	93%		
GS < 50 KW	KWhs	0%	11%	6%	11%		7%	6%		
GS > 50 Non TOU	KW	96%	59%	1%	59%		0%	2%		
GS > 50 TOU	KW	0%	0%	0%			0%	0%		
Intermediate	KW	0%	0%	0%				0%		
Large Users	KW	0%	0%	0%				0%		
Unmetered Scattered Load	KWhs	0%	0%	1%	0%			0%		
Standby Power	KW	0%	0%	0%				0%		
Sentinel Lighting	KW	0%	0%	2%				0%		
Street Lighting	KW	1%	1%	21%				0%		
Additional Customer Class 1	KW	0%	0%	0%				0%		
Additional Customer Class 2	KW	0%	0%	0%				0%		
Additional Customer Class 3	KW	0%	0%	0%				0%		
Additional Customer Class 4	KW	0%	0%	0%				0%		
Totals		100%	100%	100%	100%	0%	100%	100%	0%	0%

Account Description	Street Lighting	Additional Customer Class 1	Additional Customer Class 2	Additional Customer Class 3	Additional Customer Class 4	Totals
Unrecovered Plant and Regulatory Study Costs						-
Other Regulatory Assets	648	-	-	-	-	89,919
Preliminary Survey and Investigation Charges						-
Emission Allowance Inventory						-
Emission Allowances Withheld						-
Retail Cost Variance Account - Retail						19,963
Power Purchase Variance Account						-
Misc. Deferred Debits - incl. Rebate Cheques						7,897
Deferred Losses from Disposition of Utility Plant						-
Unamortized Loss on Recquired Debt						-
Development Charge Deposits/ Receivables						-
Retail Cost Variance Account - STR						320,262
LV Variance Account	(1,566)	-	-	-	-	(217,343)
Smart Meter Capital Variance Account						-
Smart Meters OM&A Variance Account						-
Deferred Development Costs						-
Deferred Payments in Lieu of Taxes						-
PILS Contra Account						-
CDM Expenditures and Recoveries	(647)	-	-	-	-	(89,624)
CDM Contra Account	(10)	-	-	-	-	(1,450)
Qualifying Transition Costs						-
Pre-Market Opening Energy Variances Total	(2,401)	-	-	-	-	(333,319)
Extra-Ordinary Event Losses						-
Deferred Rate Impact Amounts						-
RSVA - Wholesale Market Service Charge	(17,452)	-	-	-	-	(2,422,484)
RSVA - One-time Wholesale Market Service	2,399	-	-	-	-	333,033
RSVA - Retail Transmission Network Charge	4,433	-	-	-	-	615,321
RSVA - Retail Transmission Connection Charge	(7,721)	-	-	-	-	(1,071,809)
RSVA - Power	5,642	-	-	-	-	783,232
Deferred PILS Account						-
Other Deferred Credits						-
Sub-total to Dispose at May1/08 or Dec31/06?	(16,676)	-	-	-	-	(1,967,210)
Clear residual 1590 balance as of April 30/08?						-
Total to Dispose at May1/08	(16,676)	-	-	-	-	(1,967,210)
Disposal period? - BPI has chosen 1 year to repay credit	(16,675)	-	-	-	-	(1,967,210)
Projected 2008 Rate Riders	(0.6606)		0.0000			
Rate Determinant	kW		kW			

Checks All Totals Agg to Recover May1/08 or 31/06

Test Year (2008) Allocations

Customer Class
Residential
GS < 50 KW
GS > 50 Non TOU
GS > 50 TOU
Intermediate
Large Users
Unmetered Scattered Load
Standby Power
Sentinel Lighting
Street Lighting
Additional Customer Class 1
Additional Customer Class 2
Additional Customer Class 3
Additional Customer Class 4
Totals

OEB IR 12.1 b) Please provide allocations and rate rider calculations, by individual account, for regulatory deferral and variance accounts being requested for disposition

Account Description	Account Number	Apr 30/08 Balance	Allocation Basis	Residential	GS < 60 KW	GS > 60 Non TOU	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Totals
Other Regulatory Assets <i>rate rider</i>	1508	89,919	KWh	\$ 26,378 <i>0.0000894</i>	\$ 9,879 <i>0.0000894</i>	\$ 52,756 <i>0.0318093</i>	\$ 209 <i>0.0000894</i>	\$ 49 <i>0.0274862</i>	\$ 648 <i>0.0256629</i>	\$ 89,919
Retail Cost Variance Account - Retail <i>rate rider</i>	1518	19,363	Additional Allocator 1	\$ 17,920 <i>0.0000607</i>	\$ 1,079 <i>0.0000098</i>	\$ 364 <i>0.0002197</i>	\$ -	\$ -	\$ -	\$ 19,363
Misc. Deferred Debits - incl. Rebate Cheques <i>rate rider</i>	1525	7,897	# Customers w/Rebate Cheques	\$ 7,337 <i>0.0000249</i>	\$ 538 <i>0.0000049</i>	\$ 22 <i>0.0000134</i>	\$ -	\$ -	\$ -	\$ 7,897
Retail Cost Variance Account - STR <i>rate rider</i>	1548	320,252	Additional Allocator 1	\$ 296,387 <i>0.0010047</i>	\$ 17,839 <i>0.0001615</i>	\$ 6,027 <i>0.0036337</i>	\$ -	\$ -	\$ -	\$ 320,252
LV Variance Account <i>rate rider</i>	1550	(217,343)	KWh	\$ (63,759) <i>(0.0002161)</i>	\$ (23,876) <i>(0.0002161)</i>	\$ (127,517) <i>(0.0768862)</i>	\$ (505) <i>(0.0002161)</i>	\$ (119) <i>(0.0664367)</i>	\$ (1,566) <i>(0.0620297)</i>	\$ (217,343)
CDM Expenditures and Recoveries <i>rate rider</i>	1565	(89,824)	KWh	\$ (26,350) <i>(0.0000893)</i>	\$ (9,868) <i>(0.0000893)</i>	\$ (52,700) <i>(0.0317758)</i>	\$ (209) <i>(0.0000893)</i>	\$ (49) <i>(0.0274570)</i>	\$ (647) <i>(0.0256357)</i>	\$ (89,824)
CDM Contra Account <i>rate rider</i>	1566	(1,450)	KWh	\$ (425) <i>(0.0000014)</i>	\$ (159) <i>(0.0000014)</i>	\$ (850) <i>(0.0005128)</i>	\$ (3) <i>(0.0000014)</i>	\$ (1) <i>(0.0004431)</i>	\$ (10) <i>(0.0004137)</i>	\$ (1,450)
Pre-Market Opening Energy Variances Total <i>rate rider</i>	1571	(333,319)	KWh	\$ (97,781) <i>(0.0003315)</i>	\$ (36,620) <i>(0.0003315)</i>	\$ (195,561) <i>(0.1179135)</i>	\$ (774) <i>(0.0003315)</i>	\$ (182) <i>(0.1018881)</i>	\$ (2,401) <i>(0.0951295)</i>	\$ (333,319)
RSVA - Wholesale Market Service Charge <i>rate rider</i>	1580	(2,422,484)	KWh	\$ (710,650) <i>(0.0024091)</i>	\$ (266,143) <i>(0.0024091)</i>	\$ (1,421,290) <i>(0.8569674)</i>	\$ (5,626) <i>(0.0024091)</i>	\$ (1,323) <i>(0.7404984)</i>	\$ (17,452) <i>(0.6913787)</i>	\$ (2,422,484)
RSVA - One-time Wholesale Market Service <i>rate rider</i>	1582	333,033	KWh	\$ 97,697 <i>0.0003312</i>	\$ 36,588 <i>0.0003312</i>	\$ 195,393 <i>0.1178123</i>	\$ 773 <i>0.0003312</i>	\$ 182 <i>0.1018007</i>	\$ 2,399 <i>0.0950479</i>	\$ 333,033
RSVA - Retail Transmission Network Charge <i>rate rider</i>	1584	615,321	KWh	\$ 180,508 <i>0.0006119</i>	\$ 67,602 <i>0.0006119</i>	\$ 361,014 <i>0.2176734</i>	\$ 1,429 <i>0.0006119</i>	\$ 336 <i>0.1880898</i>	\$ 4,433 <i>0.1756131</i>	\$ 615,321
RSVA - Retail Transmission Connection Charge <i>rate rider</i>	1586	(1,071,809)	KWh	\$ (314,421) <i>(0.0010659)</i>	\$ (117,753) <i>(0.0010659)</i>	\$ (628,839) <i>(0.3791585)</i>	\$ (2,489) <i>(0.0010659)</i>	\$ (585) <i>(0.3276277)</i>	\$ (7,721) <i>(0.3058951)</i>	\$ (1,071,809)
RSVA - Power <i>rate rider</i>	1588	783,232	KWh	\$ 229,766 <i>0.0007789</i>	\$ 86,049 <i>0.0007789</i>	\$ 459,528 <i>0.2770727</i>	\$ 1,819 <i>0.0007789</i>	\$ 428 <i>0.2394163</i>	\$ 5,642 <i>0.2235350</i>	\$ 783,232
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	(1,967,210)		(367,393)	(234,849)	(1,351,652)	(5,376)	(1,264)	(16,675)	(1,967,210)
Clear residual 1590 balance as of April 30/08?	NO									
Total to Dispose at May1/08				(367,393)	(234,849)	(1,351,652)	(5,376)	(1,264)	(16,675)	(1,967,210)
Disposal period? - BPI has chosen 1 year to repay credit				(367,393)	(234,849)	(1,351,652)	(5,376)	(1,264)	(16,675)	(1,967,210)
Projected 2008 Rate Riders				(0.0012)	(0.0021)	(0.8150)	(0.0023)	(0.7076)	(0.6606)	
Rate Determinant				kWh	kWh	kW	kWh	kW	kW	
Rates as calculated by individual account				(0.0012)	(0.0021)	(0.8150)	(0.0023)	(0.7076)	(0.6606)	

OEB IR 12.2 b) Please provide allocations and rate rider calculations, by individual account, using December 31, 2006 plus interest from January 1, 2007 to April 30, 2008

Account Description	Account Number	Jan-Sep/07	4.59%	Oct/07-Apr/08	5.14%	Allocation Basis	Interest from Jan 1/07 to Apr 30/08						Totals	
		monthly	0.38%	monthly	0.43%		Dec 31/06 P+I	Residential	GS < 50 KW	GS > 50 Non TOU	Unmetered Scattered Load	Sentinel Lighting		Street Lighting
	Dec31/06 Principal	Dec31/06 Accum Interest	Dec31/06 Balance	Interest from Jan 1/07 to Apr 30/08	Dec 31/06 P+I Interest									
Other Regulatory Assets rate rider	1508	82,289	2,330	84,619	5,300	89,919	KWh	\$ 26,378 (0.0000894)	\$ 9,879 (0.0000894)	\$ 52,756 (0.0318094)	\$ 209 (0.0000894)	\$ 49 (0.0274862)	\$ 648 (0.0256629)	\$ 89,919
Retail Cost Variance Account - Retail rate rider	1518	19,105	(1,076)	18,029	1,231	19,260	Additional Allocator 1	\$ 17,825 (0.0000804)	\$ 1,073 (0.0000097)	\$ 382 (0.0002185)	\$ -	\$ -	\$ -	\$ 19,260
Misc. Deferred Debits - incl. Rebate Cheques rate rider	1525	7,099	341	7,440	457	7,897	# Customers w/Rebate Cheques	\$ 7,337 (0.0000249)	\$ 538 (0.0000049)	\$ 22 (0.0000134)	\$ -	\$ -	\$ -	\$ 7,897
Retail Cost Variance Account - STR rate rider	1548	197,249	27,464	224,713	12,704	237,417	Additional Allocator 1	\$ 219,725 (0.0007449)	\$ 13,225 (0.0001197)	\$ 4,468 (0.0028938)	\$ -	\$ -	\$ -	\$ 237,417
LV Variance Account rate rider	1550	(67,158)	(911)	(68,069)	(4,326)	(72,395)	KWh	\$ (21,237) (0.0000720)	\$ (7,954) (0.0000720)	\$ (42,475) (0.0256101)	\$ (168) (0.0000720)	\$ (40) (0.0221295)	\$ (522) (0.0206616)	\$ (72,395)
CDM Expenditures and Recoveries rate rider	1565	(26,134)	-	(26,134)	(1,683)	(27,817)	KWh	\$ (8,160) (0.0000277)	\$ (3,056) (0.0000277)	\$ (16,321) (0.0088405)	\$ (65) (0.0000277)	\$ (15) (0.0085031)	\$ (200) (0.0079391)	\$ (27,817)
CDM Contra Account rate rider	1566	(1,450)	-	(1,450)	(93)	(1,543)	KWh	\$ (453) (0.0000015)	\$ (169) (0.0000015)	\$ (905) (0.0005457)	\$ (4) (0.0000015)	\$ (1) (0.0004715)	\$ (11) (0.0004403)	\$ (1,543)
Pre-Market Opening Energy Variances Total rate rider	1571	(123,896)	(209,423)	(333,319)	(7,980)	(341,299)	KWh	\$ (100,122) (0.0003394)	\$ (37,496) (0.0003394)	\$ (200,243) (0.1207365)	\$ (793) (0.0003394)	\$ (186) (0.1043274)	\$ (2,459) (0.0974070)	\$ (341,299)
RSVA - Wholesale Market Service Charge rate rider	1580	(719,977)	(66,151)	(786,128)	(46,373)	(832,501)	KWh	\$ (244,219) (0.0008279)	\$ (91,462) (0.0008279)	\$ (488,435) (0.2945019)	\$ (1,933) (0.0008279)	\$ (455) (0.2544767)	\$ (5,897) (0.2375964)	\$ (832,501)
RSVA - One-time Wholesale Market Service rate rider	1582	264,945	51,023	315,968	17,065	333,033	KWh	\$ 97,697 (0.0003312)	\$ 36,588 (0.0003312)	\$ 195,393 (0.1178123)	\$ 773 (0.0003312)	\$ 182 (0.1018006)	\$ 2,399 (0.0950479)	\$ 333,033
RSVA - Retail Transmission Network Charge rate rider	1584	538,582	(24,092)	514,490	34,689	549,179	KWh	\$ 161,105 (0.0005461)	\$ 60,335 (0.0005461)	\$ 322,208 (0.1942752)	\$ 1,275 (0.0005461)	\$ 300 (0.1678716)	\$ 3,956 (0.1567361)	\$ 549,179
RSVA - Retail Transmission Connection Charge rate rider	1586	(39,902)	(25,365)	(65,267)	(2,570)	(67,837)	KWh	\$ (19,900) (0.0000675)	\$ (7,453) (0.0000675)	\$ (39,800) (0.0239977)	\$ (158) (0.0000675)	\$ (37) (0.0207362)	\$ (489) (0.0193607)	\$ (67,837)
RSVA - Power rate rider	1588	74,039	(383,171)	(309,132)	4,789	(304,363)	KWh	\$ (89,287) (0.0003027)	\$ (33,438) (0.0003027)	\$ (178,572) (0.1076701)	\$ (707) (0.0003027)	\$ (166) (0.0930369)	\$ (2,193) (0.0866654)	\$ (304,363)
Sub-total to Dispose at May1/08 or Dec31/08?	Apr30/08	204,791	(629,031)	(424,240)	13,190	(411,050)		46,688	(59,391)	(391,541)	(1,569)	(369)	(4,867)	(411,050)
Clear residual 1590 balance as of April 30/08?	NO													
Total to Dispose at May1/08								46,688	(59,391)	(391,541)	(1,569)	(369)	(4,867)	(411,050)
Disposal period? - BPI has chosen 1 year to repay credit								46,688	(59,391)	(391,541)	(1,569)	(369)	(4,867)	(411,050)
Projected 2008 Rate Riders Rate Determinant								0.0002 kWh	(0.0005 kWh)	(0.2361 kW)	(0.0007 kWh)	(0.2065 kW)	(0.1928 kW)	
Rates as calculated by individual account								0.0002	(0.0005)	(0.2361)	(0.0007)	(0.2065)	(0.1928)	

ATTACHMENT Q

REFERENCE: OEB STAFF QUESTION 12.2c

CALCULATION OF BALANCES BY ACCOUNT

	December 31/06	Applying for	Carrying Charges		Net Accruals		Adjustments		April 30/08
	Opening	Disposal	Period	LTD	Period	LTD	Period	LTD	Ending
	Balance								Balance
Commodity accounts are classified as follows:									
1588 Retail Settlement Variance Account - Power	(309,132)	Yes	1,092,364	709,193	0	74,039	0	0	783,232
1588 RSVA Power - Sub-account Global Adjustments	0	No	0	0	0	0	0	0	0
Non-commodity accounts are classified in two categories as follows:									
<u>Wholesale and Retail Market Variance Accounts</u>									
1518 Retail Cost Variance Account - Retail	18,029	Yes	1,334	258	0	19,105	0	0	19,363
1548 Retail Cost Variance Account - STR	224,713	Yes	95,539	123,003	0	197,249	0	0	320,252
1580 Retail Settlement Variance Account - Wholesale Market Service Charges	(786,128)	Yes	(1,636,356)	(1,702,507)	0	(719,977)	0	0	(2,422,484)
1582 Retail Settlement Variance Account - One-time Wholesale Market Service	315,968	Yes	17,065	68,088	0	264,945	0	0	333,033
1584 Retail Settlement Variance Account - Retail Transmission Network Charges	514,490	Yes	100,831	76,739	0	538,582	0	0	615,321
1586 Retail Settlement Variance Account - Retail Transmission Connection Charges	(65,267)	Yes	(1,006,542)	(1,031,907)	0	(39,902)	0	0	(1,071,809)
<u>Utility Deferral Accounts</u>									
1508 Other Regulatory Assets	84,619	Yes	5,300	7,630	0	82,289	0	0	89,919
1508 Other Regulatory Assets - Sub-account OEB Cost Assessments	0	No	0	0	0	0	0	0	0
1508 Other Regulatory Assets - Sub-account Pension Contributions	0	No	0	0	0	0	0	0	0
1525 Miscellaneous Deferred Debits	7,440	Yes	458	799	0	7,099	0	0	7,898
1562 Deferred Payments in Lieu of Taxes	(6,317,815)	No	(336,128)	(1,435,250)	0	(5,218,693)	0	0	(6,653,943)
1563 PILs contra account	6,317,815	No	336,128	1,435,250	0	5,218,693	0	0	6,653,943
1565 Conservation and Demand Management Expenditures and Recoveries	(26,134)	Yes	(63,689)	(63,689)	0	(26,134)	0	0	(89,823)
1566 CDM Contra Account	(1,450)	Yes	0	0	0	(1,450)	0	0	(1,450)
1572 Extraordinary Event Losses	0	No	0	0	0	0	0	0	0
1574 Deferred Rate Impact Amounts	0	No	0	0	0	0	0	0	0
2425 Other Deferred Credits	0	No	0	0	0	0	0	0	0
<u>Closed Accounts not classified are as follows:</u>									
1570 Qualifying Transition Costs (closed December 31, 2002)	0	No	0	0	0	0	0	0	0
1571 Pre-Market Opening Energy Variances (closed April 30, 2002)	(333,319)	Yes	0	(209,423)	0	(123,896)	0	0	(333,319)
1550 LV Variance Account	(68,069)	Yes	(149,274)	(150,185)	0	(67,158)	0	0	(217,343)
1555 Smart Meter Capital Variance Account	(81,532)	No	(66,147)	(67,189)	0	(80,490)	0	0	(147,679)
1556 Smart Meter OM&A Variance Account	13,098	No	(1,129)	(839)	0	12,808	0	0	11,969
	(492,674)	Yes	(1,610,246)	(2,240,029)	0	137,109	0	0	(2,102,920)

ATTACHMENT R

REFERENCE: OEB STAFF QUESTION 12.5e

BRANTFORD POWER INC

OEB IR 12.5 e) Please provide a schedule detailing all adjustments that were made to any of the 2006 EDR approved balances.

OTHER ASSETS & DEF CHARGES	Principal as of Dec 31/04 (plus Hydro One)	Interest to Dec 31/04	Claimed on 2006 EDR	Principal	Interest	Adjustments to 2004 balances	Principal **	Interest **	Revised 2004 balances **
1508 OTHER REGULATORY ASSETS	\$ 31,415.00	\$ 502.00	\$ 31,917.00			\$ -	\$ 31,415.00	\$ 502.00	\$ 31,917.00
1525 SECONDARY ENV	\$ 50,657.00	\$ 6,575.00	\$ 57,232.00			\$ -	\$ 50,657.00	\$ 6,575.00	\$ 57,232.00
1570 QUALIFYING TRANSITION COSTS	\$ 1,250,068.00	\$ 268,843.00	\$ 1,518,911.00			\$ -	\$ 1,250,068.00	\$ 268,843.00	\$ 1,518,911.00
1571 PRE-MARKET OPENING ENERGY VAR	\$ 2,660,000.00	\$ 619,990.00	\$ 3,279,990.00	\$ (123,896.00)	\$ (209,423.00)	\$ (333,319.00)	\$ 2,536,104.00	\$ 410,567.00	\$ 2,946,671.00
1580 RSVA WMS	\$ 1,357,615.00	\$ 261,048.00	\$ 1,618,663.00	\$ (211,246.13)	\$ (18,659.07)	\$ (229,905.20)	\$ 1,232,432.87	\$ 387,864.01	\$ 1,620,296.88
				\$ 86,064.00	\$ 145,475.08	\$ 231,539.08			
1582 RSVA ONE-TIME			\$ -	\$ 211,246.13	\$ 18,659.07	\$ 229,905.20	\$ 211,246.13	\$ 18,659.07	\$ 229,905.20
1584 RSVA NW	\$ 1,291,428.00	\$ 158,798.00	\$ 1,450,226.00	\$ 308.00	\$ 520.62	\$ 828.62	\$ 1,291,736.00	\$ 159,318.62	\$ 1,451,054.62
1586 RSVA CN	\$ 1,225,071.00	\$ 136,384.00	\$ 1,361,455.00	\$ (3,915.00)	\$ (6,617.57)	\$ (10,532.57)	\$ 1,221,156.00	\$ 129,766.43	\$ 1,350,922.43
1588 RSVA POWER	\$ (1,692,481.00)	\$ 29,950.00	\$ (1,662,531.00)	\$ 41,439.00	\$ 70,044.87	\$ 111,483.87	\$ (1,651,042.00)	\$ 99,994.87	\$ (1,551,047.13)
Total	\$ 6,173,773.00	\$ 1,482,090.00	\$ 7,655,863.00	\$ -	\$ -	\$ -	\$ 6,173,773.00	\$ 1,482,090.00	\$ 7,655,863.00

** totals used for response to OEB IR 12.8 Jan 1/05 opening balances

reallocated IMO one-time expenses to correct account

corrected split between pre-market consumption and after market opening May 1, 2002 consumption