# OVERVIEW

## MANAGER'S SUMMARY OF OPERATING COSTS

The operating costs presented in this Exhibit represent the annual expenditures required to sustain BPI's distribution operations. BPI follows the Board's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. BPI has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements and this Cost-of-Service Rate Application. BPI is reporting the 2013 Test Year in Modified CGAAP.

Table 4.1 is a reconciliation of the OM&A filed in the Cost-of-Service Rate Application to the Trial balances which are filed with the Board and to the Audited Financial Statements.

**Table 4.1 - OM&A Reconciliation to Audited Financial Statements**

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

*Differences are due to rounding.

A summary of BPI's operating costs for 2008 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and the 2013 Test Year is provided in Table 4.2 below. A summary of the variances as required by the Filing Requirements is provided in Tables 4.2 through 4.8.

## Table 4.2 - Summary of OM&A Expenses

| Description | 2008 Board Approved | 2008 Actuals | 2009 Actuals | 2010 Actuals | 2011 Actuals | 2012 Bridge | 2013 Test |
|---|---|---|---|---|---|---|---|
| Operations | 998,220 | 1,018,908 | 1,057,112 | 1,008,391 | 1,076,343 | 1,111,298 | 1,576,506 |
| Maintenance | 1,725,334 | 1,757,147 | 1,723,356 | 1,681,173 | 1,456,583 | 1,802,869 | 2,033,090 |
| Billing & Collecting | 2,107,836 | 1,978,917 | 2,205,690 | 2,166,453 | 2,045,182 | 2,208,332 | 2,863,215 |
| Community Relations | 127,331 | 113,237 | 127,829 | 131,379 | 115,623 | 169,137 | 232,777 |
| Administrative & General Expense (Includes Special Purpose Charge) | 2,548,053 | 2,825,788 | 2,614,082 | 2,971,323 | 2,318,604 | 2,521,038 | 2,498,437 |
| **Total OM&A Expenses** | **7,506,774** | **7,693,996** | **7,728,069** | **7,958,720** | **7,012,336** | **7,812,674** | **9,204,025** |
| Less Special Purpose Charge | | | | 376,534 | | | |
| **Total Recoverable OM&A Expenses** | **7,506,774** | **7,693,996** | **7,728,069** | **7,582,186** | **7,012,336** | **7,812,674** | **9,204,025** |
| Year over Year % Variance | | 2.5% | 0.4% | 3.0% | -11.9% | 11.4% | 17.8% |
| GDP-IPI | | 2.1% | 2.3% | 1.3% | 1.7% | 2.0% | 1.6% |

BPI is proposing recovery of 2013 Test Year OM&A costs, excluding amortization, PILs and Interest totaling $9,204,025.

## Table 4.3 - Summary OM&A Expense Variances 2008 Approved vs. 2008 Actual

| OM&A: 2008 Approved vs 2008 Actual | | | | |
|---|---|---|---|---|
| Description | 2008 Approved | 2008 Actual | Variance $ | Variance % |
| Operations | $998,220 | 1,018,908 | 20,688 | 2.1% |
| Maintenance | $1,725,334 | 1,757,147 | 31,813 | 1.8% |
| Billing & Collecting | $2,107,836 | 1,978,917 | (128,919) | -6.1% |
| Community Relations | $127,331 | 113,237 | (14,094) | -11.1% |
| Administrative & General Expense | $2,548,053 | 2,825,788 | 277,735 | 10.9% |
| **Total OM&A Expenses** | **7,506,774** | **7,693,996** | **187,222** | **2.5%** |

## Table 4.4 - Summary OM&A Expense Variances 2008 Actual vs. 2009 Actual

| OM&A: 2008 Actual vs 2009 Actual | | | | |
|---|---|---|---|---|
| Description | 2008 Actual | 2009 Actual | Variance $ | Variance % |
| Operations | 1,018,908 | 1,057,112 | 38,203 | 3.7% |
| Maintenance | 1,757,147 | 1,723,356 | (33,790) | -1.9% |
| Billing & Collecting | 1,978,917 | 2,205,690 | 226,772 | 11.5% |
| Community Relations | 113,237 | 127,829 | 14,593 | 12.9% |
| Administrative & General Expense | 2,825,788 | 2,614,082 | (211,705) | -7.5% |
| **Total OM&A Expenses** | **7,693,996** | **7,728,069** | **34,073** | **0.4%** |

**Table 4.5 - Summary OM&A Expense Variances 2009 Actual vs. 2010 Actual**

| OM&A: 2009 Actual vs 2010 Actual | | | | |
|---|---|---|---|---|
| Description | 2009 Actual | 2010 Actual | Variance $ | Variance % |
| Operations | 1,057,112 | 1,008,391 | (48,720) | -4.6% |
| Maintenance | 1,723,356 | 1,681,173 | (42,183) | -2.4% |
| Billing & Collecting | 2,205,690 | 2,166,453 | (39,237) | -1.8% |
| Community Relations | 127,829 | 131,379 | 3,550 | 2.8% |
| Administrative & General Expense | 2,614,082 | 2,971,323 | 357,241 | 13.7% |
| **Total OM&A Expenses (Includes Special Purpose Charge)** | **7,728,069** | **7,958,720** | **230,651** | **3.0%** |
| Less Special Purpose Charge | | 376,534 | | |
| **Total Recoverable OM&A Expenses** | **7,728,069** | **7,582,186** | **145,883** | **1.9%** |

**Table 4.6 - Summary OM&A Expense Variances 2010 Actual vs. 2011 Actual**

| OM&A: 2010 Actual vs 2011 Actual | | | | |
|---|---|---|---|---|
| Description | 2010 Actual | 2011 Actual | Variance $ | Variance % |
| Operations | 1,008,391 | 1,076,343 | 67,951 | 6.7% |
| Maintenance | 1,681,173 | 1,456,583 | (224,590) | -13.4% |
| Billing & Collecting | 2,166,453 | 2,045,182 | (121,271) | -5.6% |
| Community Relations | 131,379 | 115,623 | (15,756) | -12.0% |
| Administrative & General Expense | 2,971,323 | 2,318,604 | (652,719) | -22.0% |
| **Total OM&A Expenses (Includes Special Purpose Charge)** | **7,958,720** | **7,012,336** | **(946,384)** | **-11.9%** |
| Less Special Purpose Charge | 376,534 | | | |
| **Total Recoverable OM&A Expenses** | **7,582,186** | **7,012,336** | **569,850** | **7.5%** |

**Table 4.7 - Summary OM&A Expense Variances 2011 Actual vs. 2012 Bridge**

| OM&A: 2011 Actual vs 2012 Bridge Year | | | | |
|---|---|---|---|---|
| Description | 2011 Actual | 2012 Bridge | Variance $ | Variance % |
| Operations | 1,076,343 | 1,111,298 | 34,955 | 3.2% |
| Maintenance | 1,456,583 | 1,802,869 | 346,286 | 23.8% |
| Billing & Collecting | 2,045,182 | 2,208,332 | 163,150 | 8.0% |
| Community Relations | 115,623 | 169,137 | 53,514 | 46.3% |
| Administrative & General Expense | 2,318,604 | 2,521,038 | 202,434 | 8.7% |
| **Total OM&A Expenses** | **7,012,336** | **7,812,674** | **800,338** | **11.4%** |

**Table 4.8 - Summary OM&A Expense Variances 2012 Bridge Year vs. 2013Test**

| OM&A: 2012 Bridge vs 2013 Test | | | | |
|---|---|---|---|---|
| Description | 2012 Bridge | 2013 Test | Variance $ | Variance % |
| Operations | $ 1,111,298 | $ 1,576,506 | $ 465,208 | 41.9% |
| Maintenance | $ 1,802,869 | $ 2,033,090 | $ 230,221 | 12.8% |
| Billing & Collecting | $ 2,208,332 | $ 2,863,215 | $ 654,883 | 29.7% |
| Community Relations | $ 169,137 | $ 232,777 | $ 63,640 | 37.6% |
| Administrative & General Expense | $ 2,521,038 | $ 2,498,437 | -$ 22,601 | -0.9% |
| **Total OM&A Expenses** | **$ 7,812,674** | **$ 9,204,025** | **$ 1,391,351** | **17.8%** |

The Table below sets out the OM&A cost per customer and per full time equivalent employee.

**Table 4.9 - OM&A per Customer and FTE**

| | Last Rebasing Year (2008 Board-Approved) | Last Rebasing Year (2008 Actuals) | 2009 Actuals | 2010 Actuals | 2011 Actuals | 2012 Bridge Year | 2013 Test Year |
|---|---|---|---|---|---|---|---|
| Reporting Basis | CGAAP | CGAAP | CGAAP | CGAAP | CGAAP | CGAAP | |
| Number of Customers | 34,960 | 36,756 | 37,038 | 37,320 | 37,747 | 38,058 | 38,548 |
| Total Recoverable OM&A from Appendix 2-I | $ 7,506,774 | $ 7,693,996 | $ 7,728,069 | $ 7,582,186 | $ 7,012,336 | $ 7,812,674 | $ 9,204,025 |
| OM&A cost per customer | $ 215 | $ 209 | $ 209 | $ 203 | $ 186 | $ 205 | $ 239 |
| Number of FTEEs | 72 | 56 | 57 | 57 | 57 | 56 | 70 |
| Customers/FTEEs | 486.43 | 659.11 | 649.79 | 658.81 | 664.11 | 678.89 | 549.19 |
| OM&A Cost per FTEE | 104,449 | 137,968 | 135,580 | 133,847 | 123,373 | 139,363 | 131,130 |

The number of customers includes the monthly average number (the sum of the total number of customers at the end of each month, divided by 12) of Residential, GS<50 and GS>50 customers as found in BPI's Load Forecast.

The number of FTEs is calculated by taking the sum of the number of employees that work directly for BPI and for 2013, the number of indirect employees who provide services with the Shared Services Agreement (SSA) between BPI and the City of Brantford (the City). BPI notes that as discussed further in Exhibit 4, Tab 2, Schedule 5, below, the 2008 Board Approved amounts include estimates of FTE and salary and wages for shared services. These are illustrative numbers, calculated based on SSA billings and the best information available to BPI in 2008. Except for those functions that were transferred to BPI on April 1, 2012 that were shared services, BPI has not included illustrative staffing and compensation analysis for other shared services for 2009 through to 2012. The service provider's staffing resources that delivered those remaining services varied depending upon the service provider's operating activities at a given time and are not specifically identifiable. As well, the amount of time that the service provider's resources spent delivering services during that time period is not known. As a result, the 2008 Actual to 2012 Bridge Year compensation levels for those resources are indeterminable and have not been included in Table 4.28 (Appendix 2-K: Employee Costs) or in the compensation analysis.

With the renegotiated SSA effective January 1, 2013 and revised costing methodology, BPI has better information about resource inputs to services purchased from its affiliate, the City, and has included that information in the analysis of head count and compensation in 2013.

However, these FTE and compensation amounts are illustrative calculations, as it is early in the 4 year term of this renegotiated SSA.

Although employees in the CDM department are included in the FTE count, their actual costs are not being recovered through distribution rates.

Detailed information with respect to OM&A costs, arranged by USoA account, is provided in Exhibit 4, Tab 2, Schedule 3. Detailed information with respect to OM&A variances, arranged by USoA account, is provided in Exhibit 4, Tab 2, Schedule 4.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of distribution revenue for distributor's with distribution revenue exceeding $10 million.

The materiality threshold for BPI based on a Distribution Revenue Requirement of $17,864,601 is $89,323. To ensure a thorough analysis, all variances greater than $70,000 have been provided with details.

**Table 4.10 - Materiality Threshold**

| Description | 2008 Board Approved | 2008 Actuals | 2009 Actuals | 2010 Actuals | 2011 Actuals | 2012 Bridge Year CGAAP) | 2013 Test Year (CGAAP) |
|---|---|---|---|---|---|---|---|
| Distribution Revenue Requirement | $ 16,879,874 | $ 16,492,164 | $ 16,169,057 | $ 16,544,331 | $ 16,259,794 | $ 16,260,626 | $ 17,864,601 |
| Materiality - 0.5% | $ 84,399 | $ 82,461 | $ 80,845 | $ 82,722 | $ 81,299 | $ 81,303 | $ 89,323 |

## OM&A COSTS

OM&A costs in this Exhibit represent BPI's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to BPI's distribution system, and meeting the requirements of the Board's Standard Supply Service Code and Retail Settlement Code.

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

### OM&A Budgeting Process

The operating budget is prepared annually, beginning with Department heads putting forth operational requests which are reviewed by the Senior Leadership Team (SLT). Overall reasonableness checks are achieved by performing yearly comparisons to prior year actuals, current year budget and projections to the levels proposed in the requested new budget. If approved, the costs are incorporated into the budget. Although the focus of the operational budget is the immediate fiscal year, the requests must be consistent with the financial parameters expected over a five year period. Once the SLT has concluded the budget is acceptable, the final steps in the budget process are that the proposed budget is submitted to the BPI Board for approval and subject to their approval, it is submitted to the Brantford Energy Corporation (BEC) Board (shareholder of BPI) for final approval.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

### Regulatory Costs

Regulatory costs as indicated in the variance analysis are presented in Table 4.11.

Regulatory costs for completing this Cost-of-Service Rate Application, amounting to $268,000, include BPI's consulting costs as well as anticipated Board and Intervenor expenses. These costs have been spread equally over a four year period beginning with the 2013 Test Year. The costs that have been included are indicated below:

**Table 4.11 - Regulatory Costs**

| | Regulatory Cost Category | USoA Account | USoA Account Balance | Ongoing or One-time Cost [1] | Last Rebasing Year (2008 Board Approved) | Most Current Actuals Year 2011 | 2012 Bridge Year | Annual % Change | 2013 Test Year | Annual % Change |
|---|---|---|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) = [(G)-(F)]/(F) | (I) | (J) = [(I)-(G)]/(G) |
| 1 | OEB Annual Assessment | 5655 | | On-Going | $ 100,000 | $ 104,380 | $ 108,000 | 3.47% | $ 108,000 | 0.00% |
| 2 | OEB Section 30 Costs (Applicant-originated) | 5655 | | One-Time | $ 10,000 | $ - | $ - | | | |
| 3 | OEB Section 30 Costs (OEB-initiated) | 5655 | | One-Time | $ 5,000 | $ - | $ - | | $ 10,000 | |
| 4 | Expert Witness costs for regulatory matters | 5655 | | One-Time | $ 10,000 | $ - | $ - | | | |
| 5 | Legal costs for regulatory matters | 5630 | | One-Time | $ 45,000 | $ 8,479 | $ 10,000 | 17.94% | $ 29,750 | 197.50% |
| 6 | Consultants' costs for regulatory matters | 5655 | | One-Time | $ 50,000 | $ 9,000 | $ 10,000 | 11.11% | $ 29,750 | 197.50% |
| 7 | Operating expenses associated with staff resources allocated to regulatory matters | 5655 | | On-Going | $ 274,099 | $ 217,863 | $ 210,004 | -3.61% | $ 283,016 | 34.77% |
| 8 | Operating expenses associated with other resources allocated to regulatory matters [1] | 5655 | | On-Going | $ 5,000 | $ 20,799 | $ 27,722 | 33.28% | $ 21,108 | -23.86% |
| 9 | Other regulatory agency fees or assessments (ESA) | 5655 | | On-Going | $ 20,000 | $ 16,013 | $ 16,400 | 2.42% | $ 19,000 | 15.85% |
| 10 | Any other costs for regulatory matters (courier fees, communications company) | 5655 | | On-Going | $ - | $ 534 | $ 7,000 | 1212.02% | | -100.00% |
| 11 | Intervenor costs | 5655 | | One-Time | $ - | $ 5,498 | $ 7,500 | 36.41% | $ 7,500 | 0.00% |
| 12 | Sub-total - Ongoing Costs [3] | | $ - | | $ 399,099 | $ 359,589 | $ 369,126 | 2.65% | $ 431,124 | 16.80% |
| 13 | Sub-total - One-time Costs [4] | | $ - | | $ 120,000 | $ 22,977 | $ 27,500 | 19.69% | $ 77,000 | 180.00% |
| 14 | Total | | $ - | | $ 519,099 | $ 382,566 | $ 396,626 | 3.68% | $ 508,124 | 28.11% |

The one-time regulatory costs included in the Bridge and Test year are in Table 4.12 below.

**Table 4.12 - One-time Regulatory Costs**

| | | Historical Year(s) | 2012 Bridge Year | 2013 Test Year |
|---|---|---|---|---|
| 4 | Expert Witness costs for regulatory matters | | $ - | $ - |
| 6 | Consultants' costs for regulatory matters | | $ 10,000 | $ 29,750 |
| 7 | Operating expenses associated with staff resources allocated to regulatory matters | | $ - | $ - |
| 8 | Operating expenses associated with other resources allocated to regulatory matters [1] | | $ - | $ - |
| 11 | Intervenor costs | | $ 7,500 | $ 7,500 |

**One-Time Cost (non-regulatory related)**

BPI has another non-regulatory one-time cost in the 2012 Bridge Year that is not included in the tables and discussion above.

The only one-time, non-regulatory related cost in the 2012 Bridge Year was legal fees in the amount of $58,501. These legal fees were related to the restructuring that took place on April 1st, 2012.

**Low Income Assistance Program (LEAP)**

BPI has included $20,910 of expense for the Low Income Assistance Program (LEAP) under Community Relations (account 5410). This amount is based on 0.12% of the 2013 Test Year Revenue Requirement, rounded. BPI notes that the amount allocated to LEAP may need to be adjusted when its 2013 revenue requirement is finalized.

**Charitable Contributions**

BPI has not included any charitable donations in OM&A expenses for 2013.

**Green Energy Act**

As discussed in Exhibit 2 of this Cost-of-Service Rate Application in relation to BPI's Green Energy Act Plan, BPI does not anticipate OM&A expenses in relation to its plan. BPI has included some operating expenses related to the Green Energy Act incurred in a prior period Deferral and Variance Account 1532 Please refer to Exhibit 9, Tab 2, Schedule 1 for more details.

## Inflation in 2012 Bridge and 2013 Test Year

The 2012 Bridge Year forecast is based on actual expenses as of June 30, 2012 plus expected expenditures for the remaining 6 months. No inflation has been applied to the expected expenditures except in cases where it is a known amount, such as increases to salaries and wages for staff according to employment and collective agreements. In this case, the anticipated economic adjustments are applied. In the 2013 Test Year, expenses have been budgeted based on existing costs and increases only if known.

## DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES

The following section discussed BPI's various departmental and corporate activities. In 2012, BPI underwent a significant organizational restructuring that saw the transfer of employees from the City to BPI. That restructuring and its impacts on OM&A are discussed greater detail in Tab 2, Schedule 3 of this Exhibit. BPI also purchases certain services from the City under a SSA that has been renegotiated in 2013. The details of these affiliate transactions are also discussed in greater detail in Tab 2 Schedule 6 to this Exhibit.

### Operations and Maintenance Department

The expenses for this department include all costs relating to the operation (5000-5096) and maintenance (5105-5195) of BPI's electrical system. This includes both direct labour costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering and Stores. BPI's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions.

BPI's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with BPI's capital project work so that where maintenance programs have identified matters which require capital investments, BPI may adjust its capital spending priorities to address those matters, facilitate the efficient delivery of power with to all BPI customers, and maintain an electrical distribution system on a 24/7 schedule year round. Activities include:

**Predictive Maintenance:** Predictive maintenance activities involve the nondestructive testing of elements of BPI's distribution system.

**Preventative Maintenance:** Preventative maintenance activities involve the inspection of and repairs to BPI's transformer station, buildings, PCB Storage facility, and electrical distribution system. This may include replacement of equipment and plant that is very near the end of its life.

**Emergency Maintenance:** Emergency maintenance activities include unexpected repairs to the electrical distribution system that must be addressed immediately.

**Service Work:** This includes service disconnections and reconnections by BPI for customers of all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority (“ESA”) inspection for service upgrades; and changes to service locations.

**Construction:** This includes the construction of expansions and upgrades to BPI’s distribution system.

**Stores:** Stores area is accountable for managing the procurement, control, and movement of materials within BPI’s service centre.

**Administration:** The management and implementation of the department’s annual work plans and budgets as well as establishing new and revising existing guidelines, procedures and maintenance standards.

**Priorities for 2013 are:**

- Upgrade feeders along Powerline Road (Construction);
- Complete inspection and testing for Asset Management program (Predictive and Preventative Maintenance);
- Complete high voltage switch maintenance (Preventative Maintenance);
- Complete the review of all safe work procedures for the department (Administration); and
- Support the organization in the development and completion of the Cost-of-Service Rate Application (Administration).

**Metering and Settlement Department**

BPI’s Metering and Settlement Department (M&S) supplies all revenue meters for approximately 38,000 customers. It is required to provide data to other internal & external departments for various filings and reports. Internal reporting includes the Regulatory, Finance and Customer Service departments. External includes Measurement Canada, Customer or third parties and the IESO. Some of the key functions performed by the M&S department are listed below:

**IESO Invoices:** M&S validates the monthly IESO Invoice and processes any disputes with the IESO relative to meter data and settlement;

**Smart Meters:** M&S manages the health of the smart meter data and smart meters;

**Installation of New Meters:** M&S manages the inventory of in-service and spare smart, conventional with demand, interval with demand and wholesale meters. This includes ensuring electricity meters meet the Measurement Canada requirements;

**Meter and Meter Installation Maintenance:** M&S manages the maintenance of the in-service meters and metering installations addressing issues related to meter communication and damages due to natural and man-made causes;

**Meter Disputes**: M&S provides meter data to customers, Customer Services and/or Measurement Canada in the event of a dispute over energy used and/or billed for;

**Electricity Marketplace Monitoring Application (EMMA):** M&S regularly reports to Measurement Canada on the electric meter population and metering installations.

**Priorities for 2013 are:**

- Meeting customer requests for data, reports or interval metered service;
- Meeting Customer Service Department’s timelines for bill calculation and creation;
- Review of applicable health and safety related work procedures;
- Keeping staff current with changes to statutory codes and requirements;
- Updating internal work procedures as required; and
- Complete 2013 pre-sample testing for Measurement Canada S-S-06 sampling inspection testing.

**Engineering and Construction Department**

BPI's Engineering and Construction department is responsible for Distribution system planning, design and construction of electrical plant in line with the requirements of Ont. Reg. 22/04, development of design standards, specifications and equipment approvals and coordinating annual ESA audits and due diligence inspections (DDIs). The department provides engineering support for servicing to customers, distribution system automation and SCADA, expansions including new sub-division and townhome developments, rebuild and conversion projects, distributed generation connection under the FIT program, capital planning and the execution of capital projects, development of asset management program, automated mapping and facilities management of electrical systems, and management of third party attachment permits.

Engineering and Construction undertakes short term and long term distribution system planning activities, system automation plans and system enhancements to improve system availability, voltage regulation and reliability of supply.

The department coordinates provision of service connections to residential, commercial and industrial customers in coordination with Metering and Operations. It also oversees the electrical design and installation for new residential developments in subdivisions and townhomes and relocation of our electrical plant to accommodate City road widening projects in coordination with the Operations department.

Compliance with Ontario Electrical Distribution Safety Regulation 22/04 is a permanent and ongoing obligation of all LDCs. BPI's Engineering and Construction coordinates all activities related to compliance with O.Reg.22/04 including the annual audit, declaration of compliance and Due Diligence Inspections by ESA (DDI) together with Operations and Metering.

The department carries out all design and construction activities, develops and maintains approved standards, specification and plans of the distribution system and provides inspection and tracking during the construction phase through until commissioning.

Development of a fully operational Asset Management Program in BPI is a long-term project undertaken by the Engineering and Construction department in consultation with other departments within BPI, to develop a condition based risk model for distribution assets through an integrated program of business processes and technologies and in support of the Cost-of-Service Rate Application to the Board.

The Engineering and Construction department prepares the 5-year capital plan and the annual capital budget in support of the Cost-of-Service Rate Application with the Board in coordination with other departments within BPI.

Mapping of electrical systems is critical for maintaining the distribution network, monitoring assets health and performance as well as providing timely information for carrying out such activities as asset management, troubleshooting system problems, assisting in utility locating services for excavations and for design and construction activities including new capital projects and customer connections. BPI's Engineering and Construction Department undertakes this through the implementation and maintenance of the Geographic Information System (GIS) software and asset database.

The department coordinates all engineering aspects of the connection process for FIT distributed generators to the distribution system. This includes processing applications, connection and cost agreements with proponents, coordination with Operations and Metering and construction verification activities for pre- and post- connection and commissioning. Coordination is also done with Hydro One, OPA and/or downstream utilities as needed, till DG connection is complete.

BPI's Engineering and Construction department implements and manages the SCADA (Supervisory Control and Data Acquisition) system. SCADA monitors the health of the distribution network at critical locations and tracks feeder level events associated with faults, loading and planned outages. It also assists Operations with troubleshooting and maintenance activities.

The department manages permit requests from third parties, such as Rogers, Bell, Brantford Hydro and the City who may require the use of BPI poles for attaching their own equipment. Each permit request is reviewed in coordination with Operations and any identified make-ready work is timely undertaken to facilitate third-party attachments.

**Priorities for 2013 are:**

- Implementation of ESA Regulation 22/04;
- Asset Management Program;
- Powerline Feeder rebuild;
- Distributed generation connections under the FIT program; and
- Voltage regulation study and installation of capacitor line banks on feeders.

**Customer Services Department**

BPI's Customer Service group is responsible for the customer care activities for approximately 38,000 customers in BPI's service area. These activities include billing, setting up accounts, arranging the proper and safe installation and removal of services, collection of accounts and other customer care functions. The Department is also responsible for settling with electricity retailers and embedded electricity generators operating within BPI's distribution service territory.

**Priorities for 2013 are:**

- Business process review from Meter to Cash register;
- Complete implementation of split bills;
- Ensure BPI achieves minimum compliance with Board standards;
- Develop new CS performance metrics and establish management reporting systems;
- Develop BPI capacity for e-billing/bill printing services;
- Evaluate business case for lock box payment handling; and
- Acquire and implement an Interactive Voice Response/Call Centre System.

**Conservation and Demand Management (CDM) Department**

BPI is responsible for the implementation and marketing of energy savings education and conservation programs to residential, commercial and industrial sectors in the City in partnership with the Ontario Power Authority (OPA).

The OPA designed, "saveONenergy" programs are available to assist electricity distribution utilities in meeting their Conservation & Demand Management (CDM) targets provided by the Board and mandated by Ontario's Ministry of Energy pursuant to the *Green Energy and Green Economy Act, 2009*. Meeting CDM targets is a condition of BPI's distribution license. BPI notes that costs related to Conservation and Demand Management are not recovered through distribution rates.

**Priorities for 2013 are:**

- Launch "PeaksaverPlus" to meet target;
- Push Residential "saveONenergy" conservation programs through customer engagement events (in-store presence, community events, etc) and increased marketing efforts to meet target;
- Engage Industrial customers with regards to potential "Demand Response 3" contracts to meet target; and
- Engage Commercial and Industrial customers to move beyond lighting projects into deeper conservation projects to meet target.

**Finance Support Department**

The Finance Support Department (Finance) provides direction and oversight of accounting and financial services to ensure compliance with generally accepted accounting principles, requirements for the federal and provincial Income Tax Acts and compliance with the Board's Accounting Procedures Handbook and related direction. In addition, the Finance department develops strategies and manages BPI's financing program and related portfolio of third party credit facilities.

**Priorities for 2013 are:**

- Cost-of-Service Rate Application support;
- Transition to new actuaries;
- Audit services RFP and possible transition;
- 2012 year-end;
- Enhanced 2013 budget process; and
- Strategic plan development support.

**Regulatory and Administration Department**

BPI interfaces with the Board on administration of routine filings, distribution rate and other applications and policy development that the Board undertakes. The Regulatory staff monitors Board policy developments and code amendments and delivers plans to implement new requirements. Ensuring compliance with Board codes and guidelines is also this department's responsibility. This involves reviewing Board codes and subsequently providing training and conducting audits to reach compliance may also be required.

Governance and administration activities include coordination and management of monthly BPI board meetings, preparing BPI board packages and minutes are required as is providing support to the BPI board members and writing reports on behalf of the BPI board. Governance activities include the development and management of corporate policies and agreements.

This group also manages corporate communications including, among other matters, management of BPI's website.

**Priorities for 2013 are:**

- Cost-of-Service Rate Application;
- Steering the Systems Integration Study;
- Ongoing redevelopment of BPI's website including facilities for e-billing and web-based payment services;
- Development of BPI corporate policies following transfer of functions and employees from the City; and
- Strategic plan development support.

# OM&A DETAILED COSTS TABLES

BPI's expenses at a USoA account level from 2008 to 2011 including the 2012 Bridge Year and 2013 Test Year forecasts are set out in Tables 4.13 to 4.17, below. Following these tables is a discussion of cost drivers that have impacted BPI's expenses during that time period.

## Table 4.13 - Detailed Account by Account Operation Expenses

| Account Description | Last Rebasing Year (2008 Actuals) | 2009 Actual | 2010 Actual | 2011 Actual[2] | Bridge Year 2012[3] | Test Year 2013 |
|---|---|---|---|---|---|---|
| *Reporting Basis* | CGAAP | CGAAP | CGAAP | CGAAP | CGAAP | CGAAP |
| ***Operations*** | | | | | | |
| 5005 Operation Supervision and Engineering | $ 311,749 | $ 332,926 | $ 335,123 | $ 327,414 | $ 226,223 | $ 273,250 |
| 5010 Load Dispatching | $ 38,989 | $ 35,700 | $ 49,739 | $ 31,918 | $ 45,927 | $ 114,745 |
| 5012 Station Buildings and Fixtures Expense | $ 40,428 | $ 33,982 | $ 29,812 | $ 25,755 | $ 29,252 | $ 29,322 |
| 5014 Transformer Station Equipment - Operation Labour | $ 6,002 | $ 5,596 | $ 7,009 | $ 15,354 | $ 7,906 | $ 24,787 |
| 5015 Transformer Station Equipment - Operation Supplies and Expenses | $ 77,928 | $ 67,308 | $ 72,587 | $ 96,171 | $ 75,365 | $ 102,609 |
| 5016 Distribution Station Equipment - Operation Labour | $ 2,481 | $ 2,387 | $ 1,277 | $ 4,208 | $ 1,743 | $ 1,962 |
| 5017 Distribution Station Equipment - Operation Supplies and Expenses | $ 3,421 | $ 1,512 | $ 1,134 | $ 1,155 | $ 400 | $ 520 |
| 5020 Overhead Distribution Lines and Feeders - Operation Labour | $ 1,222 | $ 2,523 | $ 1,771 | $ 1,928 | $ 985 | $ 1,962 |
| 5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses | $ 720 | $ 6,293 | $ 6,026 | $ 1,976 | $ 10,893 | $ 12,752 |
| 5030 Overhead Sub-transmission Feeders - Operation | $ - | $ - | $ - | $ - | $ - | $ - |
| 5035 Overhead Distribution Transformers - Operation | $ 1,044 | $ 8,986 | $ 9,393 | $ 3,868 | $ 2,989 | $ 5,154 |
| 5040 Underground Distribution Lines and Feeders - Operation Labour | $ 1,137 | $ 139 | $ 1,671 | $ 1,178 | $ 670 | $ - |
| 5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses | $ 11,204 | $ 5,625 | $ 10,635 | $ 6,267 | $ 9,508 | $ 11,990 |
| 5050 Underground Sub-transmission Feeders - Operation | $ - | $ - | $ - | $ - | $ - | $ - |
| 5055 Underground Distribution Transformers - Operation | $ 1,830 | $ 1,387 | $ 1,736 | $ 685 | $ 665 | $ - |
| 5060 Street Lighting and Signal System Expense | $ - | $ - | $ - | $ - | $ - | $ - |
| 5065 Meter Expense | $ 305,437 | $ 285,758 | $ 265,762 | $ 363,773 | $ 464,155 | $ 593,094 |
| 5070 Customer Premises - Operation Labour | $ 897 | $ 315 | $ 334 | $ 461 | $ 710 | $ 5,292 |
| 5075 Customer Premises - Operation Materials and Expenses | $ - | $ - | $ - | $ - | $ - | $ - |
| 5085 Miscellaneous Distribution Expenses | $ 214,419 | $ 253,078 | $ 186,167 | $ 182,823 | $ 221,832 | $ 329,209 |
| 5090 Underground Distribution Lines and Feeders - Rental Paid | $ - | $ - | $ - | $ - | $ - | $ - |
| 5095 Overhead Distribution Lines and Feeders - Rental Paid | $ - | $ 13,596 | $ 19,983 | $ 6,869 | $ 7,343 | $ 25,403 |
| 5096 Other Rent | $ - | $ - | $ 8,233 | $ 4,540 | $ 4,732 | $ 44,455 |
| **Total - Operations** | $ 1,018,908 | $ 1,057,112 | $ 1,008,391 | $ 1,076,343 | $ 1,111,298 | $ 1,576,506 |

## Table 4.14 - Detailed Account by Account Maintenance Expenses

| Account Description | Last Rebasing Year (2008 Actuals) | 2009 Actual | 2010 Actual | 2011 Actual[2] | Bridge Year 2012[3] | Test Year 2013 |
|---|---|---|---|---|---|---|
| ***Maintenance*** | | | | | | |
| 5105 Maintenance Supervision and Engineering | $ 301,446 | $ 304,849 | $ 325,801 | $ 307,486 | $ 432,478 | $ 499,599 |
| 5110 Maintenance of Buildings and Fixtures - Distribution Stations | $ - | $ 431 | $ 1,031 | $ 1,892 | $ 1,559 | $ 2,158 |
| 5112 Maintenance of Transformer Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 5114 Maintenance of Distribution Station Equipment | $ 7,164 | $ 9,409 | $ 10,704 | $ 5,684 | $ 6,747 | $ 9,805 |
| 5120 Maintenance of Poles, Towers and Fixtures | $ 182,780 | $ 135,624 | $ 57,113 | $ 44,139 | $ 32,442 | $ 75,414 |
| 5125 Maintenance of Overhead Conductors and Devices | $ 116,671 | $ 128,912 | $ 109,023 | $ 196,827 | $ 184,573 | $ 242,022 |
| 5130 Maintenance of Overhead Services | $ 230,266 | $ 200,498 | $ 229,757 | $ 218,602 | $ 192,135 | $ 247,604 |
| 5135 Overhead Distribution Lines and Feeders - Right of Way | $ 443,359 | $ 399,183 | $ 396,203 | $ 348,542 | $ 415,898 | $ 499,535 |
| 5145 Maintenance of Underground Conduit | $ 43,295 | $ 75,395 | $ 38,898 | $ 54,614 | $ 52,661 | $ 56,902 |
| 5150 Maintenance of Underground Conductors and Devices | $ 78,960 | $ 138,560 | $ 89,626 | $ 71,835 | $ 70,158 | $ 82,311 |
| 5155 Maintenance of Underground Services | $ 210,769 | $ 221,815 | $ 143,095 | $ 138,372 | $ 109,059 | $ 124,877 |
| 5160 Maintenance of Line Transformers | $ 142,265 | $ 108,654 | $ 279,921 | $ 68,591 | $ 305,006 | $ 192,863 |
| 5165 Maintenance of Street Lighting and Signal Systems | $ - | $ - | $ - | $ - | $ - | $ - |
| 5170 Sentinel Lights - Labour | $ - | $ - | $ - | $ - | $ - | $ - |
| 5172 Sentinel Lights - Materials and Expenses | $ - | $ - | $ - | $ - | $ - | $ - |
| 5175 Maintenance of Meters | $ 171 | $ 26 | $ - | $ - | $ 153 | $ - |
| 5178 Customer Installations Expenses - Leased Property | $ - | $ - | $ - | $ - | $ - | $ - |
| 5195 Maintenance of Other Installations on Customer Premises | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total - Maintenance** | $ 1,757,147 | $ 1,723,356 | $ 1,681,173 | $ 1,456,583 | $ 1,802,869 | $ 2,033,090 |

## Table 4.15 - Detailed Account by Account Billing & Collecting Expenses

| Account | Description | Last Rebasing Year (2008 Actuals) | 2009 Actual | 2010 Actual | 2011 Actual[2] | Bridge Year 2012[3] | Test Year 2013 |
|---|---|---|---|---|---|---|---|
| ***Billing and Collecting*** | | | | | | | |
| 5305 | Supervision | $ 167,397 | $ 175,292 | $ 181,121 | $ 161,326 | $ 223,136 | $ 292,372 |
| 5310 | Meter Reading Expense | $ 409,719 | $ 440,325 | $ 402,412 | $ 354,422 | $ 274,993 | $ 240,556 |
| 5315 | Customer Billing | $ 517,916 | $ 542,936 | $ 555,894 | $ 495,101 | $ 542,425 | $ 964,616 |
| 5320 | Collecting | $ 334,793 | $ 350,585 | $ 362,242 | $ 322,653 | $ 359,916 | $ 536,496 |
| 5325 | Collecting - Cash Over and Short | $ - | $ - | $ - | $ - | $ - | $ - |
| 5330 | Collection Charges | $ 282 | $ 548 | $ 454 | $ 833 | $ 1,000 | $ 500 |
| 5335 | Bad Debt Expense | $ 130,318 | $ 257,772 | $ 211,527 | $ 307,532 | $ 300,000 | $ 306,000 |
| 5340 | Miscellaneous Customer Accounts Expenses | $ 418,492 | $ 438,231 | $ 452,803 | $ 403,316 | $ 506,862 | $ 522,675 |
| **Total - Billing and Collecting** | | $ 1,978,917 | $ 2,205,690 | $ 2,166,453 | $ 2,045,182 | $ 2,208,332 | $ 2,863,215 |

## Table 4.16 - Detailed Account by Account Community Relations Expenses

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

## Table 4.17 - Detailed Account by Account General & Administrative Expenses

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

## Summary of Cost Drivers

Because the organizational restructuring that took place over the period of 2011 and 2013 has impacted BPI's OM&A costs, BPI has provided a detailed description of those organizational changes below with a high level indication of where those changes have impacted its expenses. The more detailed discussions of cost drivers, materiality and variance analysis at the USoA account level and compensation-related costs follow this overview of organizational changes.

## Organizational Restructuring – 2012 to 2013

Prior to 2012, BPI had one employee – its Chief Executive Officer – and purchased all other services from its affiliate, the City, under a SSA. In 2012, BPI underwent a corporate reorganization that saw the transfer of all City employees that provided services exclusively to BPI from the City to BPI on April 1, 2012. These functions transferred to BPI included:

- Operations and Maintenance;
- Engineering and Construction;
- Metering;
- Settlement;
- Conservation and Demand Management;
- Regulatory; and
- Administration.

Prior to April 1, 2012, BPI had purchased a variety of other services from the City that were transferred to BPI on April 1, 2012. These previously shared services included:

- Customer Services;
- Utilities Accounting (now "Finance");
- Inventory Management; and
- Dispatch.

Those services delivered by the City included both service activities and management of those services. For those services where senior and/or front-line management staff was not transferred to BPI, further organizational restructuring within BPI was required to incorporate those functions within BPI's management structure. Specifically, Customer Services, Conservation and Demand Management and Finance were incorporated into the portfolio managed by the BPI's Chief Financial Officer (CFO) while Inventory Management and Dispatch were included in BPI's Operations and Maintenance Department.

The officers of BPI – the CFO and the Board Secretary, who is also BPI's Director of Regulatory Affairs, had previously been shared among the Energy Group of Companies including Brantford Energy Corporation (BEC), a holding company; Brantford Hydro Inc. (BHI), a retail affiliate; and Brantford Generation Inc. (BGH), a generation affiliate.

The BPI organizational chart that resulted from the transfer of employees is included in Exhibit 1 Tab 1 Schedule 12.

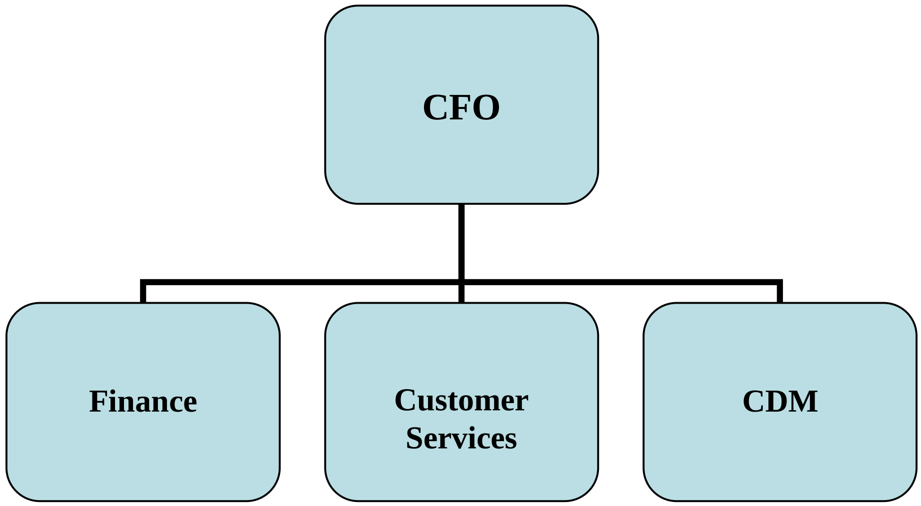
Each of these corporate restructuring changes is discussed in greater detail below in relation to the corporate portfolios that they now belong to.

**The Finance Portfolio**

The present Finance portfolio headed by the CFO comprises:

- Finance;
- Customer Services; and
- Conservation and Demand Management.

**Chart 4-1 - The Finance Portfolio – 2012**




Prior to 2012, BPI's CFO was an employee of the City and shared among the Energy Group of Companies as CFO to BPI, BHI, BGI and BEC. In addition to the CFO role, this position was also the Chief Executive Officer of BHI and BGI. On January 1, 2012, this position was transferred to BPI and assumed responsibility for an expanded portfolio within BPI to include Customer Services on April 1, 2012 and Conservation and Demand Management on October 1, 2012. While BPI continues to purchase the financial services of accounts payables processing and payroll from the City, the CFO assumed responsibility for other financial services such as banking services that had been previously provided by the City under an SSA. To August 2012, the CFO provided transitional management assistance on a fee for services basis to the retail (BHI) and generation (BGI) affiliates while those companies undertook to recruit a replacement.

**BPI Finance Department**

Prior to April 1, 2012, the City's Utilities Accounting Division provided shared services to all of the companies in Brantford's Energy Group. With a headcount of 4, an estimated 60% of time was spent on BPI activities comprising an FTE headcount of 2.4. On April 1, 2012, two of four employees were transferred from the City's Utilities Accounting Division to BPI's Finance

Department resulting in a resourcing deficit of .6 FTE. Along with new responsibilities such as banking services previously provided by the City, the transfer of employees and separation of activities caused significant transitional work for BPI's new Finance Department that is still ongoing as BPI develops fully independent budgeting, accounting including restructuring of the chart of accounts and reallocation practices and financial reporting systems. The combination of the resource deficit at transfer, new accountabilities and ongoing transitional activities has created the need for an additional staff resource in the Finance Department. Starting in 2013, the costs of the Finance Department are treated as indirect costs and allocated to various other BPI functions; that is, those costs are not booked to a specific USoA account but are allocated over all OM&A accounts.

**BPI Customer Services Department**

On April 1, 2012, the City's Utilities Customer Services Division, which had previously provided billing, collections and customer care services to the City's water and wastewater utilities and BPI's electricity distribution activities, along with billing for electric water heaters and sentinel lights for BHI, was split. Customer Services activities for water and wastewater as well as BHI retail billing were retained by the City. Customer services activities for BPI's electricity distribution activities and associated resources were transferred to BPI on April 1, 2012. The City and BPI continued to issue a joint utility bill until May 6, 2013 at which time the Customer Information System was divided and separate bills for City/BHI and BPI services were issued. Due to the separation of the Customer Information Systems, the City and BPI are precluded from sharing cashiering services for the payment of customer accounts.

On April 1, 2012, an estimated 11.38 FTE Customer Services positions including vacant positions out of a total of 20 positions were transferred from the City to BPI. Ownership of the fully depreciated legacy Customer Information System was transferred from the City to BPI on January 1, 2013. The disaggregation of the integrated Customer Services function was a significant transition for this critical BPI function throughout 2012 and into 2013. The transition has required reorganization of staffing including management activities and physical space as well as changes to operating systems and business processes.

In combination, these transitional activities have negatively impacted BPI's customer services service quality indicators in 2012. As set out in Exhibit 2, Tab 3, Schedule 6 for example, BPI's telephone response statistics in 2012 were 64.7%, which is under the Board's standard of 65%. Further, BPI notes that the splitting of customer services activities between the City's water and BPI electricity customer support has not resulted in fewer customer contacts; rather the level of contact remains the same although contacts are of slightly shorter duration. An additional investment discussed later in this Exhibit in relation to cost drivers and variance analysis from 2011 to 2013 in Customer Services staffing is required to improve BPI's service quality indicator results in the future.

**The Operations Services Portfolio**

Prior to 2011, the Operational Services portfolio included Operations [5000 Series], Maintenance [5100 Series], Metering [5000 and 5100 Series], Settlement [5100 and 5300 Series] and Community Relations [5400 Series] activities. The Chief Operating Officer (COO) was responsible for the Operations Services portfolio with three management positions – the Director of Operations and Maintenance, the Director of Engineering and Construction and the Manager of Metering and Settlement, reporting to that position. The position of COO was not filled with the resignation on the incumbent at the beginning of 2011, which, as discussed below, resulted in restructuring of each of the operational areas. In all three cases, the reporting relationship of the managers in those operating areas changed from the COO to the Chief Executive Officer and each manager assumed enhanced roles at the senior management level. Changes in corporate priorities and new work requirements such as the development of BPI's Asset Management program and new activities related to the *Green Energy Act, 2009* were other factors that led to this internal reorganization. The restructuring changes are illustrated in Charts 4-2 and 4-3 below.

**Chart 4-2 – The Operations Services Portfolio - up to 2011**

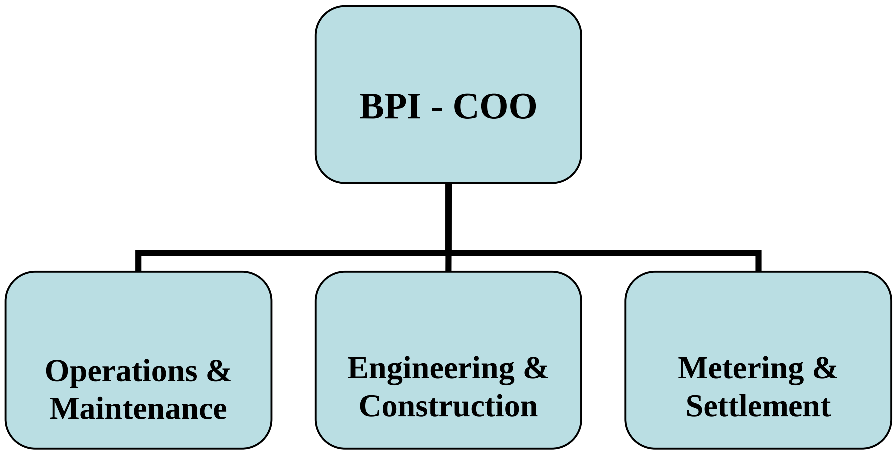
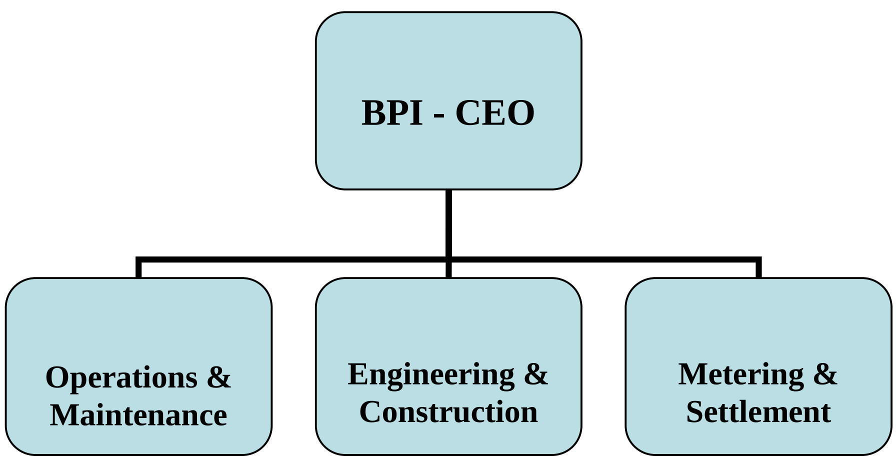


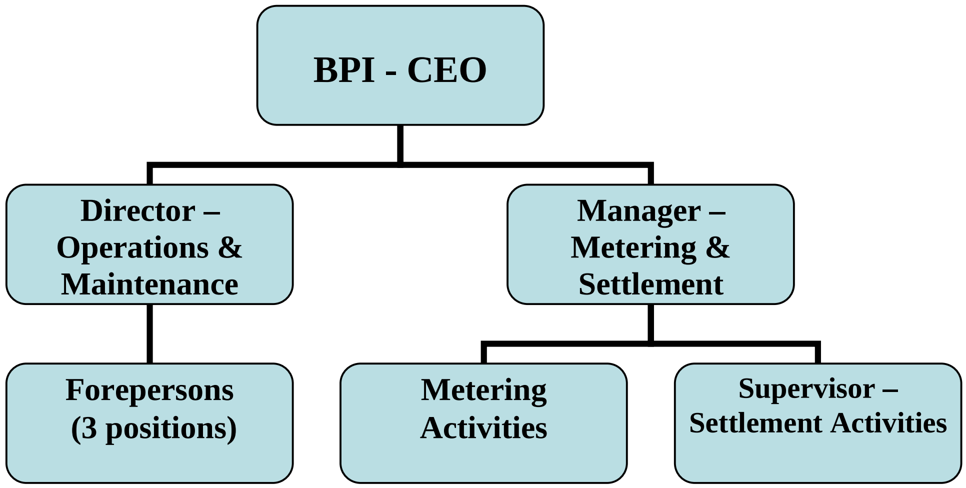

**Chart 4-3 – The Operations Services Portfolio - 2011 - 2012**




**The Operations and Energy Portfolio**

The current Operations and Energy Portfolio is an amalgamation of the former Operations and Maintenance and Metering and Settlement Departments and includes the Dispatch and Inventory Management functions transferred from the City on April 1, 2012. Changes to the Operations and Energy portfolio since April 1, 2012 are set out in Charts 4-4 and 4-5 below.

**Chart 4.4 – Operations, Metering and Settlement, Inventory Management Structures prior to April 1, 2012**



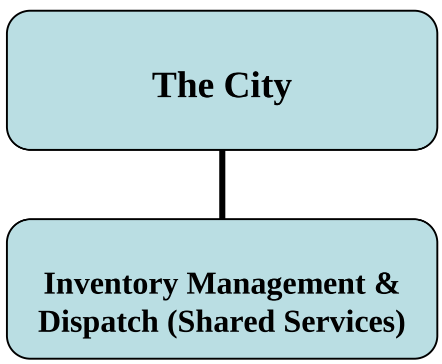
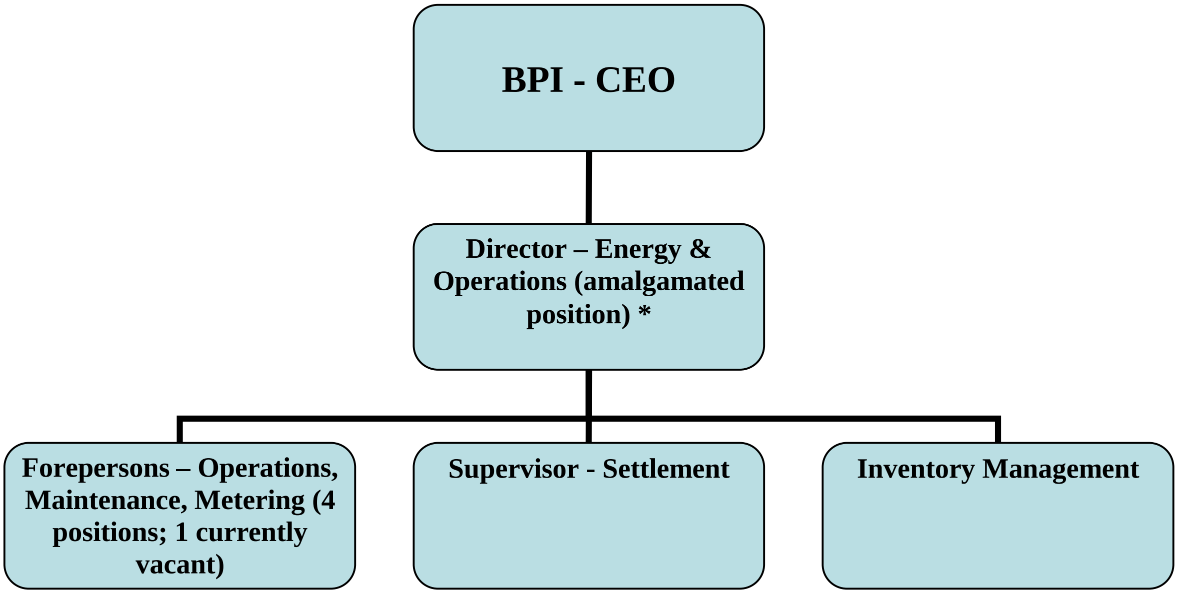



**Chart 4-5 – Operations and Energy Structure – following restructuring - January 2013**




* This position is an amalgamation of the former Director of Operations and Maintenance and Manager of Metering and Settlement.

The restructured Energy and Operations portfolio is headed by the Director of Energy and Operations, a position that has consolidated the former managerial responsibilities of the Director of Operations and Maintenance, the Manager of Metering and Settlement and a Purchasing Supervisor at the City. The latter position shared 50% of their time and costs through service fees to BPI to supervise the Dispatch and Inventory Management activities. The Director of Operations and Energy assumed the position at the end of June 2012 in order to understudy the incumbent Director of Operations who was planning to retire. The 2013 Test Year budget includes one new Operations Foreperson position to offset the expanded scope of activities for which the Director of Operations and Energy is responsible; in effect, the previous Director of Operations and Maintenance position is being replaced by a General Foreperson at lower compensation costs. This fourth foreperson position, with a specific focus on metering activities, is planned to be filled in 2013 to be responsible for the following duties:

- Preconstruction meetings, capital and engineering construction;
- Meter shop supervision;
- Meter inventory, meter specifications, meter programs, meter badge numbering;
- MicroFIT management; and
- Back-up for Underground and Overhead Foreperson.

Prior to the formal restructuring of his position in June 2012, the Director of Operations and Energy had filled the position of Manager of Metering and Settlement with an expanding scope of responsibility for smart meter implementation, conservation and demand management and MicroFIT contracts along with traditional metering and settlement activities. The expanding scope of this position caused a restructuring in mid-2011 with a non-management Settlement Officer position reclassified to a management position responsible for supervision of the Settlement Department. This reclassification caused some incremental increases in compensation costs fully realized in 2012 OM&A. This change is discussed in more detail below in the discussion of changing corporate and work priorities related to smart metering and time-of-use pricing implementation.

The two inventory management staff transferred to BPI at April 1, 2012 had previously been shared with BPI's retail affiliate, BHI. At transfer, BPI assumed 100% of the cost of those functions, an increase of 10%. As well, BPI assumed 100% of the cost of the Dispatcher transferred to BPI on April 1, 2012. However, those cost increases were offset by elimination of the service fees for the 50% supervisor.

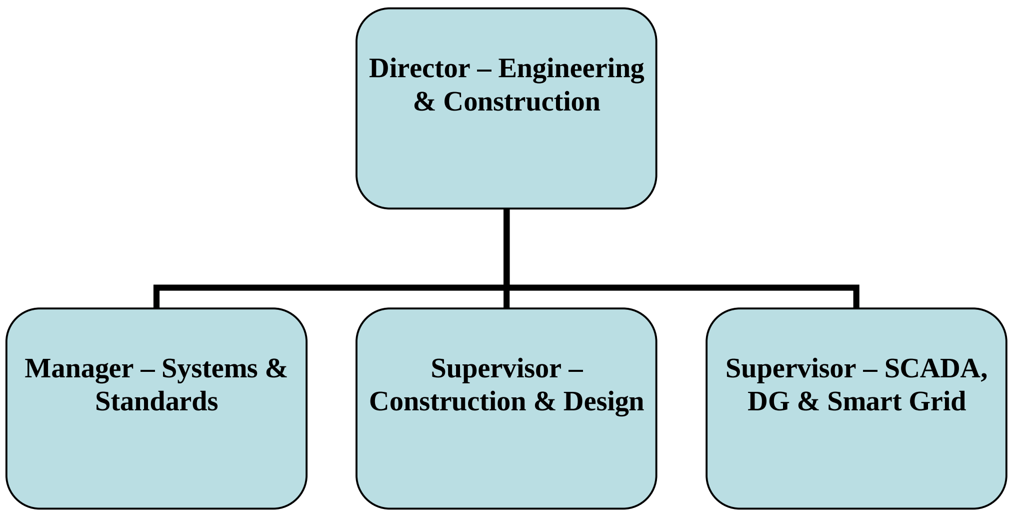
**The Engineering and Construction Portfolio**

Reorganization of the Engineering and Construction Department took effect on April 1, 2012 as employees were transferred from the City to BPI. At April 1, 2012, 9 positions were transferred. Of those 9 positions, three positions were reclassified from non-managerial positions to managerial positions causing incremental increases to compensation costs for those reclassified positions. Evolving corporate priorities that focused on developing BPI's Asset Management Program, distribution automation and load dispatching and development of BPI's SCADA system, along with enhanced focus on public and worker safety through documented standards and new responsibilities to manage FIT contracts, were the principal drivers of these restructurings. The three reclassified positions include:

- The Manager of Systems and Standards who is principally responsible for the implementation and operation of BPI's Asset Management program, CAD systems and record-keeping and standards program;
- The Supervisor of Construction and Design who is principally responsible for BPI's distribution infrastructure construction program; and
- The Supervisor of SCADA, Distributed Generation and Smart Grid who, in addition to SCADA and distribution system automation, is also responsible for managing FIT contracts and load dispatching.

The resulting management structure is set out in Chart 4-6 below.

**Chart 4-6 – The Engineering and Construction Portfolio - at April 1, 2012**




In addition to establishing the Supervisor of SCADA, Distributed Generation and Smart Grid position, an existing engineering technologist position in the Engineering and Construction Department was repurposed as an Electrical System Planner to support SCADA and load dispatch activities. Those activities were previously staffed by only one position and BPI required back-up support for these critical operational functions. This repurposed position was reclassified upwards causing an incremental increase in compensation costs. An existing employee was moved into the new position leaving the former position vacant. The engineering technologist position remains vacant and is in the 2013 Test Year budget to be filled in 2013. As a result, there is an addition to head count in the Engineering and Construction portfolio. However, once the vacancy is filled, the employee in that position will provide support to design and construction activities that are capitalized with the result that the increase in head count has only minimal impact to 2013 OM&A.

The ongoing development and implementation of BPI's Asset Management Program and distribution system automation are two changes to work priorities in the Engineering and Construction that have increased OM&A costs. In addition to the staff resource changes discussed above, both of these changing work priorities require additional software investments including maintenance costs and contracted services.

For a more detailed discussion of these cost impacts, please refer to the cost driver and variance analysis discussions for the period of 2011 to 2013 for Accounts 5010 and 5085.

**The Regulatory and Administration Portfolio**

Prior to April 1, 2012, BPI's Board Secretary (also Director of Regulatory Affairs) had been shared among Brantford's Energy Group of Companies. With the transfer of this position, BPI has absorbed 100% of the costs of this position formerly allocated among the Energy Group increasing costs to BPI. At that time, the position was reclassified from a managerial role to a Director position with a nominal incremental compensation cost increase. The reclassification of this position resulted from the evolution of this role with an expanded scope of responsibility and changing corporate priorities. These increases, however, have been offset by reductions through the elimination of an administrative position upon the incumbent's retirement in 2013.

"Growing regulatory depth and expertise" had been a BPI corporate priority in its strategic plan from 2010 to 2012. To this end, a new Regulatory Analyst position, which had been included in BPI's 2008 test year budget, was filled in July 2011. Preparatory to filling this new position, the existing Regulatory Analyst position was repurposed as a supervisory position with day-to-day management responsibility for BPI's regulatory activities. The repurposing of this position as a supervisory role was in part due to the expanding scope of activities undertaken by the Regulatory and Administration Department. As an example of this expanded scope, BPI began a comprehensive website design revision in 2012, with a design that is distinct from affiliates in the Energy group. Further work is underway to implement web-based services for customers

**Other Corporate Changes**

As part of the corporate reorganization that transferred employees from the City to BPI, BPI also assumed ownership of various information technology systems and assets (IT assets) used exclusively by BPI but owned by the City on January 1, 2013. While the transfer of IT assets has not directly increased BPI's OM&A costs, it has resulted in new functional responsibilities and a need to develop internal capacity for those responsibilities. As a result, BPI is undertaking a Systems Integration Study in 2013 to provide a roadmap to systems integration to meet a strategic objective to "leverage technology and capital to gain productivity improvements". The outcomes of the study will provide a plan for future investments – both capital and OM&A – in these systems.

With the transfer of employees on April 1, 2012, two BPI labour groups were established along with the IBEW – Power labour group. The Brantford Power Professional and Administrative Employees Association ("the Association") and CUPE Local 181 – Brantford Power were established. These labour groups had previously been part of the City's Association and CUPE groups. Like the transfer of assets, the establishment of these new labour groups has not directly impacted BPI OM&A costs. However, responsibility for negotiations and labour relations previously undertaken by the City is now shared among BPI's directors, which has also caused some of the corporate reorganization and enhancement of its Senior Leadership Team and management structure.

**Cost Drivers**

The following Table sets out the cost drivers for increases from the 2008 historical year to the 2012 forecasted Bridge Year, from the 2012 forecasted Bridge Year and the 2013 Test Year and from the 2011 historical year to the 2013 Bridge Year. Each of the major cost drivers are discussed in further detail below and variances over the materiality threshold of $70,000 are discussed in Exhibit 4, Tab 2, Schedule 4.

**Appendix 2-J**
**OM&A Cost Driver Table**

| OM&A | Last Rebasing Year (2008 Actuals) | 2009 Actuals | 2010 Actuals | 2011 Actuals | 2012 Bridge Year | 2013 Test Year |
|---|---|---|---|---|---|---|
| *Reporting Basis* | | | | | | |
| **Opening Balance** | $ 7,506,774 | $ 7,693,996 | $ 7,728,069 | $ 7,582,186 | $ 7,012,336 | $ 7,812,674 |
| Decrease in Regulatory Expense | | | (100,215) | | | |
| Restructuring - Customer Services Compensation | | | | | $ 128,085 | $ 71,100 |
| Restructuring - Customer Services, Supplies and Contracted Services | | | | | | $ 289,405 |
| Restructuring - Corporate Officers | | | | | $ 72,469 | |
| Changes to Work Priorities - Metering & Settlement Compensation, Smart Metering | | | | | $ 116,604 | |
| Changes to Work Priorities - Smart Meter Reading, Contracted Services | | | | | $ 100,382 | |
| Changes to Work Priorities - Decrease in Conventional Meter Reading Services | | | | | (79,429) | |
| Changes to Work Priorities - Distribution System Design | | | | | 70,721 | |
| Changes to Work Priorities - Maintenance of Line Transformers | | | $ 152,434 | | $ 201,671 | |
| Reconciliation of Monies Due on Retirement | | | | | $ 217,000 | |
| Restructuring - Finance Compensation | | | | | | $ 77,000 |
| Removal of 10% Mark-up where impacts are below the materiality threshold on a USoA account basis | | | | (600,000) | | |
| Change in Capitalization Policy where impacts are below materiality threshold on a USoA account basis | | | | | | $ 972,502 |
| Changes to Work Priorities - Mtce of Line Transformers | | | | | | |
| Various Expense Variances Below Materiality Threshold | $ 187,222 | 34,073 | (198,102) | $ 30,150 | (27,165) | (18,656) |
| **Closing Balance** | $ 7,693,996 | $ 7,728,069 | $ 7,582,186 | $ 7,012,336 | $ 7,812,674 | $ 9,204,025 |

As set out in Appendix 2-J, BPI's OM&A expenses overall remained relatively constant for the period of 2008 to 2010 increasing by $75,412 from the 2008 BA test year budget to the end of 2010 although there were changes among operational cost areas that are discussed in greater detail in the variance analysis at the USoA account level below.

**2008 BA to 2008 Actual Cost Drivers:**

BPI advises that due to changes in work priorities between the preparation of BPI's Cost-of-Service Rate Application (EB-2007-0098) and approval of its 2008 Operating and Capital Budgets by the BPI Board of Directors against which staff managed costs, there were changes to the amounts in specific USoA accounts.

BPI notes that in its decision on BPI's Cost-of-Service Rate Application dated July 18, 2008, the Board stated:

> *The Board Approved Controllable OM&A spending for ratemaking purposes is an envelope approach. The specific OM&A line item expenses will be managed by the Company as it sees fit. The Company will be accountable for the decisions it makes in prioritizing its spending plans within the envelope as it supports its historic spending as a basis for its proposed revenue requirement in its next rate rebasing application. (Page 10)*

Variances between the 2008 Board Approved amounts and the 2008 Actual amounts at the USoA account level are attributable to this change in work priorities. The total variance between 2008 Board Approved and 2008 Actual OM&A spending is $187,222. In the subsequent materiality and variance analysis, BPI has identified the specific amounts resulting from this difference between the 2008 Board Approved Test Year budget and the Operating Budget approved by the BPI Board of Directors.

BPI advises that the 2013 Test Year Budget and underlying trial balance were approved by the BPI Board of Directors.

**2008 Actual to 2009 Cost Drivers**

The increase in costs for the period of 2008 to 2009 is $34,073, which is attributable to changes to costs under BPI's materiality threshold.

**2009 to 2010 Cost Drivers**

In the period to 2009 to 2010, BPI experienced an overall decrease to costs in the amount of ($145,883). Two factors have influenced this change to costs:

As a result of a change to work priorities that resulted in higher than typical levels of line transformer maintenance to larger non-residential transformers in 2010 coupled with the change to BPI's transformer size standard, transformer inventory costs increased by $152,434. While labour and fleet time booked to Account 5160 also increased accordingly in 2010, BPI has attributed only the change to inventory as a cost driver as labour and trucks would have been redeployed to other activities; that is, the labour and fleet costs were not changed overall as a result of this change to work priorities. For further explanation of the change to transformer size standard, please refer to Exhibit 2, Tab 3, Schedule 2.

This increase was offset in part by a decrease of ($100,215) for external regulatory legal and consulting services (Account 5655) in that year. Higher than typical costs were booked to Account 5655 in the previous two years due to BPI proceedings before the Board including in 2008, BPI's its Cost-of-Service Rate Application and in 2009, the BCPI motion for an embedded distributor rate. In 2010, BPI did not have any significant regulatory matters before the Board and as a result, costs returned to a more typical level.

The balance of the decrease in the amount of $198,102 was due to various changes to costs below BPI's materiality threshold.

**2011 to 2013 Cost Drivers Overview**

As discussed above, the period of 2011 to 2013 saw fundamental changes to BPI's operating methods, corporate policies and organizational structure that, along with changes to work priorities like the implementation of smart metering and time-of-use pricing and distribution system automation, have impacted BPI's OM&A expenses during that time period.

The changes to OM&A from 2011 through to 2013 resulted from five main causes:

- Changes to charges from BPI's affiliate, the City; specifically, the removal of the 10 per cent mark-up on services in 2011;

- The operationalization of BPI's smart metering system and transition to time-of-use pricing in 2012 at which time costs booked to the Smart Meter Deferral and Variance Accounts were booked to regular OM&A accounts;

- The transfer to employees from the City to BPI on April 1, 2012, which in particular impacted Customer Services costs with the splitting of department in 2012 and the splitting of the customer bill in 2013;

- The transfer of corporate officers and the now Finance Department, the costs of which had previously been shared among the Energy Group of companies impacting costs in both 2012 and 2013; and

- The change to BPI's capitalization policy in 2013.

Each of these changes along with other costs drivers in those years is discussed below.

**2010 to 2011 Cost Drivers**

**Affiliate Fees and the 10 Per Cent Mark-Up**

BPI's predecessor entity, the Hydro-Electric Commission of Brantford, had purchased all operational and administrative services from the City on a service basis since the amalgamation of the City and the Public Utilities Commission of Brantford in 1996. This purchase of service arrangement remained in place up to the organizational restructuring in 2012.

As an overview of the costs related to those services, BPI notes two significant changes in this summary. Prior to 2011, the service fees paid by BPI for services purchased from the City included a 10% mark-up intended as a proxy for market pricing. The mark-up was applied to services and labour but was not applied to inventory. This mark-up was removed from service fees beginning in 2011 resulting in an estimated reduction of ($600,000) in operating costs in that year. Because the mark-up was applied to costs excluding inventory owned by BPI, in a given year, its value fluctuated depending upon the value of the base costs to which it was applied. As a result, BPI has provided an estimate of the value of the mark-up. Because the mark-up was applied to all services fees, the impacts of removing the mark-up are not attributable to specific USoA accounts but impacted all accounts in 2011.

**2011 to 2012 Cost Drivers**

A variety of factors impacted BPI's costs in 2012, which saw an increase of $800,388 in 2012 over 2011.

**Restructuring – Customer Services**

As discussed above, 11.38 Customer Services positions, some of which positions were vacant, were transferred to BPI on April 12, 2012. At that time, the compensation costs for Customer Services were separated with BPI paying directly for its employees and the remainder of Customer Services costs were shared with the City until 2013. An apparent cost increase of $128,085 is attributable to changes in revenue recognition of costs related to City water and sewer customer care services. Prior to 2013, the City paid a fee of $2.90 per customer bill per month for a bundle of customer billing and support services that included customer billing, customer collections and customer support as well as IT services including the provision of a Customer Information Services and Dispatch Services. That bundle of services was provided by three separate organizational divisions within the City – its Utility Customer Services Division, its IT Services Department and its Purchasing Department, which was responsible for the management of the Dispatch function. The revenue for that bundle of services was attributed entirely to the budget of the Utility Customer Services division with the result that the residual costs billed to BPI for customer services were artificially reduced. In 2012, the Dispatch function was transferred to BPI and with the transfer of ownership of the Customer Information System, BPI pays for that portion of costs directly attributable to BPI. Customer Services staffing costs only were unbundled in 2012 as the City and BPI continued to issue a joint bill and share related costs until the bills were unbundled in 2013. As a result, the impact of this revenue recognition effect was attributed to Customer Services staffing costs in 2012.

**Restructuring – Transfer of Corporate Officers**

Prior to 2012, BPI's CFO was the Chief Financial Officer to the other companies in BEC as well the CEO to BHI and BGI. In 2011, the CFO had charged 49 per cent of his time to BPI. At January 1, 2012, the incumbent CFO was transferred from the City to BPI.

During this transitional period, the CFO continued to provide managerial assistance to BHI and BGI as a successor was recruited charging costs to those companies on a time and materials basis. The allocation of this position increased from 49 percent in 2011 to 75 percent in 2012. Because this position assumed additional responsibilities for BPI's newly created Customer Services Department as well as Conservation and Demand Management, there was an incremental increase in compensation.

The Board Secretary (also Director of Regulatory Affairs) had also served as the board secretary to the other companies in BPI's corporate family. That sharing ceased when the incumbent was transferred to BPI on April; 1, 2012, increasing the allocation of time to BPI from 83 percent to 100 percent. At the same time, the position was reclassified from a managerial position to a director position resulting in an incremental increase in compensation.

The cost impacts of those two changes together were $72,469 in 2012.

USoA Accounts impacted: 5605, 5610

**Changes to Work Priorities - Smart Metering and Time-of-Use Pricing**

The operating costs related to BPI's smart metering system were booked to USoA account 1556 until 2012 when the system became fully operational. Beginning January 1, 2012, those costs were booked to regular OM&A accounts. The cost driver impacts of this change to work priorities include:

- Compensation increases in the amount of $116,604 comprising the incremental increase due the reclassification of a position to a supervisory category and the equivalent of one full-time Settlement Energy Smart Meter Officer (SESMO). The reclassification incremental increase and the SESMO position had been increases to BPI's compensation in prior periods but the costs were booked to the Smart Meter Deferral and Variance accounts until 2012.

- Service fees related to the operation of the smart metering system including Sensus Tower Gateway Base (TGB) station and Savage Operational Data Store services for a net increase of $100,382 (to Account 5065); and
- A decrease to conventional meter reading contracted services and related labour costs in the amount of ($79,429).

USoA Accounts impacted: 5065, 5305, 5310, 5315

**Changes to Work Priorities – Distribution System Design**

The Distribution System Design change to work priorities includes the ongoing development and implementation of BPI's Asset Management Program and distribution system automation. These two changes to work priorities in the Engineering and Construction Department have increased OM&A costs in 2012, by $70,721. The cost increases comprise incremental increases to compensation resulting from reclassified and repurposed positions in the amount of $15,889 as well as increases to software maintenance and contracted services in the amount of $54,832.

USoA Accounts impacted: 5010, 5085

**Changes to Work Priorities – Maintenance of Line Transformers**

The cost increase is due to the replacement of failed line transformers. The change to work priorities resulted in higher inventory costs of $201,671. As in 2010, BPI has attributed only the increase to inventory costs as a cost driver as the corresponding labour and fleet costs would have been allocated to other work priorities had BPI not performed this work in 2012.

USoA Accounts impacted: 5160

**Retirement Reconciliation**

A senior staff member retired at the end of 2012 and received amounts owed in relation to a retirement.

USoA Account Impacted: 5645

**2012 to 2013 Cost Drivers**

- **Capitalization Policy Changes**

As discussed in greater detail in Exhibit 2, Tab 4, Schedule 3, the BPI Board of Directors approved a Capital Assets Policy on September 27, 2012. As that policy pertains to OM&A costs in the 2013 Test Year budget, the policy specifies that expenses that are related to administrative and general overhead are not capitalized and removes the provisions to capitalize such direct and indirect overhead costs. The cost impact of this change to BPI's capitalization policy is a cost increase of $972,502 in 2013. Table 4.18 below, sets out the distribution of this impact among all USoA accounts.

# Table 4.18 - Variance due to changes in Capitalization Policy – 2012 to 2013

| Account | Description | 2012 Bridge Year | 2013 Test Year | Variance $ | Variance Due to Changes in Capitalization Policy |
|---|---|---|---|---|---|
| ***Operations*** | | | | | |
| 5005 | Operation Supervision and Engineering | $ 226,223 | $ 273,250 | $ 47,027 | $ 45,114.00 |
| 5010 | Load Dispatching | $ 45,927 | $ 114,745 | $ 68,818 | $ 21,766.00 |
| 5012 | Station Buildings and Fixtures Expense | $ 29,252 | $ 29,322 | $ 70 | $ 4,556.00 |
| 5014 | Transformer Station Equipment - Operation Labour | $ 7,906 | $ 24,787 | $ 16,881 | $ 4,818.00 |
| 5015 | Transformer Station Equipment - Operation Supplies and Expenses | $ 75,365 | $ 102,609 | $ 27,244 | $ 17,491.00 |
| 5016 | Distribution Station Equipment - Operation Labour | $ 1,743 | $ 1,962 | $ 219 | $ 317.00 |
| 5017 | Distribution Station Equipment - Operation Supplies and Expenses | $ 400 | $ 520 | $ 120 | $ 87.00 |
| 5020 | Overhead Distribution Lines and Feeders - Operation Labour | $ 985 | $ 1,962 | $ 977 | $ 361.00 |
| 5025 | Overhead Distribution Lines and Feeders - Operation Supplies and Expenses | $ 10,893 | $ 12,752 | $ 1,859 | $ 2,086.00 |
| 5030 | Overhead Sub-transmission Feeders - Operation | $ - | $ - | $ - | $ - |
| 5035 | Overhead Distribution Transformers - Operation | $ 2,989 | $ 5,154 | $ 2,165 | $ 925.00 |
| 5040 | Underground Distribution Lines and Feeders - Operation Labour | $ 670 | $ - | -$ 670 | $ (38.00) |
| 5045 | Underground Distribution Lines and Feeders - Operation Supplies and Expenses | $ 9,508 | $ 11,990 | $ 2,482 | $ 2,004.00 |
| 5050 | Underground Sub-transmission Feeders - Operation | $ - | $ - | $ - | $ - |
| 5055 | Underground Distribution Transformers - Operation | $ 665 | $ - | -$ 665 | $ (37.00) |
| 5060 | Street Lighting and Signal System Expense | $ - | $ - | $ - | $ - |
| 5065 | Meter Expense | $ 464,155 | $ 593,094 | $ 128,939 | $ 99,464.00 |
| 5070 | Customer Premises - Operation Labour | $ 710 | $ 5,292 | $ 4,582 | $ 1,085.00 |
| 5075 | Customer Premises - Operation Materials and Expenses | $ - | $ - | $ - | $ - |
| 5085 | Miscellaneous Distribution Expenses | $ 221,832 | $ 329,209 | $ 107,377 | $ 57,268.00 |
| 5090 | Underground Distribution Lines and Feeders - Rental Paid | $ - | $ - | $ - | $ - |
| 5095 | Overhead Distribution Lines and Feeders - Rental Paid | $ 7,343 | $ 25,403 | $ 18,060 | $ 4,981.00 |
| 5096 | Other Rent | $ 4,732 | $ 44,455 | $ 39,723 | $ - |
| **Total - Operations** | | $ 1,111,298 | $ 1,576,506 | $ 465,208 | $ 262,248.00 |

| Account | Description | 2012 Bridge Year | 2013 Test Year | Variance $ | Variance Due to Changes in Capitalization Policy |
|---|---|---|---|---|---|
| ***Maintenance*** | | | | | |
| 5105 | Maintenance Supervision and Engineering | $ 432,478 | $ 499,599 | $ 67,121 | $ 81,401.00 |
| 5110 | Maintenance of Buildings and Fixtures - Distribution Stations | $ 1,559 | $ 2,158 | $ 599 | $ 370.00 |
| 5112 | Maintenance of Transformer Station Equipment | $ - | $ - | $ - | $ - |
| 5114 | Maintenance of Distribution Station Equipment | $ 6,747 | $ 9,805 | $ 3,058 | $ 1,680.00 |
| 5120 | Maintenance of Poles, Towers and Fixtures | $ 32,442 | $ 75,414 | $ 42,972 | $ 14,176.00 |
| 5125 | Maintenance of Overhead Conductors and Devices | $ 184,573 | $ 242,022 | $ 57,449 | $ 40,866.00 |
| 5130 | Maintenance of Overhead Services | $ 192,135 | $ 247,604 | $ 55,469 | $ 41,619.00 |
| 5135 | Overhead Distribution Lines and Feeders - Right of Way | $ 415,898 | $ 499,535 | $ 83,637 | $ 82,339.00 |
| 5145 | Maintenance of Underground Conduit | $ 52,661 | $ 56,902 | $ 4,241 | $ 9,075.00 |
| 5150 | Maintenance of Underground Conductors and Devices | $ 70,158 | $ 82,311 | $ 12,153 | $ 13,473.00 |
| 5155 | Maintenance of Underground Services | $ 109,059 | $ 124,877 | $ 15,818 | $ 20,291.00 |
| 5160 | Maintenance of Line Transformers | $ 305,006 | $ 192,863 | -$ 112,143 | $ 23,488.00 |
| 5165 | Maintenance of Street Lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 5170 | Sentinel Lights - Labour | $ - | $ - | $ - | $ - |
| 5172 | Sentinel Lights - Materials and Expenses | $ - | $ - | $ - | $ - |
| 5175 | Maintenance of Meters | $ 153 | $ - | -$ 153 | $ (9.00) |
| 5178 | Customer Installations Expenses - Leased Property | $ - | $ - | $ - | $ - |
| 5195 | Maintenance of Other Installations on Customer Premises | $ - | $ - | $ - | $ - |
| **Total - Maintenance** | | $ 1,802,869 | $ 2,033,090 | $ 230,221 | $ 328,769.00 |

| Account | Description | 2012 Bridge Year | 2013 Test Year | Variance $ | Variance Due to Changes in Capitalization Policy |
|---|---|---|---|---|---|
| ***Billing and Collecting*** | | | | | |
| 5305 | Supervision | $ 223,136 | $ 292,372 | $ 69,236 | $ 49,451.00 |
| 5310 | Meter Reading Expense | $ 274,993 | $ 240,556 | -$ 34,437 | $ 44,429.00 |
| 5315 | Customer Billing | $ 542,425 | $ 964,616 | $ 422,191 | $ 174,262.00 |
| 5320 | Collecting | $ 359,916 | $ 536,496 | $ 176,580 | $ 93,603.00 |
| 5325 | Collecting - Cash Over and Short | $ - | $ - | $ - | $ - |
| 5330 | Collection Charges | $ 1,000 | $ 500 | -$ 500 | $ - |
| 5335 | Bad Debt Expense | $ 300,000 | $ 306,000 | $ 6,000 | $ - |
| 5340 | Miscellaneous Customer Accounts Expenses | $ 506,862 | $ 522,675 | $ 15,813 | $ - |
| **Total - Billing and Collecting** | | $ 2,208,332 | $ 2,863,215 | $ 654,883 | $ 361,745.00 |

| Account | Description | 2012 Bridge Year | 2013 Test Year | Variance $ | Variance Due to Changes in Capitalization Policy |
|---|---|---|---|---|---|
| ***Community Relations*** | | | | | |
| 5405 | Supervision | $ - | $ - | $ - | $ - |
| 5410 | Community Relations - Sundry | $ 156,330 | $ 152,526 | -$ 3,804 | $ - |
| 5415 | Energy Conservation | $ - | $ - | $ - | $ - |
| 5420 | Community Safety Program | $ 12,807 | $ 19,051 | $ 6,244 | $ - |
| 5425 | Miscellaneous Customer Service and Informational Expenses | $ - | $ 61,200 | $ 61,200 | $ - |
| 5505 | Supervision | $ - | $ - | $ - | $ - |
| 5510 | Demonstrating and Selling Expense | $ - | $ - | $ - | $ - |
| 5515 | Advertising Expenses | $ - | $ - | $ - | $ - |
| 5520 | Miscellaneous Sales Expense | $ - | $ - | $ - | $ - |
| **Total - Community Relations** | | $ 169,137 | $ 232,777 | $ 63,640 | $ - |

| Account | Description | 2012 Bridge Year | 2013 Test Year | Variance $ | Variance Due to Changes in Capitalization Policy |
|---|---|---|---|---|---|
| ***Administrative and General Expenses*** | | | | | |
| 5605 | Executive Salaries and Expenses | $ 533,369 | $ 729,401 | $ 196,032 | $ 19,740.00 |
| 5610 | Management Salaries and Expenses | $ 340,676 | $ 384,158 | $ 43,482 | $ - |
| 5615 | General Administrative Salaries and Expenses | $ 875,651 | $ 582,990 | -$ 292,661 | $ - |
| 5620 | Office Supplies and Expenses | $ 58,468 | $ 80,250 | $ 21,782 | $ - |
| 5625 | Administrative Expense Transferred - Credit | $ - | $ - | $ - | $ - |
| 5630 | Outside Services Employed | $ 138,735 | $ 220,000 | $ 81,265 | $ - |
| 5635 | Property Insurance | $ 100,861 | $ 133,133 | $ 32,272 | $ - |
| 5640 | Injuries and Damages | $ - | $ - | $ - | $ - |
| 5645 | OMERS Pensions and Benefits | $ 302,000 | $ 108,000 | -$ 194,000 | $ - |
| 5646 | Employee Pensions and OPEB | $ - | $ - | $ - | $ - |
| 5647 | Employee Sick Leave | $ - | $ - | $ - | $ - |
| 5650 | Franchise Requirements | $ 57,569 | $ 59,000 | $ 1,431 | $ - |
| 5655 | Regulatory Expenses | $ 135,500 | $ 144,500 | $ 9,000 | $ - |
| 5660 | General Advertising Expenses | $ 13,600 | $ 40,000 | $ 26,400 | $ - |
| 5665 | Miscellaneous General Expenses | $ 8,341 | -$ 1,995 | -$ 10,336 | $ - |
| 5670 | Rent | $ - | $ - | $ - | $ - |
| 5672 | Lease Payment Charge | $ - | $ - | $ - | $ - |
| 5675 | Maintenance of General Plant | $ - | $ - | $ - | $ - |
| 5680 | Electrical Safety Authority Fees | $ 16,400 | $ 19,000 | $ 2,600 | $ - |
| 5681 | Special Purpose Charge Expense | $ - | $ - | $ - | $ - |
| 5685 | Independent Electricity System Operator Fees and Penalties | $ 60,000 | $ - | -$ 60,000 | $ - |
| 5695 | OM&A Contra Account | -$ 120,132 | $ - | $ 120,132 | $ - |
| 6205 | Donations | $ - | $ - | $ - | $ - |
| 6205 | Donations, Sub-account LEAP Funding | | | | $ - |
| **Total - Administrative and General Expenses** | | $ 2,521,038 | $ 2,498,437 | -$ 22,601 | $ 19,740.00 |
| **Total OM&A** | | $ 7,812,674 | $ 9,204,025 | $ 1,391,351 | $ 972,502 |

- **Restructuring – Customer Services**

Although staff was transferred to BPI on April 1, 2012, the City and BPI continued to issue a joint customer invoice to May 6, 2013. The splitting of the bill has resulted in full disaggregation of the City and BPI workforces, customer information systems, telephone systems and, ultimately, costs.

The cost impacts are as follows:

Staff complement has been increased by 1 FTE to accommodate workload levels that have remained consistent but handled by fewer staff. For example, the number of calls handled by Customer Service staff have remained consistent with previous years although of shorter duration as staff address only BPI matters. BPI notes that while staff complement has increased by another FTE, a cashier, the cost of this position has been offset by reductions to service fees for cashiering services previously paid to the City.

Costs for goods and services have increased by $289,405 comprising increases due to the splitting of the bill for postage, paper for bill printing and rental of equipment to process customer invoices in the amount of $213,006 and other contracted services such as lock box services to allow customers to pay bills at a local bank, collection notice delivery and after hours call centre services in the amount of $76,399.

USoA Accounts impacted: 5310, 5315, 5320, 5340

- **Restructuring – Finance Services**

The combination of the resource deficit in the Finance Department transfer, new accountabilities and ongoing transitional activities has created the need for an additional staff resource in the Finance Department in the amount of $77,000. Starting in 2013, the costs of the Finance Department are allocated as indirect costs to other operating areas and as a result, this increase in not attributable to a specific USoA account.

USoA Accounts impacted: Various OM&A accounts.

# VARIANCE ANALYSIS ON OM&A COSTS

## Introduction

Consistent with the Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2012, BPI has provided variance analyses for the 2013 Test Year vs. 2008 Actual (last rebase year) and between the 2013 Test Year and 2011 Actual (Most Current Actual). BPI has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $70,000. The variances are indicated in the following tables and an explanation of each variance is presented in the following section.

The following discussion is provided as background to clarify the subsequent variance analysis

## 2008 Board Approved vs. 2008 Actual

In accordance with the Minimum Filing Requirements, BPI has analyzed variances back to the 2008 Board Approved values as well as 2008 actual amounts. As noted above in the discussion of cost drivers, the variance between 2008 Board Approved amounts and 2008 expenses was due to changes in work priorities between the preparation of BPI's 2008 Cost-of-Service Rate Application and the approval of the 2008 budget against which managers managed costs, by the BPI Board of Directors. BPI has noted the impact of this variance to specific USoA accounts in the following variance analysis.

## Reallocations of Costs

One of the outcomes of the corporate reorganization, changes to management structure and incumbents filling those positions has been numerous changes to where costs are classified or booked year-over-year. For example, the allocation of labour costs between USoA Accounts 5005 and 5105 have varied year-over-year with the result that changes with Account 5005 are generally offset by changes to 5105. While these reallocations may cause variances over the materiality threshold, they do not cause either increases or decreases to costs. Cost increases are best observed through the sum of the accounts as set out in Table 4.19 below.

**Table 4.19 - Reallocations of management costs between Account 5005 and 5105 – 2008 to 2013**

| Account | Description | 2008 | 2009 | Variance | 2010 | Variance | 2011 | Variance | 2012 | Variance | 2013 | Variance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5005 | Operation Supervision & Engineering | $ 311,749 | $ 332,926 | $ 21,177 | $ 335,123 | $ 2,196 | $ 327,414 | -$ 7,709 | $ 226,223 | -$101,191 | $ 273,250 | $ 47,027 |
| 5105 | Maintenance Supervision and Engineering | $301,446 | $304,849 | $ 3,403 | $325,801 | $ 20,952 | $307,486 | -$ 18,315 | $432,478 | $124,992 | $499,599 | $ 67,121 |
| **Total** | **5005 and 5105** | **$ 613,195** | **$ 637,775** | **$ 24,580** | **$ 660,924** | **$ 23,149** | **$ 634,900** | **-$ 26,024** | **$ 658,701** | **$ 23,801** | **$ 772,849** | **$ 114,148** |
| | | | | | | | | | | | | |
| **NOTES:** | | | | | | | | | | | | |
| 1 | The decrease of ($26,024) in 2011 from 2010 is attributable to the removal of the 10% mark-up paid on services purchased from the City | | | | | | | | | | | |
| 2 | The increase of $114,148 in 2013 over 2012 is attributable to increases due to changes to capitalization policy of $126,515 offset by cost decreases due to organizational restructuring | | | | | | | | | | | |

Reallocations of costs impact many USoA accounts and these have been noted in the following variance analysis.

## 5300 Series Materiality and Variance Analysis

Organizational restructuring and changes to work priorities like the operationalization of smart metering and implementation of time-of-use pricing have impacted the costs charged to the 5300 – Billing and collecting Series of accounts for the period of 2011 to 2013.

The following is a high level description and breakdown of the 5300 series of accounts. The costs in these accounts are coming from two different departments. They are the Metering and Settlement Department of the Energy and Operations department and the Customer Services department.

As discussed above with respect to the overview of the Cost Driver Table, the three staff of the Metering and Settlement Department, some of whose time is booked to the 5300 series of accounts, was transferred from the City to BPI on April 1, 2102. At the same time, the existing Utilities Customer Services Division of the City was split between Water/BHI Customer Services, which remained with the City and BPI Customer Services, which was transferred to BPI. An equivalent of 11 full-time positions was transferred to BPI although some of those positions were vacant at the time of transfer.

Prior to the April 1, 2012 transfer, both Metering and Settlement and Customer Services charges were billed to BPI from the City in the form of service level fees. Following the transfer, BPI has directly paid for the costs related to those functions.

These transitions in 2012 and 2013 hinder a straightforward analysis over the materiality threshold of the 5300 series accounts. Prior to the transfer of employees, costs were distributed among the 5300 series using reasonable allocators. Those distributions have changed starting in 2012 as BPI began to charge its directly incurred costs to the 5300 series of accounts. That is, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs that are neither increases to, or decreases from costs.

To mitigate the impact of account reallocations, BPI has undertaken a materiality and variance analysis below, using the total of the 5300 series. In keeping with the Board's Minimum Filing Guidelines, BPI has also undertaken materiality and variance analysis at the individual USoA account level. Examining the total variance, BPI suggests, provides a more clear understanding of how and why costs have changed while minimizing the impacts of account reclassifications.

**Table 4.20 - 5300 Series of Accounts Variance – 2011 to 2013**

| Account | Description | 2011 | 2013 | Variance $ |
|---|---|---|---|---|
| ***Billing and Collecting*** | | | | |
| 5305 | Supervision | $ 161,326 | $ 292,372 | $ 131,046 |
| 5310 | Meter Reading Expense | $ 354,422 | $ 240,556 | -$ 113,866 |
| 5315 | Customer Billing | $ 495,101 | $ 964,616 | $ 469,515 |
| 5320 | Collecting | $ 322,653 | $ 536,496 | $ 213,843 |
| 5325 | Collecting - Cash Over and Short | $ - | $ - | $ - |
| 5330 | Collection Charges | $ 833 | $ 500 | -$ 333 |
| 5335 | Bad Debt Expense | $ 307,532 | $ 306,000 | -$ 1,532 |
| 5340 | Miscellaneous Customer Accounts Expenses | $ 403,316 | $ 522,675 | $ 119,359 |
| **Total - Billing and Collecting** | | **$ 2,045,182** | **$ 2,863,215** | **$ 818,033** |

The variance from 2011 to 2013 is an increase of $818,033 as set out in Table 4.21.

**Table 4.21 - 5300 Series Total Variance from 2011 to 2013**

| **Variance - 2011 to 2013** | **$818,033** |
|---|---|
| | |
| Changes to capitalization policy | $361,745 |
| Increases to Staffing and Compensation – Metering & Settlement | $116,604 |
| Increases to Staffing and Compensation – Customer Services | $199,185 |
| Supplies and Contracted Services – Customer Services | $289,405 |
| Other miscellaneous costs – Metering and Settlement; Customer Services | ($12,105) |
| **Subtotal** | **$954,834** |
| Indirect Costs allocated to 5300 Series | ($136,801) |
| **Total** | **$818,033** |

The primary causes of this increase are:

- Increases due to changes in capitalization policy allocated to this series of accounts totaling $361,745;
- Increases to compensation costs to the Metering and Settlement Department due to reclassification of a position to a supervisory position and the addition of the equivalent of one Settlement, Energy and Smart Metering Officer (SESMO) to staff complement totaling $116,604;
- An increase of one full-time equivalent employee to the Customer Services Department totaling $71,100. The remainder of the Customer Service compensation is attributable to revenue recognition practices related to City water and sewer customer care services in the amount of $128,085. For detailed discussion of this revenue recognition practice, please refer to Exhibit 4, Tab 2, Schedule 4, (2011 to 2012 Cost Drivers – Restructuring – Customer Services);
- Increases due to the splitting of the customer invoices including an increase in postage supplies and equipment rental fees in the amount of $161,464, and other contracted services such as lock box rental services in the amount of $76,399 for a total increase of $289,405.

**Table 4.22 - 5300 Series of Accounts Variance – 2008 to 2013**

| Account | Description | 2008 | 2013 | Variance $ |
|---|---|---|---|---|
| ***Billing and Collecting*** | | | | |
| 5305 | Supervision | $ 167,397 | $ 292,372 | $ 124,975 |
| 5310 | Meter Reading Expense | $ 409,719 | $ 240,556 | -$ 169,163 |
| 5315 | Customer Billing | $ 517,916 | $ 964,616 | $ 446,700 |
| 5320 | Collecting | $ 334,793 | $ 536,496 | $ 201,703 |
| 5325 | Collecting - Cash Over and Short | $ - | $ - | $ - |
| 5330 | Collection Charges | $ 282 | $ 500 | $ 218 |
| 5335 | Bad Debt Expense | $ 130,318 | $ 306,000 | $ 175,682 |
| 5340 | Miscellaneous Customer Accounts Expenses | $ 418,492 | $ 522,675 | $ 104,183 |
| **Total - Billing and Collecting** | | $ 1,978,917 | $ 2,863,215 | $ 884,298 |

The variance from 2008 to 2013 is an increase of $884,298. Along with the causes of the increases from 2011 to 2013, an increase in bad debt expense in the amount of $175,682 offset by a decrease due to the removal of the 10% mark-up on services and a reallocation of costs between BPI and its retail affiliate BHI from a 96/4 split to a 90/10 split in 2011, is the main cause of this increase.

## Variance Analysis on OM&A Costs - Detail

BPI has provided a detailed OM&A expense analysis covering the periods from BPI's last Cost-of-Service Rate Application. An analysis of expense changes by cost driver is provided in Table 4.23 with year-to-year explanations. Tables 4.18 to 4.22 set out the variances from 2008 Board Approved to 2013 and 2011 to 2013 expenses for all of BPI's operating expenses. An analysis of variances in those USoA accounts over the $70,000 materiality follows those tables.

# Table 4.23 – Operations Expenses

| Account | Description | Last Board-approved Rebasing Year (2008 Year) | 2008 Actual | Most Current Actuals Year 2011 | Test Year 2013 | 2008 Board Approved Versus 2008 Actual | | Test Year Versus Last Rebasing | | Test Year Versus Most Current Actuals | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Variance ($) | Percentage | Variance ($) | Percentage | Variance ($) | Percentage |
| Reporting Basis | | CGAAP | CGAAP | CGAAP | CGAAP | | | | | | |
| *Operations* | | | | | | | | | | | |
| 5005 | Operation Supervision and Engineering | $ 244,352 | $ 311,749 | $ 327,414 | $ 273,250 | $ 67,397 | 28% | $ 28,898 | 11.83% | -$ 54,164 | -16.54% |
| 5010 | Load Dispatching | $ 16,375 | $ 38,989 | $ 31,918 | $ 114,745 | $ 22,614 | 138% | $ 98,370 | 600.73% | $ 82,827 | 259.50% |
| 5012 | Station Buildings and Fixtures Expense | $ 36,464 | $ 40,428 | $ 25,755 | $ 29,322 | $ 3,964 | 11% | -$ 7,142 | -19.59% | $ 3,567 | 13.85% |
| 5014 | Transformer Station Equipment - Operation Labour | $ 6,205 | $ 6,002 | $ 15,354 | $ 24,787 | -$ 203 | -3% | $ 18,582 | 299.47% | $ 9,433 | 61.44% |
| 5015 | Transformer Station Equipment - Operation Supplies and Expenses | $ 51,220 | $ 77,928 | $ 96,171 | $ 102,609 | $ 26,708 | 52% | $ 51,389 | 100.33% | $ 6,439 | 6.69% |
| 5016 | Distribution Station Equipment - Operation Labour | $ 1,959 | $ 2,481 | $ 4,208 | $ 1,962 | $ 522 | 27% | $ 3 | 0.15% | -$ 2,246 | -53.37% |
| 5017 | Distribution Station Equipment - Operation Supplies and Expenses | $ 3,612 | $ 3,421 | $ 1,155 | $ 520 | -$ 191 | -5% | -$ 3,092 | -85.60% | -$ 635 | -54.98% |
| 5020 | Overhead Distribution Lines and Feeders - Operation Labour | $ 3,019 | $ 1,222 | $ 1,928 | $ 1,962 | -$ 1,797 | -60% | -$ 1,057 | -35.01% | $ 34 | 1.78% |
| 5025 | Overhead Distribution Lines and Feeders - Operation Supplies and Expenses | $ 13,806 | $ 720 | $ 1,976 | $ 12,752 | -$ 13,086 | -95% | -$ 1,054 | -7.63% | $ 10,776 | 545.23% |
| 5030 | Overhead Sub-transmission Feeders - Operation | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5035 | Overhead Distribution Transformers - Operation | $ 14,800 | $ 1,044 | $ 3,868 | $ 5,154 | -$ 13,756 | -93% | -$ 9,646 | -65.18% | $ 1,286 | 33.25% |
| 5040 | Underground Distribution Lines and Feeders - Operation Labour | $ 1,043 | $ 1,137 | $ 1,178 | $ - | $ 94 | 9% | -$ 1,043 | -100.00% | -$ 1,178 | -100.00% |
| 5045 | Underground Distribution Lines and Feeders - Operation Supplies and Expenses | $ 18,921 | $ 11,204 | $ 6,267 | $ 11,990 | -$ 7,717 | -41% | -$ 6,931 | -36.63% | $ 5,723 | 91.32% |
| 5050 | Underground Sub-transmission Feeders - Operation | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5055 | Underground Distribution Transformers - Operation | $ 3,290 | $ 1,830 | $ 685 | $ - | -$ 1,460 | -44% | -$ 3,290 | -100.00% | -$ 685 | -100.00% |
| 5060 | Street Lighting and Signal System Expense | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5065 | Meter Expense | $ 452,578 | $ 305,437 | $ 363,773 | $ 593,094 | -$ 147,141 | -33% | $ 140,516 | 31.05% | $ 229,321 | 63.04% |
| 5070 | Customer Premises - Operation Labour | $ 5,979 | $ 897 | $ 461 | $ 5,292 | -$ 5,082 | -85% | -$ 687 | -11.49% | $ 4,831 | 1048.04% |
| 5075 | Customer Premises - Operation Materials and Expenses | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5085 | Miscellaneous Distribution Expenses | $ 118,312 | $ 214,419 | $ 182,823 | $ 329,209 | $ 96,107 | 81% | $ 210,897 | 178.25% | $ 146,386 | 80.07% |
| 5090 | Underground Distribution Lines and Feeders - Rental Paid | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5095 | Overhead Distribution Lines and Feeders - Rental Paid | $ 6,285 | $ - | $ 6,869 | $ 25,403 | -$ 6,285 | -100% | $ 19,118 | 304.18% | $ 18,534 | 269.82% |
| 5096 | Other Rent | $ - | $ - | $ 4,540 | $ 44,455 | $ - | | $ 44,455 | | $ 39,915 | 879.26% |
| **Total - Operations** | | $ 998,220 | $ 1,018,908 | $ 1,076,343 | $ 1,576,506 | $ 20,688 | 2% | $ 578,286 | 57.93% | $ 500,163 | 46.47% |

## Table 4.24 – Maintenance Expenses

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ***Maintenance*** | | | | | | | | | | |
| 5105 Maintenance Supervision and Engineering | $ 280,966 | $ 301,446 | $ 307,486 | $ 499,599 | $ 20,480 | 7% | $ 218,633 | 77.81% | $ 192,113 | 62.48% |
| 5110 Maintenance of Buildings and Fixtures - Distribution Stations | $ 3,970 | $ - | $ 1,892 | $ 2,158 | -$ 3,970 | -100% | -$ 1,812 | -45.64% | $ 266 | 14.06% |
| 5112 Maintenance of Transformer Station Equipment | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5114 Maintenance of Distribution Station Equipment | $ 16,206 | $ 7,164 | $ 5,684 | $ 9,805 | -$ 9,042 | -56% | -$ 6,401 | -39.50% | $ 4,121 | 72.50% |
| 5120 Maintenance of Poles, Towers and Fixtures | $ 153,188 | $ 182,780 | $ 44,139 | $ 75,414 | $ 29,592 | 19% | -$ 77,774 | -50.77% | $ 31,275 | 70.86% |
| 5125 Maintenance of Overhead Conductors and Devices | $ 194,468 | $ 116,671 | $ 196,827 | $ 242,022 | -$ 77,797 | -40% | $ 47,554 | 24.45% | $ 45,195 | 22.96% |
| 5130 Maintenance of Overhead Services | $ 201,225 | $ 230,266 | $ 218,602 | $ 247,604 | $ 29,041 | 14% | $ 46,379 | 23.05% | $ 29,002 | 13.27% |
| 5135 Overhead Distribution Lines and Feeders - Right of Way | $ 333,592 | $ 443,359 | $ 348,542 | $ 499,535 | $ 109,767 | 33% | $ 165,943 | 49.74% | $ 150,993 | 43.32% |
| 5145 Maintenance of Underground Conduit | $ 66,733 | $ 43,295 | $ 54,614 | $ 56,902 | -$ 23,438 | -35% | -$ 9,831 | -14.73% | $ 2,288 | 4.19% |
| 5150 Maintenance of Underground Conductors and Devices | $ 111,669 | $ 78,960 | $ 71,835 | $ 82,311 | -$ 32,709 | -29% | -$ 29,358 | -26.29% | $ 10,476 | 14.58% |
| 5155 Maintenance of Underground Services | $ 204,053 | $ 210,769 | $ 138,372 | $ 124,877 | $ 6,716 | 3% | -$ 79,176 | -38.80% | -$ 13,495 | -9.75% |
| 5160 Maintenance of Line Transformers | $ 159,264 | $ 142,265 | $ 68,591 | $ 192,863 | -$ 16,999 | -11% | $ 33,599 | 21.10% | $ 124,272 | 181.18% |
| 5165 Maintenance of Street Lighting and Signal Systems | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5170 Sentinel Lights - Labour | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5172 Sentinel Lights - Materials and Expenses | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5175 Maintenance of Meters | $ - | $ 171 | $ - | $ - | $ 171 | | $ - | | $ - | |
| 5178 Customer Installations Expenses - Leased Property | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5195 Maintenance of Other Installations on Customer Premises | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| **Total - Maintenance** | $ 1,725,334 | $ 1,757,147 | $ 1,456,583 | $ 2,033,090 | $ 31,813 | 2% | $ 307,756 | 17.84% | $ 576,507 | 39.58% |

## Table 4.25 – Billing and Collecting Expenses

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ***Billing and Collecting*** | | | | | | | | | | |
| 5305 Supervision | $ 135,049 | $ 167,397 | $ 161,326 | $ 292,372 | $ 32,348 | 24% | $ 157,323 | 116.49% | $ 131,046 | 81.23% |
| 5310 Meter Reading Expense | $ 371,227 | $ 409,719 | $ 354,422 | $ 240,556 | $ 38,492 | 10% | -$ 130,671 | -35.20% | -$ 113,866 | -32.13% |
| 5315 Customer Billing | $ 466,741 | $ 517,916 | $ 495,101 | $ 964,616 | $ 51,175 | 11% | $ 497,875 | 106.67% | $ 469,515 | 94.83% |
| 5320 Collecting | $ 300,111 | $ 334,793 | $ 322,653 | $ 536,496 | $ 34,682 | 12% | $ 236,385 | 78.77% | $ 213,843 | 66.28% |
| 5325 Collecting - Cash Over and Short | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5330 Collection Charges | $ 2,251 | $ 282 | $ 833 | $ 500 | -$ 1,969 | -87% | -$ 1,751 | -77.79% | -$ 333 | -39.99% |
| 5335 Bad Debt Expense | $ 183,090 | $ 130,318 | $ 307,532 | $ 306,000 | -$ 52,772 | -29% | $ 122,910 | 67.13% | -$ 1,532 | -0.50% |
| 5340 Miscellaneous Customer Accounts Expenses | $ 649,367 | $ 418,492 | $ 403,316 | $ 522,675 | -$ 230,875 | -36% | -$ 126,692 | -19.51% | $ 119,359 | 29.59% |
| **Total - Billing and Collecting** | $ 2,107,836 | $ 1,978,917 | $ 2,045,182 | $ 2,863,215 | -$ 128,919 | -6% | $ 755,379 | 35.84% | $ 818,033 | 40.00% |

## Table 4.26 – Community Relations

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ***Community Relations*** | | | | | | | | | | |
| 5405 Supervision | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5410 Community Relations - Sundry | $ 114,588 | $ 106,288 | $ 106,211 | $ 152,526 | -$ 8,300 | -7% | $ 37,938 | 33.11% | $ 46,315 | 43.61% |
| 5415 Energy Conservation | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5420 Community Safety Program | $ 12,743 | $ 6,949 | $ 9,412 | $ 19,051 | -$ 5,794 | -45% | $ 6,308 | 49.50% | $ 9,639 | 102.41% |
| 5425 Miscellaneous Customer Service and Informational Expenses | $ - | $ - | $ - | $ 61,200 | $ - | | $ 61,200 | | $ 61,200 | |
| 5505 Supervision | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5510 Demonstrating and Selling Expense | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5515 Advertising Expenses | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5520 Miscellaneous Sales Expense | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| **Total - Community Relations** | $ 127,331 | $ 113,237 | $ 115,623 | $ 232,777 | -$ 14,094 | -11% | $ 105,446 | 82.81% | $ 117,154 | 101.32% |

# Table 4.27 – Administrative and General Expenses

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ***Administrative and General Expenses*** | | | | | | | | | | |
| 5605 Executive Salaries and Expenses | $ 392,793 | $ 424,360 | $ 319,673 | $ 729,401 | $ 31,567 | 8% | $ 336,608 | 85.70% | $ 409,728 | 128.17% |
| 5610 Management Salaries and Expenses | $ 662,071 | $ 370,449 | $ 302,363 | $ 384,158 | -$ 291,622 | -44% | -$ 277,913 | -41.98% | $ 81,795 | 27.05% |
| 5615 General Administrative Salaries and Expenses | $ 664,697 | $ 909,393 | $ 884,744 | $ 582,990 | $ 244,696 | 37% | -$ 81,707 | -12.29% | -$ 301,754 | -34.11% |
| 5620 Office Supplies and Expenses | $ 48,202 | $ 65,707 | $ 51,082 | $ 80,250 | $ 17,505 | 36% | $ 32,048 | 66.49% | $ 29,168 | 57.10% |
| 5625 Administrative Expense Transferred - Credit | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5630 Outside Services Employed | $ 164,324 | $ 110,786 | $ 127,715 | $ 220,000 | -$ 53,538 | -33% | $ 55,676 | 33.88% | $ 92,285 | 72.26% |
| 5635 Property Insurance | $ - | $ 151,793 | $ 99,678 | $ 133,133 | $ 151,793 | | $ 133,133 | | $ 33,455 | 33.56% |
| 5640 Injuries and Damages | $ - | $ 12,642 | $ - | $ - | $ 12,642 | | $ - | | $ - | |
| 5645 OMERS Pensions and Benefits | $ 101,036 | $ 220,062 | $ 175,099 | $ 108,000 | $ 119,026 | 118% | $ 6,964 | 6.89% | -$ 67,099 | -38.32% |
| 5646 Employee Pensions and OPEB | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5647 Employee Sick Leave | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5650 Franchise Requirements | $ 49,316 | $ 50,130 | $ 53,775 | $ 59,000 | $ 814 | 2% | $ 9,684 | 19.64% | $ 5,225 | 9.72% |
| 5655 Regulatory Expenses | $ 196,822 | $ 248,012 | $ 120,735 | $ 144,500 | $ 51,190 | 26% | -$ 52,322 | -26.58% | $ 23,765 | 19.68% |
| 5660 General Advertising Expenses | $ 23,802 | $ 27,062 | $ 15,894 | $ 40,000 | $ 3,260 | 14% | $ 16,198 | 68.05% | $ 24,107 | 151.68% |
| 5665 Miscellaneous General Expenses | $ 171,754 | $ 184,695 | $ 151,291 | -$ 1,995 | $ 12,941 | 8% | -$ 173,749 | -101.16% | -$ 153,286 | -101.32% |
| 5670 Rent | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5672 Lease Payment Charge | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5675 Maintenance of General Plant | $ 54,927 | $ - | $ - | $ - | -$ 54,927 | -100% | -$ 54,927 | -100.00% | $ - | |
| 5680 Electrical Safety Authority Fees | $ 18,309 | $ 15,642 | $ 16,013 | $ 19,000 | -$ 2,667 | -15% | $ 691 | 3.77% | $ 2,987 | 18.66% |
| 5681 Special Purpose Charge Expense | $ - | $ - | $ - | $ - | $ - | | $ - | | $ - | |
| 5685 Independent Electricity System Operator Fees and Penalties | $ - | $ 54,425 | $ 51,758 | $ - | $ 54,425 | | $ - | | -$ 51,758 | -100.00% |
| 5695 OM&A Contra Account | $ - | -$ 19,371 | -$ 51,215 | $ - | -$ 19,371 | | $ - | | $ 51,215 | -100.00% |
| 6205 Donations | $ - | | | | $ - | | $ - | | $ - | |
| 6205 Donations, Sub-account LEAP Funding | $ - | $ - | $ - | | $ - | | $ - | | $ - | |
| **Total - Administrative and General Expenses** | $ 2,548,053 | $ 2,825,788 | $ 2,318,604 | $ 2,498,437 | $ 277,735 | 11% | -$ 49,616 | -1.95% | $ 179,833 | 7.76% |
| **Total OM&A** | $ 7,506,774 | $ 7,693,996 | $ 7,012,336 | $ 9,204,025 | $ 187,222 | 2% | $ 1,697,251 | 22.61% | $ 2,191,689 | 31.25% |

## 2008 Board Approved - 2013 Test Year

**5010 – Load Dispatching $98,370**

$22,614 less was budgeted for in the 2008 Board Approved than was spent in the 2008 actual year.

There was a $23,889 increase in costs that are the result of changes to BPI's capitalization policy, which eliminates the capitalization of certain Administrative and General expenses. Please refer to Exhibit 2, Tab 3, Schedule 3 for further details.

There was a $23,012 increase in salaries and benefits in the Engineering department. This is discussed further in Exhibit 4, Tab 2, Schedule 5 of the Employee Compensation section. The reclassification of a position in the Engineering department is a result of changes in work priorities and a focus on SCADA maintenance and support and other computer software. The cost of maintenance and support for SCADA was an increase of $26,457, of which $15,000 was for contracted services.

**5065 – Meter Expense $140,516**

$147,141 more was budgeted in 2008 Board Approved than what was spent in the 2008 actual year.

There was an increase in the amount of $112,098 due to the change in the capitalization policy, which resulted in higher OM&A costs in 2013.

There was a $49,123 increase in salaries and benefits over the 5-year period in the Metering and Settlement department. This increase was a result of a promotion in the department in 2011, a promotion in 2012 and increased training costs to assist with training a new employee. Further details are available in Exhibit 4, Tab 2, Schedule 5 in the Employee Compensation section**.**

Costs pertaining to these individuals are allocated over a series of accounts, including capital.

With the operationalization of smart metering in 2012, OM&A costs previously recorded in USoA account 1556, were booked to this account causing increases.

There was an increase in the amount of $139,440 for contracted services for Smart Meter OM&A which includes Sensus Tower Gateway Base Station and Savage Operational Data Store.

**5085 – Miscellaneous Distribution Expense $210,897**

$96,107 less was budgeted in the 2008 Board-Approved than what was spent in the 2008 actual year.

There was a $67,179 increase due to the change in BPI's capitalization policy.

A decrease in the amount of ($17,893) related to the removal of the City's mark-up which was no longer charged by the City from 2011 onward.

There was a $24,243 increase in salaries and wages in the Engineering department. Details can be found in Exhibit 4, Tab 2, Schedule 5 in the Employee Compensation section.

There was a $32,085 increase in contracted services, some of which involve support and maintenance of Integraph, Asset Management, ESA Audit, Standards approval and support. There was an increase in computer software fees in the amount of $20,960. Some of the software involved was Integraph, Bentley, AutoCad and TOAD maintenance.

A ($6,976) decrease related to office furniture in the Operations department. This included such items as security cameras, blinds and printers that were purchased in one year but not in the subsequent year.

**5105 – Maintenance Supervision & Engineering $218,633**

$20,480 less was budgeted in the 2008 Board Approved budget than what was spent in the 2008 actual year.

The salary for the Director of Engineering was reallocated from account 5005 to 5105. This is not an increased cost, but simply an account reclassification that resulted in more costs being booked to account 5105.

An increase in the amount of $102,266 is a result of an increase due to the change in BPI's capitalization policy, resulting in higher OM&A costs.

A ($31,788) decrease is due to the removal of the mark-up which was no longer charged by the City from 2011 onward.

There was an $11,098 increase in salaries and benefits in the Engineering department. Details can be found in Exhibit 4, Tab 2, Schedule 5 in the Employee Compensation section.

A $9,804 increase is due to BPI no longer charging costs of supervisory activities for BHI as these services are no longer provided to BHI.

**5120 – Maintenance Poles, Towers & Fixtures ($77,774)**

$29,592 less was budgeted in the 2008 Board Approved than what was spent in the 2008 actual year.

In 2012, the Director of Operations retired and a new person filled the position. In keeping with ongoing improvements to BPI's budgeting and financial reporting systems to allow more accurate recording of costs to USoA accounts, the current Director took different approaches in the manner that amounts were allocated between accounts in the budgeting process. Because of the different way that the allocations were completed, account 5120 experienced a decrease of ($12,032) in wages and benefits and a ($24,858) decrease in inventory charges. These are not actual cost decreases, just funds being reallocated from one account to another.

There was an increase in the amount of $13,619 costs due to the change in BPI's capitalization policy.

There was a ($51,626) decrease in contracted services and construction of which $44,958 was used for pole care that BPI is now capitalizing and amortizing over a 3 year period and $6,718 was for contracted services work.

There was a ($15,591) decrease in education and staff development, which related to the line maintainers. Other decreases included a ($9,709) decrease in fleet charges and an ($8,802) decrease due to removal of the mark-up which was no longer charged by the City from 2011 onward.

**5135 – Overhead Distribution Lines and Feeders – Right of Way $165,943**

$109,767 less was budgeted in the 2008 Board Approved than what was spent in the 2008 actual year.

There was an $8,387 increase in salaries and benefits. Forestry services increased by approximately $100,000 due to a scheduled cost increase in the existing multi-year contract with the third-party service provider and OM&A costs increased by $100,131 due to BPI's change in capitalization policy.

**5155 – Maintenance of Underground Services ($79,176)**

$6,716 less was budgeted in the 2008 Board Approved than what was spent in the 2008 actual year.

As discussed above, the former and current Director of Operations took different approaches in the manner that allocations were completed between accounts in the budgeting process. Because of the different way that the allocations were completed, account 5155 experienced a decrease of ($26,641) in wages and benefits and a ($33,786) decrease in inventory charges.

A $23,768 increase is a result of BPI's change in capitalization policy, which results in higher OM&A costs.

There was a ($22,217) decrease in contracted construction, a ($15,287) decrease in fleet charges and an ($11,690) decrease due to removal of the mark-up that which was no longer charged by the City from 2011 onward.

**5305 – Supervision $157,323**

$32,348 less was budgeted in the 2008 Board Approved than what was spent in the 2008 actual year.

There was an increase in salary and benefits in the Metering and Settlement department for a Supervisor role promoted in 2011.

The majority of the salary and benefits for the Supervisor of the Metering and Settlement department, $94,138, is now being allocated to account 5305, whereas before part of the salary and benefits were mostly allocated to accounts 5065 and 5310.

Also in Customer Services, the Supervisor was reclassified as a Manager. Please refer to the discussion of the 5300 account series in Exhibit 4, Tab 2, Schedule 5.

An increase of $49,451 was a result of the change in BPI's capitalization policy.

There was a decrease in the amount of ($6,696) related to staffing costs such as staff development, phones and parking.

Indirect costs such as property costs, human resources and I.T. services decreased by ($11,708).

Another contributor to the variance is removal of the 10% mark-up which was no longer charged by the City from 2011 onward.

**5310 – Meter Reading Expense ($130,671)**

$38,492 less was budgeted in the 2008 Board Approved than what was spent in the 2008 actual year.

Compensation decreased in the Metering and Settlement department by ($39,447). This decrease is a result of a change in account classification. As indicated in account 5305, the salary and benefits of the Supervisor role in the Metering and Settlement department were reallocated to account 5305, hence the decrease in account 5310. Additionally, 21% of the salary and benefits of two Settlement Officers and 10% of the salary and benefits of two Meter Technicians were allocated to this account from account 5065 and the Smart Meter Capital account.

There was a ($42,000) decrease in this account as this amount related to the Smart Meter OM&A contra account and was reallocated to account 5695.

Other expenses on the Metering and Settlement side include computer software and staffing costs at an increase of $8,838. There was also a cost decrease for contracted services and internal labour costs for conventional meter reading by ($34,437).

Cost for supplies, software and contracted services decreased in the amount of ($28,068) and staffing costs such as staff development, fleet and phones decreased by ($12,139).

The change in BPI's capitalization policy resulted in a cost increase of $44,429.

The indirect costs in 2013 have decreased by ($22,493). Another contributor to the variance is removal of the 10% mark-up which was no longer charged by the City from 2011 onward.

In terms of the remainder of the increase, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5315 – Customer Billing $497,875**

$51,175 less was budgeted in the 2008 Board Approved than was spent in the 2008 actual year.

There was a $37,308 increase in Metering and Settlement salaries and benefits. This increase is a result of two Settlement Officers being allocated to this account that were not in this account previously. In 2011, one Metering and Settlement representative was allocated fully to account

5065 and the other representative was in a Smart Meter Capital account. 25% of the salaries and benefits for both representatives have now been allocated to account 5315.

Customer Service staffing costs, including staff development, phones and fleet costs represent a decrease in the amount of ($31,654).

The indirect costs for General and Administrative costs charged under the SSA decreased in the amount of ($58,011).

Other charges that are now being incurred by BPI since the transition include postage, supplies (paper for bills) and equipment which have resulted in an increased cost of $264,405.

A $7,118 increase was the result of various charges, including education, parking, travel, phones and meals.

There was an increase in the amount of $174,262 due to the change in BPI's capitalization policy.

Another contributor to the variance is removal of the 10% mark-up which was no longer charged by the City from 2011 onward.

In terms of the remainder of the increase, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5320 – Collecting $236,385**

$34,682 less was budgeted in the 2008 Board Approved than was spent in the 2008 actual year.

Staffing costs such as staff development, fleet costs and phones decreased by ($12,002).

An increase of $93,603 was a result of the change in BPI's capitalization policy.

Indirect costs for General and Administrative costs charged under the SSA decreased in the amount of ($27,360).

There was an increase in the amount of $25,000 for bank charges for a drop box. Another contributor to the variance is removal of the 10% mark-up which was no longer charged by the City from 2011 onward.

In terms of the remainder of the increase, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5335 – Bad Debt Expense $122,910**

$52,772 more was budgeted in the 2008 Board Approved than was spent in the 2008 actual year.

There was an overall increase in the period in the amount of $175,682.

This amount reflects the write-offs of small balances (less than $100) and bankruptcies. In 2011, a GS>50 kW customer filed for bankruptcy.

An increase in bad debt expense also reflects the downturn in the economy experienced in 2008, as well as changes in the Board's requirements set out in the Distribution System Code for low income customers and deposit policies.

**5340–Miscellaneous Customer Accounts Expense ($126,692)**

$230,875 more was budgeted in the 2008 Board Approved than was spent in the 2008 actual year.

Supplies, contracted services and advertising costs resulted in a cost increase in the amount of $33,555.

Staffing costs related to staff development, phones and parking decreased by ($13,846).

Indirect costs for such services as finance, property, phone, human resources and I.T. decreased in the amount of ($34,201).

Another contributor to the variance is removal of the 10% mark-up which was no longer charged by the City from 2011 onward.

In terms of the remainder of the change in the account, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5605–Executive Salaries & Expenses $336,608**

$31,567 less was budgeted in the 2008 Board Approved than was spent in the 2008 actual year.

The salary and benefits for a senior staff member was reallocated from account 5610 to 5605. This is not an increased cost, but simply an account reclassification that resulted in more costs being booked to account 5605.

There was a $65,987 increase in wages and benefits which includes payment of unused vacation time and BPI paying for 100% of the costs for the Finance department.

There was a $152,382 increase in indirect costs related to staff in the Finance department and other senior staff members. These indirect costs include increases for property charges for the building in which staff offices are located and an increase in cost due to the change in BPI's capitalization policy and the inability to capitalize certain administrative and general costs.

There was a ($14,853) decrease to reflect removal of the mark-up which was no longer charged by the City from 2011 onward.

**5610–Management Salaries & Expenses ($277,913)**

$291,622 more was budgeted for in the 2008 Board Approved budget than was spent in the 2008 actual year.

As discussed above in account 5605, the salary and benefits for a senior staff member was reallocated from account 5610 to 5605. This is not a decrease in cost, but simply an account reclassification that resulted in less costs being booked to account 5610.

There is a $48,201 increase in salaries and benefits from 2011 to 2013 between the Metering, Regulatory and Administration and Finance departments. Please refer to the Employee Compensation section in Exhibit 4, Tab 2, Schedule 4 for further details.

**5615–General Administrative Salaries & Expenses ($81,707)**

$244,696 less was budgeted for in the 2008 Board Approved budget than was spent in the 2008 actual year.

There was a ($291,607) decrease in the account. The main component of the decrease is that the City Treasury services and BPI Finance which were previously booked into this account are now being allocated across different accounts to various departments.

In addition to this, Legal Services which were also previously booked to this account are now being allocated to account 5630, Outside Services instead.

This decrease also reflects the retirement of an employee in the Administration area and this position was not replaced.

A ($31,282) decrease in this account is related to the removal of the mark-up which was no longer charged by the City from 2011 onward.

**5635–Property Insurance $133,133**

This variance is due to the fact that there were no funds booked to this account in the 2008 Board Approved budget. The variance between the 2013 Test Year and the 2008 actual spending was below the materiality threshold.

**5665–Miscellaneous General Expenses ($173,749)**

$12,531 less was budgeted for in the 2008 Board Approved budget than was spent in the 2008 actual year.

2008 includes $176,889 for holding company charges that were removed from the 2013 budget.

## 2011 ACTUAL – 2013 TEST YEAR

**5010–Load Dispatching $82,827**

The Engineering department increased the budget to reflect a $30,267 increase in salaries and benefits as well as the repurposing of a new position. Further details on Employee Compensation can be found in Exhibit 4, Tab 2, Schedule 5 in the Employee Compensation section.

Maintenance services for SCADA amounted to $11,810 and contracted services to provide SCADA support resulted in an increase of $15,000.

$2,264 is a result of an increase in monthly payments to Hydro One and $23,845 is an increase in indirect allocations due to higher wages and the change in BPI's capitalization policy in 2013.

**5065–Meter Expense $229,321**

There was an increase in the amount of $112,098 due to the change in the capitalization policy, which resulted in higher OM&A costs in 2013.

With the operationalization of smart metering in 2012, OM&A costs previously recorded in USoA account 1556, were booked to this account causing increases. There was an increase in the amount of $139,440 for contracted services for Smart Meter OM&A which includes Sensus Tower Gateway Base Station and Savage Operational Data Storage

**5085–Miscellaneous Distribution Expense $146,386**

There was a $54,991 increase in salaries and benefits in the Engineering and Operations departments. Please see the Employee Compensation section at Exhibit 4, Tab 2, Schedule 5 for further details.

Computer maintenance fees, mainly for the Integraph system, increased by $15,372. There was a $12,650 increase in contracted services for support on Asset Management and the ESA Audit. A $66,815 increase in costs is due to BPI's change in capitalization policy in 2013.

**5105–Maintenance Supervision & Engineering $192,113**

The majority of the variance amount is due to a change in account classification. Historically the Supervision costs for certain Engineering staff were allocated to account 5005. In 2012, the employee had only 3 months' worth of these costs allocated to account 5005 and the remaining 9 months were allocated to account 5105

$4,850 for staff development, meals, travel and memberships for Engineering were allocated to this account for 2012 and $0 for 2011.

An $81,401 increase in costs is due to BPI's change in capitalization policy.

**5135–Overhead Distribution Lines & Feeders – Right of Way $150,993**

There was an $8,387 increase in salaries and benefits. Forestry services increased by approximately $100,000 and costs increased by $100,131 due to BPI's change in capitalization policy.

**5160–Maintenance of Line Transformers $124,272**

The cost increase is due to the replacement of failed line transformers. In 2012, BPI replaced almost two times the normal number of transformers with larger, more expensive transformers. The increase in work resulted in higher labour costs in 2012 but was back to more usual levels in 2013. Between 2011 and 2013, labour costs decreased by ($1,221).

Inventory costs spiked in 2012 and again returned to more normal levels in 2013. The variance between 2011 and 2013 is an increase in the amount of $90,648.

Other costs related to staffing and rental equipment decreased by ($4,643) over the period and indirect costs related to General and Administrative costs charged under the SSA increased by $39,817.

**5305–Supervision $131,046**

There was an increase in salary and benefits in the Metering and Settlement department for a Supervisor role promoted in 2011.

The majority of the salary and benefits for the Supervisor of the Metering and Settlement department, $94,138, is now being allocated to account 5305, whereas before part of the salary and benefits were mostly allocated to accounts 5065 and 5310.

Also in Customer Services, the Supervisor was reclassified as a Manager. Please refer to the discussion of the 5300 account series in Exhibit 4, Tab 2, Schedule 4.

An increase of $49,451 was a result of the change in BPI's capitalization policy.

There was a decrease in the amount of ($6,696) related to staffing costs such as staff development, phones and parking.

Indirect costs related to General and Administrative expenses charged under the SSA decreased by ($11,708).

**5310–Meter Reading Expense ($113,866)**

Compensation decreased in the Metering and Settlement department by ($39,447). This decrease is a result of a change in account classification. As indicated in account 5305, the salary and benefits of the Supervisor role in the Metering and Settlement department was reallocated to account 5305, hence the decrease in account 5310. Also, 21% of the salary and benefits of two Settlement Officers and 10% of the salary and benefits of two Meter Technicians were allocated to this account from account 5065 and the Smart Meter Capital account.

Other expenses on the Metering and Settlement side include computer software and staffing costs at an increase of $8,838. There was also a cost decrease for contracted services and internal labour costs for conventional meter reading by ($34,437).

Cost for supplies, software and contracted services decreased in the amount of ($28,068) and staffing costs such as staff development, fleet and phones decreased by ($12,139).

The change in BPI's capitalization policy resulted in a cost increase of $44,429.

The indirect costs for Administrative and General expenses charged under the SSA were a decrease of ($22,493).

In terms of the remainder of the increase, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5315–Customer Billing $469,515**

On the Metering and Settlement side, there was an increase in compensation in the amount of $35,277. This increase is a result of a change in account classification. 25% of the salary and benefits of two Settlement Officers were reallocated to account 5315 from account 5065 and a Smart Meter Capital account, hence the increase in account 5315.

Changes to BPI's capitalization policy resulted in an increase of $174,262.

Other increased costs include postage, supplies (paper for bills) and equipment charges at an increase of $264,405.

Customer Service staffing costs, including staff development, phones and fleet costs decreased in the amount of ($31,654).

The indirect costs for Administrative and General expenses charged under the SSA decreased in the amount of ($58,011).

In terms of the remainder of the increase, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5320–Collecting $213,843**

Bank service charges for a drop box increased by $25,000.

Staffing costs such as staff development, fleet costs and phones decreased by ($12,002).

An increase of $93,603 was a result of the change in BPI's capitalization policy.

Indirect costs for Administrative and General expenses decreased in the amount of ($27,360).

In terms of the remainder of the increase, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5340–Miscellaneous Customer Accounts Expense $119,359**

Supplies, contracted services and advertising costs resulted in a cost increase in the amount of $33,555.

Staffing costs related to staff development, phones and parking decreased by ($13,846).

Indirect costs for Administrative and General expenses charged under the SSA decreased in the amount of ($34,201).

In terms of the remainder of the increase, some of the changes to specific 5300 series of accounts from 2011 to 2013 are the result of reclassifications and reallocations of costs. For further details, please refer to the discussion of the 5300 series of accounts at Exhibit 4, Tab 2, Schedule 4.

**5605–Executive Salaries & Expenses $409,728**

The salary for a senior staff member was reallocated from account 5610 to 5605. This is not an increased cost, but simply an account reclassification that resulted in more costs being booked to account 5605.

There was a $65,987 increase in wages and benefits which includes payment of unused vacation time and BPI paying for 100% of the costs for the Finance department.

There was a $152,382 increase in indirect costs related to staff in the Finance department and other senior staff members. These indirect costs include increases for property charges for the building in which staff offices are located and an increase in cost due to the change in BPI's capitalization policy and the inability to capitalize certain administrative and general costs.

**5610–Management Salaries & Expense $81,795**

There is a $48,201 increase in salaries and benefits from 2011 to 2013 between the Metering, Regulatory and Administration and Finance departments. Please refer to the Employee Compensation section in Exhibit 4, Tab 2, Schedule 5 for further details.

Indirect costs allocated increased by $35,438 for General and Administrative costs charged under the SSA.

**5615–General Administrative Salaries & Expense ($301,754)**

There was a ($291,607) decrease in the account. The main component of the decrease is that the City Treasury services and BPI Finance which were previously booked into this account are now being allocated across different accounts to various departments.

In addition to this, Legal Services which were also previously booked to this account are now being allocated to account 5630, Outside Services instead.

This decrease also reflects the retirement of an employee in the Administration area and this position was not replaced.

A ($31,282) decrease in this account is related to the removal of the mark-up which was no longer charged by the City from 2011 onward.

**5630–Outside Services Employed $92,285**

This account includes $100,000 for a Systems Integration Study as discussed in Exhibit 4, Tab 2, Schedule 3. In keeping with BPI's corporate objective to leverage technology to achieve productivity improvements, the Systems Integration Study is designed to review BPI's requirements, systems and operations to recommend integration plans that will result in significant improvements to the organization's operational efficiencies. The outcome of the study is to provide BPI with a road map of its best options over a three-year period and five-year period for achieving improved organizational performance though process and systems integration including an understanding of the financial and manpower investment required to achieve the performance gains. The study will identify systems improvements and resource requirements that will require further OM&A expenditures over the next three to five years. BPI expects that the funds allocated to the study in 2013 will be redeployed to fund these subsequent investments.

**5665–Miscellaneous General Expenses ($153,286)**

BEC management fees of $160,000 were removed from the 2012 trial balance.

# EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS

BPI's compensation, pension and post-retirement benefits are discussed in this section. BPI advises that it does not have an incentive plan in place.

## Union

BPI has two groups of unionized staff. One group is represented by the International Brotherhood of Electrical Workers (IBEW) Union and the other group is under the Canadian Union of Public Employees (CUPE) contract. The IBEW contract expires on May 31st, 2013 and is currently being renegotiated. The CUPE agreement expired on March 31st, 2012 and has been renegotiated for a two year period from April 1, 2012 to March 31, 2014.

## Executive/Management

The Executive and Management compensation plan consists of salaries and benefits. The Management group excluding the CEO and staff Directors, is represented by an association known as the Brantford Power Professional and Administrative Employees Association (BPPAE). An agreement is in place between BPI and BPPAE for the period of April 1, 2012 to December 31, 2013. Each position within BPI has been placed on a salary grid. Each employee's placement within their respective range is reviewed based on performance and subject to an economic adjustment factor. BPI does not offer any incentive or bonus compensation.

## Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and a company-sponsored retirement plan. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and management employees.

All full time staff participates in the OMERS pension plan.

All full time staff participates in Post-Retirement Benefits. The accrued expense is based on an actuarial valuation. The latest copies of valuation are provided as Appendix A.

**Employee Compensation and Benefits**

The employee complement, compensation and benefit information is provided in Table 4.28 below. BPI has aggregated the Executive and Management categories together into the Management category in all years with the exception of 2013 – with the transfer of employees to BPI, the numbers of employees in each category are such that it is no longer necessary to combine the categories.

# Table 4.28 - Employee Compensation

## Appendix 2-K
## Employee Costs

| | Last Rebasing Year (2008 Board-Approved) | Last Rebasing Year (2008 Actuals) | 2009 Actuals | 2010 Actuals | 2011 Actuals | 2012 Bridge Year | 2013 Test Year |
|---|---|---|---|---|---|---|---|
| *Reporting Basis* | | CGAAP | CGAAP | CGAAP | CGAAP | CGAAP | CGAAP |
| **Number of Employees (FTEs including Part-Time)[1]** | | | | | | | |
| Executive | 1.18 | | | | | 5.55 | 5.00 |
| Management | 13.82 | 12.20 | 12.75 | 12.80 | 14.17 | 11.70 | 15.14 |
| Non-Union | 11.24 | 4.45 | 4.75 | 4.75 | 3.67 | 4.00 | 6.93 |
| Union | 45.63 | 39.12 | 39.35 | 39.40 | 39.00 | 34.81 | 43.12 |
| Total | 72 | 55.77 | 56.85 | 56.95 | 56.84 | 56.06 | 70.19 |
| **Number of Part-Time Employees** | | | | | | | |
| Executive | | | | | | | |
| Management | | | | | | | |
| Non-Union | | | | | | | |
| Union | 3.02 | 8.00 | 11.00 | 10.00 | 8.00 | 11.00 | 2.00 |
| Total | 3.02 | 8 | 11 | 10 | 8 | 11 | 2 |
| **Total Salary and Wages** | | | | | | | |
| Executive | | | | | | $ 712,228 | $ 642,510 |
| Management | $ 1,559,871 | $ 1,147,194 | $ 1,219,554 | $ 1,301,936 | $ 1,402,207 | $ 962,124 | $ 1,341,844 |
| Non-Union | $ 692,837 | $ 292,969 | $ 333,514 | $ 347,469 | $ 264,318 | $ 255,555 | $ 495,259 |
| Union | $ 2,539,737 | $ 2,196,881 | $ 2,329,720 | $ 2,413,326 | $ 2,480,547 | $ 2,235,145 | $ 2,807,591 |
| Total | $ 4,792,445 | $ 3,637,044 | $ 3,882,789 | $ 4,062,731 | $ 4,147,072 | $ 4,165,053 | $ 5,287,204 |
| **Current Benefits** | | | | | | | |
| Executive | | | | | | $ 130,294 | $ 127,278 |
| Management | $ 335,518 | $ 237,714 | $ 253,607 | $ 268,332 | $ 265,271 | $ 247,095 | $ 241,629 |
| Non-Union | $ 134,221 | $ 59,072 | $ 70,466 | $ 81,232 | $ 58,530 | $ 59,753 | $ 87,600 |
| Union | $ 579,203 | $ 474,509 | $ 537,308 | $ 579,923 | $ 573,342 | $ 568,262 | $ 597,699 |
| Total | $ 1,048,942 | $ 771,295 | $ 861,381 | $ 929,487 | $ 897,143 | $ 1,005,404 | $ 1,054,206 |
| **Accrued Pension and Post-Retirement Benefits** | | | | | | | |
| Executive | | | | | | $ 223,955 | $ 10,653 |
| Management | | | | | | $ 16,691 | $ 25,567 |
| Non-Union | | | | | | $ 6,955 | $ 10,653 |
| Union | | | | | | $ 54,400 | $ 61,128 |
| Total | $ 849,005 | $ 220,062 | $ 244,532 | $ 215,393 | $ 175,099 | $ 302,001 | $ 108,001 |
| | | | | | | | |
| Executive | $ - | $ - | $ - | $ - | $ - | $ 354,249 | $ 137,931 |
| Management | $ 335,518 | $ 237,714 | $ 253,607 | $ 268,332 | $ 265,271 | $ 263,786 | $ 267,196 |
| Non-Union | $ 134,221 | $ 59,072 | $ 70,466 | $ 81,232 | $ 58,530 | $ 66,708 | $ 98,253 |
| Union | $ 579,203 | $ 474,509 | $ 537,308 | $ 579,923 | $ 573,342 | $ 622,662 | $ 658,827 |
| Total | $ 1,897,947 | $ 991,357 | $ 1,105,913 | $ 1,144,880 | $ 1,072,242 | $ 1,307,405 | $ 1,162,207 |
| **Total Compensation (Salary, Wages, & Benefits)** | | | | | | | |
| Executive | $ - | $ - | $ - | $ - | $ - | $ 1,066,477 | $ 780,441 |
| Management | $ 1,895,389 | $ 1,384,907 | $ 1,473,161 | $ 1,570,268 | $ 1,667,478 | $ 1,225,911 | $ 1,609,040 |
| Non-Union | $ 827,058 | $ 352,042 | $ 403,980 | $ 428,701 | $ 322,848 | $ 322,263 | $ 593,512 |
| Union | $ 3,118,940 | $ 2,671,390 | $ 2,867,028 | $ 2,993,249 | $ 3,053,889 | $ 2,857,807 | $ 3,466,418 |
| Total | $ 6,690,392 | $ 4,628,401 | $ 4,988,702 | $ 5,207,611 | $ 5,219,314 | $ 5,472,457 | $ 6,449,411 |
| **Compensation - Average Yearly Base Wages** | | | | | | | |
| Executive | | | | | | $ 128,329 | $ 128,502 |
| Management | $ 1,559,871 | $ 94,031 | $ 95,651 | $ 101,714 | $ 98,928 | $ 82,032 | $ 88,648 |
| Non-Union | $ 692,837 | $ 64,479 | $ 70,214 | $ 73,112 | $ 71,971 | $ 62,948 | $ 71,418 |
| Union | $ 2,418,902 | $ 52,243 | $ 56,338 | $ 57,942 | $ 60,611 | $ 61,558 | $ 63,184 |
| Total | | $ 62,362 | $ 66,315 | $ 69,046 | $ 70,898 | $ 72,541 | $ 74,142 |
| **Compensation - Average Yearly Overtime** | | | | | | | |
| Executive | | | | | | $ - | $ - |
| Management | $ - | $ 1 | $ - | $ - | $ 5 | $ 201 | $ - |
| Non-Union | $ - | $ 1,357 | $ - | $ 40 | $ 116 | $ 940 | $ - |
| Union | $ 120,835 | $ 3,919 | $ 2,867 | $ 3,313 | $ 2,996 | $ 2,652 | $ 1,930 |
| Total | | $ 2,857 | $ 1,984 | $ 2,295 | $ 2,064 | $ 1,756 | $ 1,185 |
| **Compensation - Average Yearly Incentive Pay** | | | | | | | |
| Executive | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Management | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Non-Union | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Union | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Compensation - Average Yearly Benefits** | | | | | | | |
| Executive | | $ - | $ - | $ - | $ - | $ 63,829 | $ 27,586 |
| Management | $ 24,278 | $ 19,485 | $ 19,891 | $ 20,963 | $ 18,716 | $ 22,546 | $ 17,652 |
| Non-Union | $ 11,941 | $ 13,275 | $ 14,835 | $ 17,101 | $ 15,963 | $ 16,677 | $ 14,168 |
| Union | $ 12,693 | $ 12,131 | $ 13,655 | $ 14,720 | $ 14,702 | $ 17,887 | $ 15,279 |
| Total | $ 16,304 | $ 17,777 | $ 19,453 | $ 20,104 | $ 18,865 | $ 23,322 | $ 16,558 |
| | | | | | | | |
| **Total Compensation** | $ 5,841,387 | $ 4,408,339 | $ 4,744,170 | $ 4,992,218 | $ 5,044,215 | $ 5,472,457 | $ 6,449,411 |
| **Total Compensation Capitalized (CGAAP)** | | $ 590,036 | $ 581,488 | $ 797,582 | $ 797,414 | $ 755,903 | $ 872,991 |
| **Total Compensation Charged to OM&A (CGAAP)** | $ 5,841,387.00 | $ 3,818,302.73 | $ 4,162,681.58 | $ 4,194,635.90 | $ 4,246,800.74 | $ 4,716,554.34 | |

## List of Assumptions Used

The 2008 Board Approved amounts include estimates of FTE and salary and wages. These are illustrative numbers, calculated based on SSA billings and the best information available to BPI in 2008. Except for those functions that were transferred to BPI on April 1, 2012 that were shared services being Customer Services, Finance and Inventory Management, BPI has not included illustrative staffing and compensation analysis for other shared services for 2008 through to 2012.

The service provider's staffing resources that delivered those remaining services varied depending upon the service provider's operating activities at a given time and are not specifically identifiable. As well, the amount of time that the service provider's resources spent delivering services during that time period is not known. As a result, the 2008 Actual to 2012 Bridge Year compensation levels for those resources are indeterminable and have not been included in Table 4.28 (Appendix 2-K: Employee Costs) or in the compensation analysis.

With the renegotiated SSA effective January 1, 2013 and revised costing methodology, BPI has better information about resource inputs to services purchased from its affiliate, the City, and has included that information in the analysis of head count and compensation in 2013.

However, these FTE and compensation amounts are illustrative calculations, as it is early in the 4 year term of this renegotiated SSA.

The 2008 actual to 2012 actual data includes estimated time for some functions, which were shared services prior to the transfer of employees to BPI on April 1, 2012. These functions include Customer Services, Finance, and Inventory Management.

Analysis for the year 2012 is complicated by the transfer of employees to BPI from the City on April 1, 2012. As information from before this transfer is based on estimates of wages and FTEs paid through shared services costs, the overall levels of compensation and FTE count for 2012 are estimates.

2013 Test Year amounts include estimated amounts for services purchased through BPI's SSA with the City.

Conservation and Demand Management positions are included in the analysis of compensation and employee count which follows. The costs from these positions are not recovered through distribution rates.

For the Years 2008 to 2012, there were fewer than three employees in the Executive category. For these years the Executive and Management compensation, headcount and benefits are presented together. 2013 was the first full year in which there were more than 3 employees in the Executive category.

**Change in Employee Compensation**

**<u>2008 Board Approved vs. 2008 Actual</u>**

Comparison between 2008 Board Approved and 2008 Actual wages and FTE count is problematic. The Board approved amounts include BPI's one employee; City employees doing work exclusively for BPI, as well as an illustrative estimate for the wages and benefits paid to shared employees, through service fees from BPI's SSA with the City. The 2008 figures include only BPI's employee and certain departments: Operations, Metering, CDM, Engineering, Administration, Finance, Customer Services, Dispatch and Inventory Management. Any SSA charges are not included in 2008 Actuals.

The decrease in FTE count and associated compensation for each employee group [(2.8) Management/ Executive; (6.49) Non-Union; and(6.51) Union)] is therefore primarily driven by the inclusion of City FTEs performing work for BPI in the Board Approved figures, but not in 2008 Actuals.

## 2008 Actual vs. 2009 Actual

**Management and Executive:**

Change in FTE: +0.55

Change in Compensation: $ 88,254

The change in management FTEs between 2008 and 2009 is associated with the hiring of a Customer Services Supervisor in July 2009 (an overlap in the function, in anticipation of a 2010 retirement) as well as the addition of a position in the Finance Department for a Senior Financial Analyst in June. These positions were shared positions, with each 60% allocated to BPI. The change in compensation can be attributed to these changes in FTE count, as well as a vested sick leave payout in 2009 and a step increase to an employee in the management category. The annual economic adjustment for non-union and management employees in 2008 was 3%, effective January 1.

**Non-Union:**

Change in FTE: +0.3

Change in Compensation: $51,938

The change in the FTE count for non-union employees can be explained by the resignation of a Financial Analyst in September 2008 ( a position 60% allocated to BPI), which is offset by a new hire of a Settlement, Energy and Smart Metering Officer (SESMO (+.75FTE) in April 2009.

The change in wages can be attributed to the above changes in staffing and the reclassification of one employee from Junior Engineer to Electrical Engineer in March 2008. Additionally, several employees received step increases mid-2008 and in 2009 and all received the annual economic adjustment for 2009 which was 3%.

**Union:**

Change in FTE: +0.23

Change in Compensation: $195,639

Between 2008 and 2009 actuals, FTE count increased by 0.23 FTEs. A Meter Technician, hired in September 2008 to replace a retirement in July 2008, created some decrease due to the gap between the departure of the retiree and the commencement of the new employee. A new Linesperson was hired in October 2008, causing an increase in FTE and salary between 2008 and 2009. A new hire for a Conservation Program Adviser in May 2008 similarly created an increase. The Operations Department hired an additional student in 2009 and Customer service had a student as well (allocated at 60% to BPI) in 2009.

The increase in compensation is caused by more than the changes in staffing levels. Between 2008 and 2009, there were several reclassifications and step increases in the Union category. In particular, in Operations in 2008 two Apprentices were promoted to Linesperson/Journeyperson, while three others were reclassified to a higher class of Apprentice. In 2009, there were three more reclassifications to a higher class of Apprentice. Each of these changes had an accompanying change in wages. Several Engineering Department employees received step increases in 2008 and 2009.

The amount of overtime paid to the union group decreased by $40,492 between 2008 and 2009.

The annual economic adjustment for IBEW employees in 2009 was 3%. The annual economic adjustment for CUPE employees for 2009 was 2%.

**Management and Executive:**

Change in FTE: +0.05

Change in Compensation: $97,106

FTE increased over 2009 due to two positions hired in 2009 which contributed a full year's wages and FTE in 2010. Both positions were hired mid-year and each was allocated 60% to BPI. The increases from these positions were almost fully offset by a decrease in Customer Services Management staff, due to a retirement at the end of 2009, in a position allocated 60% to BPI.

Between 2009 and 2010 there was an increase to the compensation paid to the management group in addition to the increase as a result of the staffing changes described above. This compensation increase was the result of BPI's introduction of the On-Call Policy for Exempt Staff in October 2009, allowing compensation of non-union employees for performing on-call duties. This resulted in an increase in compensation, as several employees in the management category had on-call responsibilities.

The remaining increase can be explained by the annual economic adjustment for non-union employees, which was 3% in 2010.

**Non-Union:**

Change in FTE: 0

Change in Compensation: +$24,721

The variance in the Non-Union FTE count between 2009 and 2010 is zero. Several changes occurred in the Metering and Settlement Department, which altogether constituted this variance, including an increase from a newly hired SESMO in April 2009, contributing the full year in 2010. There was a retirement at the end of 2009, contributing decrease of 1FTE. A replacement was in this position from January to April, followed by some gap time; the position was filled again in June 2010. The change in wages is explained by these changes, as well as the economic adjustment applied to all non-union wages in 2010. The annual economic adjustment for non-union employees in 2010 was 3%.

**Union:**

Change in FTE: 0.05

Change in Compensation: $126,221

The increase in union FTE between 2009 and 2010 is caused by the return to work in August 2010 of an employee in the Customer Services department. This was offset partially a decrease due to gap time between a resignation at the end of 2009 and a replacement hire in April 2010 in the Customer Services Department.

Despite a decrease in FTE count, compensation paid increased. There were several step increases and reclassifications in 2010, resulting in pay increases. These included the reclassification of an AM/FM Specialist to Electrical Design Technologist, as well as the promotion of 2 Apprentices to Linesperson, and one Apprentice class change. Further, overtime pay increased between 2009 and 2010 by $16,854.

The annual economic adjustment for IBEW and CUPE employees in 2010 was 2%.

## 2011 Actual vs. 2010 Actual

**Management and Executive:**

Change in FTE: +1.37

Change in Compensation: $97,210

The increase in FTE between 2010 and 2011 can be attributed to: the reclassification of two positions (both previously in the Non-Union category) into Management positions in 2011 (+2FTE); one new hire for a CDM Manager in May 2010 (+.5FTE); the departure without replacement at the end of January 2011 of the Chief Operating Officer (-.92 FTE): and a decreased allocation of the CFO’s time to BPI (-.21 FTE). The reclassifications described above were the promotion of a Regulatory Analyst to Senior Regulatory Analyst and the promotion of one SESMO to Supervisor of Smart Metering and Settlement.

The increase to wages is the impact of the above staffing changes to salaries, as well as economic adjustment for the year.

The annual economic adjustment for non-union employees in 2011 was 3%.

**Non-Union:**
Change in FTE: -1.08
Change in Compensation: -$105,853

In 2011, two non-union employees were reclassified to the management category, resulting in a 2 FTE decrease in the non-union category. A June 2010 hire in the Metering and Settlement department caused an increase as the full salary and FTE came into place for 2011. The hiring of a Regulatory Analyst in July 2011 brought the total FTE decrease to (1.08).

The decrease in compensation paid represents the FTE changes described above, offset in part by the annual economic adjustment for non-union employees in 2011, which was 3%.

**Union:**
Change in FTE: -0.40
Change in Compensation: $60,640

Part of the decrease in FTE between 2010 and 2011 is due to a gap between the resignation of a AM/FM Specialist & CADD Coordinator at the end of 2010 and the hiring of a replacement in March 2011. The resignation of a CDM adviser in August represents another decrease in 2011. The April 2010 hire of a Customer Premise Representative allocated 60% to BPI contributes an increase to the FTE count for 2011, as the position was unfilled for a portion of 2010. In Customer Services, in there was a part time CSR hired in January 2011, and the reclassification from part time to full time in June 2011 of another CSR. Both of these positions in Customer Services were allocated at 60% to BPI.

Despite a decrease in FTE count, there was an increase in wages paid to the union category. In Operations, three Apprentices were promoted to Linesperson late within 2010 and in 2011. These reclassifications had no impact on FTE count but did impact wages.

There was an increase from overtime paid to the union group of $64,873 from 2010 to 2011. The annual economic adjustment for 2011 for IBEW and CUPE employees was 2%.

**2012 Bridge vs. 2011 Actual**

**Management and Executive:**
Change in FTE: 3.08
Change in Compensation: $384,264

In April 2012, three Engineering Department positions (two previously in the union category and one in non-union) were reclassified as management positions, resulting in a significant increase in compensation for the Management and Executive group. The reclassifications were: Electrical Engineer to Manager of Systems and Standards; Senior Distribution Designer to Supervisor of Design and Construction; and Electrical Planning and Control Technologist to Supervisor of SCADA, DG and Smart Grid. Additionally, for the year 2012, the CFO's time was allocated 75% to BPI, representing a .25 FTE increase from the allocation of 50% in 2011. Two other management positions which were shared positions were allocated at different percentages to BPI. The Director of Regulatory Affairs/Board Secretary had previously been allocated 70% to BPI and was allocated at 80% for 2012. The Senior Financial Analyst had been allocated to BPI at 60% and became 100% after April 2012. One other Senior Financial Analyst remained with the City after April 2012. Similarly, the Supervisor of Customer Services which had been allocated at 60% became allocated at 100% after April 2012, but the Manager of Customer Services remained with the City.

In addition, there is a temporary decrease from a maternity leave in the Regulatory department, offset by a contract hire (in the non-union category) to backfill in the same department in December 2011.

The change in wages between 2011 and 2012 can be attributed to the FTE level changes as described above, in addition to economic adjustments.

The annual economic adjustment for non-union employees in 2012 was forecast to be 1.25%, effective April 1.

**Non-Union:**
Change in FTE: +0.33
Change in Compensation: -$7,540

The change in the FTE count for non-union FTEs was +0.33 between 2011 and 2012. In July 2011 there was a new hire of a Regulatory Analyst, which contributed a full FTE in 2012. Similarly a Regulatory Analyst contract, hired in December 2011, contributed a full FTE. These increases were partially offset by the reclassification of one Electrical Engineer to the position of Manager, Systems and Standards, a change from the non-union category to the management category.

The change in compensation is related to the change in FTE count described above.

In addition, the annual economic adjustment for non-union employees in 2012 was forecast to be 1.5%.

**Union:**
Change in FTE: -4.19
Change in Compensation: -$250,482

Between 2011 and 2012, two positions in Engineering, previously in the union category, were reclassified as non-union positions. In Operations, one Linesperson was reclassified to fill the Foreperson (a management role) left open due to a retirement. BPI did not hire a replacement Linesperson in 2012, decreasing the union FTE count by 1.

In Engineering, there was a decrease resulting from a temporary overlap in 2011 between an AM/FM Specialist/CADD Coordinator retiring in September 2011 and a replacement hire in May 2011. As there was only one FTE in this position for 2012 and no overlap, this was a reduction of (0.32) FTE.

One employee retired in March 2012 from a Customer Premise Representative position, allocated to BPI at 60%. This position was repurposed within the Customer Services department to a Customer Service Representative position, allocated 100% to BPI as it was after the transfer of employees. This new position was filled in May 2012. There was a small increase to FTE count from this change, as the change from 0.6 to 1 FTE was partially offset by the gap time between the retirement and new hire (+0.11 FTE).

Another small variance came as a result of a new AM/FM Specialist/ CADD Operator hire in June 2011, which resigned in August 2012, and was replaced in October 2012. The overall increase in this position from 2011 to 2012 was 0.42 FTE.

There was a resignation in the CDM group in August 2011, replaced in April 2012. This had a +0.08 FTE impact, as the position was filled for longer in 2012 than it was in 2011.

The transfer of employees in April 2012 impacted the departments with shared positions. Each of the union positions which were previously shared allocation was allocated 100% to either the City or to BPI after April 1 2012. The affected departments were Customer Services, Finance and Inventory Management. The net impact to BPI union FTE count as a result of the transfers in these departments was (2.45) FTE. There was a (2.3) decrease in the number of Customer Services FTEs, a (0.3) FTE decrease in Finance, and an increase of 0.15 FTE in Inventory Management. BPI was transferred two Customer Services positions which were vacant in 2012, as well as one in Finance.

There was a reduction to Administrative positions in April, decreasing FTE count compared to 2010 by (0.75). The hire of a temporary Junior Financial Analyst contract in 2012 contributed an increase to FTE count by 0.5, as well as the following hires in Customer Services: one new full time hire in August 2012; one CSR contract hired in November; and one part time CSR in December 2012.Overall the new Customer Services hires increased FTE count by 1.22.

The decrease in Union compensation in 2012 compared to 2011 can be attributed to the decreases in staffing as described above. Additionally, the Annual the annual economic adjustment for non-union employees in 2012 was 1.25%

**2013 Test vs. 2012 Bridge**

**Executive:**

Change in FTE: -0.55

Change in Compensation: - $72,734

There is a decrease of (0.55) FTE in the executive category between bridge and test year. There were increased in the allocations of two positions to BPI – specifically, the CFO was allocated 100% to BPI for the first time compared to 2012 when the allocation had been 75%. Similarly, the Director of Regulatory Affairs had been allocated only 80% to BPI in 2012 and is allocated 100% to BPI for 2013. However, there is an offsetting reduction of 1 FTE, representing the retirement in 2013 of the Director of Operations, whose responsibilities were absorbed within the existing executive group, creating an overall reduction in FTE.

There was a decrease in wages paid to this category reflecting the reduced headcount. There is also some offsetting increase to salaries paid, reflecting the full allocation of some executive salaries in 2013 compared to partial allocation for the first quarter of 2012. Additionally, the annual economic adjustment forecast for 2013 was 1.25%.

**Management:**

Change in FTE: +0.3/ +3.44 with SSA estimate.

Change in Compensation: +$30,395/+$374,253 with SSA estimate

The 2013 Test Year includes a budget for one new Foreperson position, left vacant since a July 2012 retirement, representing a 0.5 FTE increase. A further increase was caused by the return from maternity leave of the Senior Regulatory Analyst in 2013. In addition to these changes, there is a decrease of 0.05 FTE from Customer Services. This small FTE amount represents the additional management hours worked in 2012 from having two Customer Services management positions, each allocated to BPI at 60%, for the first quarter of the year. After the employee transfer in April 2012, and going forward, there is only 1 Customer Services Supervisor at 100% BPI.

The above changes are partially offset by the re-categorization of one employee previously in the management category to non-union. There is a further decrease in 2013 compared to 2012 as a result of a Sr. Financial Analyst allocated at 60% to BPI until April 2012. This position was not transferred in April 2012 and does not contribute and FTE in 2013.

The change in FTEs increases to +3.44 taking into consideration the estimated allocation of 3.14 management FTEs in 2013 through the SSA with the City. The change in compensation is related to the staffing changes described above. Recognizing the estimated management group compensation costs allocated to BPI through its SSA with the City (of $343,858), the change in wages from 2012 becomes +$374,253. The management roles included in these FTE counts are functions including (but not limited to) Legal, Real Estate, and Human Resource Services, among others. Additionally, the annual economic adjustment forecast for 2013 was 1.5% for this employee group.

**Non-Union:**

Change in FTE: +1/+2.93 with SSA estimate

Change in Compensation: $105,952/ +267,551with SSA estimate

The increase in non-union FTE is due to one employee being reclassified to the non-union category from management. Additionally, an estimated 1.93 non-union employees are allocated to BPI through the SSA.

The change in wages can be attributed partly to the categorization change from management to non-union described above.

Through the SSA, it is estimated that BPI is allocated $161,599 in non-union compensation. This brings the total change in compensation between 2012 and 2013 to +$267,551. Additionally, the annual economic adjustment forecast for 2013 is 1.5% for this employee group.

**Union:**

Change in FTE: +3.84/+8.31 including SSA estimate

Change in Wages: +$266,054/ +$608,611 with SSA

For 2013, the level of services to be purchased through the SSA which will be performed by Union positions is estimated at 4.47 FTE. The estimated compensation associated with BPI's share of these positions is $342,557.

The remaining 3.84 FTE increase represents a multitude of small variations between 2012 and 2013. The test year budget includes the following union positions: a new Customer Service Representative position; a proposed new Financial Analyst position; and an Electrical Design Technologist position in Engineering. Together these new positions represent 2.7 FTE.

A net increase of 0.28 FTE is the result the transfer of employees in April 2012, when certain employees which were previously shared employees were either transferred to BPI or not transferred. Those who had been shared employees until April 2012 made some contribution towards the level of FTEs in 2012, but contributed 0 in 2013, creating a decrease. Those employees which were shared before April 2012, and subsequently allocated 100% of their time to BPI contributed less than a full employee for 2012, but contributed a full employee in 2013, for an increase. The net impact of these previously shared positions is a variance of 0.28 Union FTEs

Additionally, the union positions which were newly hired in 2012 contributed less than a full FTE in that year, depending on their date of hire. Each of these new hires contributed 1.0 FTE for 2013, for an increase over 2012 levels. The impact of these 2012 hires was +2.09 FTE. The positions included in this amount are the 2012 new hires discussed in the 2011 to 2012 Union Variance above.

There was a net increase of 0.53 employees resulting from positions in which there were resignations/retirements, and replacements in 2012. Details of these positions can also be found above in the 2011 to 2012 Union Variance Analysis.

There was a decrease in Administrative positions, resulting from one position not transferred in April 2012, and one retirement in 2013. This produces an overall decrease of 1.25 FTE between 2012 and 2013. A further decrease of 0.5 represents the end of a contract position in the Finance department in 2012.

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

## **<u>Change in Benefits</u>**

In 2011 OMERS released a 3-year plan indicating approximately 1% per year increase in OMERS premiums beginning in 2012. The expected increase for 2013 was confirmed by email to BPI on July 06 2012. The following is an excerpt from that email:

***OMERS 2013 Contribution Rates and Plan Changes Announced***

*On June 28, 2012, the OMERS Sponsors Corporation (SC) announced the 2012 Plan changes that were passed – from those that were proposed during the 2012 Specified Plan Changes cycle:*

- *A contribution rate increase for both members and employers, beginning in 2013. (This is the third of the three planned rate increases announced in 2010 as part of OMERS deficit reduction strategy.)*
- *A cap to the amount of contributory earnings that may be included for OMERS pension purposes.*

*Although not a Plan change, the SC also approved a new method for allocating contribution rate adjustments in the future, and the SC decided to file the December 31, 2011, actuarial valuations for the OMERS Primary Pension Plan (OMERS Plan) and Supplemental Plan (for police, firefighters and paramedics).*

***OMERS 2013 Contribution Rates***

*Contributions to the OMERS Plan are made by members and matched by employers. Along with investment earnings, contributions provide members with lifetime retirement income.*

*Contribution rate changes are effective with the first, full pay in 2013.*

*Contribution rates for normal retirement age 65 members.*

*On earnings up to CPP earnings limit*: 2012 is 8.3%; 2013 will be 9.0%.*

*On earnings over CPP earnings limit*: 2012 is 12.8%; 2013 will be 14.6%.*

*Contribution rates for normal retirement age 60 members.*

*On earnings up to CPP earnings limit*: 2012 is 9.4%; 2013 will be 9.3%.*

*On earnings over CPP earnings limit*: 2012 is 13.9%; 2013 will be 15.9%.*

**CPP earnings limit (Year's Maximum Pensionable Earnings or YMPE) in 2012 is $50,100; the limit in 2013 will be higher. OMERS members pay a lower rate of contributions on earnings up to the YMPE because OMERS and the CPP are designed to work together to provide pension benefits.*

This increase in OMERS pension costs has been included in the cost of current benefits in this application. The increases for 2012 and 2013 are compounded by general salary increases.

The amounts for current benefits paid include health, dental and other related insurance premiums, Employment Insurance, Employer Health Tax and Canada Pension Plan premiums. The largest component of these amounts is OMERS pension costs. Until 2013, BPI has paid these amounts in aggregate, as service fees to the City, for employees of the City doing work for BPI. As such, a separate figure for yearly OMERS costs paid is not available.

The current benefits amount for 2013 included in Table 4.28 above and Appendix K also includes an estimate of the benefits paid through BPI's SSA with the City. Table 4.29 below presents the amounts to be paid for BPI employees only.

To ensure all compensation components charged to OM&A have been represented in this Exhibit, BPI has included meal and mileage expense paid to employees under the current benefits section in Table 4.28 above and in Chapter 2 Appendix 2-K. The figures below are presented without these expenses.

**Table 4.29 - Current Benefits Paid**

| | 2008 Actual | 2009 | 2010 | 2011 | 2012 Bridge | 2013 Test |
|---|---|---|---|---|---|---|
| Current Employee Benefits | $755,639 | $856,592 | $905,925 | $994,275 | $ 1,014,381 | $ 1,025,425 |

## Post-Retirement Benefits - Liability

BPI has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year, in Table 4.30 below. For the years 2008-2011, the information is presented as a total amount, without being split by employee category. In these years, BPI had only one active employee, several retired employees (dating back to Brantford PUC) and paid post-retirement benefits premiums as service fees to the City for all other employees. As such, it is not possible to separate the post-retirement benefits liability by employee group.

## Post-Retirement Benefits - Premiums

BPI pays certain health, dental, and life insurance benefits on behalf of its retired employees. Actual premiums paid for 2009 Actual, 2010 Actual, 2011 Actual, 2011 Actual, 2012 Bridge Year, and 2013 Test Year, are shown in Table 4.30 below.

For the 2012 Bridge Year and the 2013 Test Year, no amounts have been included in OM&A for Post-Employment Benefit Obligation. BPI is proposing to track future fluctuations in actuarial value through a Deferral and Variance Account. As these amounts do not impact OM&A spending on compensation, they have not been included in Table 4.30 or Appendix 2-K in this Exhibit. Please refer to the discussion of the Request for Accounting Order in Exhibit 9, Tab 2, Schedule 5.

**Table 4.30 - Post-Retirement Benefit Information**

| Components | 2008 Actual | 2009 | 2010 | 2011 | 2012 Bridge | 2013 Test |
|---|---|---|---|---|---|---|
| Post-Employment Premiums Paid | $ 115,995 | $ 127,702 | $ 115,859 | $ 94,547 | $ 85,000 | $ 108,000 |
| Change in Post - Employment Benefit Obligation | $ 104,067 | $ 116,830 | $ 99,534 | $ 80,552 | | |
| Reconciliation of Monies Due on Retirement | | | | | $ 217,000 | |
| **Total: Post-Employment Benefit Expense** | **$ 220,062** | **$ 244,532** | **$ 215,393** | **$ 175,099** | **$ 302,000** | **$ 108,000** |

BPI participates in a joint tendering process approximately every three years with the City to obtain actuarial services required for the respective organizations. The two organizations issued a request for proposal for the appointment of actuaries for the 2012 requirements. The successful proponent was Morneau Shepell.

Prior to the completion of this process, BPI recognized that the 2012 restructuring resulting in the transfer of employees from the City to BPI would result in BPI being required to assume the obligations for Employee Future Benefits for those eligible employees transferred. As the majority of employee transfers occurred on April 1, 2012, BPI needed to determine the value of this assumed obligation in a timely fashion. It was not possible to extract the value of such Employee Future Benefit obligations from the City’s Employee Future Benefit Obligations as those obligations are calculated pursuant to Public Sector Accounting Standards. Furthermore, the transferred employees represented a very small proportion of the City’s Employee Future Benefits.

Recognizing that this obligation would result in a transaction to BPI's shareholder's equity, BPI needed to establish in a timely manner how this transaction would impact BPI's Balance Sheet. This was essential to determine if this transaction would result in BPI breaching any of its existing credit facility covenants. As BPI is obligated to confirm to its financiers on a quarterly basis that it is in compliance with its covenants, it was not possible or prudent to wait for the appointment of new actuaries to determine this impact. Consequently, the incumbent actuaries were asked to update the previous actuarial reports to reflect the impact of the 2012 restructuring transaction. Dion Durrell produced this report to establish the valuation of the Employee Future Benefit obligations assumed by BPI due to the restructuring transaction.

At the fiscal year end, the Company's new Actuaries reviewed this information and relied on the Dion Durrell report as an input to their preparation of their full updated actuarial valuation for BPI. The resulting information from Morneau Shepell was reflected in 2012 audited financial statements.

BPI has included both actuarial reports below.

# APPENDIX A

# ACTUARIAL EVALUATION DRAFT POST-RETIREMENT BENEFIT REPORTS

Dion Durrell
Actuaries and Consultants

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# BRANTFORD POWER INC.

## REPORT ON THE ACTUARIAL VALUATION OF POST-RETIREMENT NON-PENSION AND VESTED SICK LEAVE BENEFITS

**As At January 1, 2012 and April 1, 2012**

**FINAL — November 15, 2012**

Dion Durrell

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# EXECUTIVE SUMMARY

## PURPOSE

MEARIE Actuarial Services and Dion, Durrell + Associates Inc. were engaged by Brantford Power Inc. (the "Corporation") to perform an actuarial valuation of the post-retirement non-pension and vested sick leave benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2012. The nature of these benefits is defined benefit.

This report is prepared in accordance with guidelines set forth in Section 3461 Employee Benefits of the CICA Handbook Accounting Part V Pre-Changeover Accounting Standards ("CICA Section 3461"). The most recent full valuation was prepared as at January 1, 2008 based on the then appropriate assumptions.

The Corporation has indicated that effective January 1, 2012, 1 employee of the City of Brantford was transferred to the Corporation and effective April 1, 2012, an additional 51 employees were transferred to the Corporation. Furthermore, the Corporation will assume all post-retirement non-pension and vested sick leave benefit liabilities for the transferred employees, inclusive of past service and future service accrued benefits. We understand that, pursuant to CICA guidelines, the impact of the past service liability for the transferred employees will be fully recognized on the Corporation's balance sheet at January 1, 2012 and April 1, 2012.

The purpose of this valuation is:

i) to determine the Corporation's liabilities in respect of post-retirement non-pension and vested sick leave benefits at January 1, 2012, and to determine the liabilities at January 1, 2012 and April 1, 2012 for the employees transferring to the Corporation from the City of Brantford;

ii) to determine the benefit expense for fiscal year 2012; and

iii) to provide all other pertinent information necessary for compliance with CICA Section 3461.

The intended users of this report include the Corporation and their auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

## SUMMARY OF KEY RESULTS

The key results of this actuarial valuation, including both post-retirement non-pension and vested sick leave benefits, as at January 1, 2012 and April 1, 2012 with comparative results from the previous valuation as at January 1, 2008 are shown below:

| | January 1, 2008 ($000s) | January 1, 2012 ($000s) | April 1, 2012 ($000s) |
|---|---|---|---|
| Accrued Benefit Obligation (ABO) | | | |
| a) People in receipt of benefits | 1,423 | 897 | - |
| b) Fully eligible actives | 111 | 107 | 452 |
| c) Not fully eligible actives | - | 27 | 797 |
| **Total ABO** | **1,534** | **1,031** | **1,249** |
| Current Service Cost: *for 2008 and 2012* | - | 4 | 71 |
| Prepaid Benefit Liability: *at January 1* | | 977 | |

The January 1, 2012 Prepaid Benefit Liability is based on extrapolations of the January 1, 2008 valuation results to December 31, 2011.

The January 1, 2012 results include 1 employee who transferred from the City of Brantford to the Corporation.

The April 1, 2012 valuation results are in respect of the 51 employees who transferred from the City of Brantford to the Corporation. The Corporation has assumed the post-retirement non-pension and vested sick leave benefit liabilities for these employees from the City of Brantford for all past and future service.

Dion Durrell

## ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension and vested sick leave benefit plans sponsored by the Corporation as at January 1, 2012 and April 1, 2012 (for transferred employees), for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;

2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations), and we have reviewed the assumptions and consider them to be appropriate for the purposes of the valuation outlined herein;

3. The actuarial methods employed, as outlined in Section C, are appropriate for the purpose and consistent with sound actuarial principles;

4. All known substantive commitments with respect to the post-retirement non-pension and vested sick leave benefits sponsored by and identified by the Corporation are included in the calculations; and

5. The valuation conforms to the standards set out in the Canadian Institute of Chartered Accountants Accounting Handbook Section 3461.

We are not aware of any subsequent events from April 1, 2012 up to the date of this report that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is January 1, 2015. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

**DION, DURRELL + ASSOCIATES INC.**

Stanley Caravaggio

**Stanley Caravaggio FSA, FCIA**

Patrick G. Kavanagh

**Patrick G. Kavanagh ASA**
Actuarial Analyst

Toronto, Ontario
November 15, 2012

# SECTION A— VALUATION RESULTS

Table A.1 shows the key valuation results for the prior valuation.

Table A.2 shows the key valuation results for the current valuation.

Table A.3 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 59 to 57, and an increase/decrease in the health and dental claims cost trend rates by 1% per annum.

Table A.4 presents the determination of the actuarial gain/(loss) from the previous valuation at January 1, 2008.

## VALUATION RESULTS

**Table A.1—Valuation Results for Prior Valuation**
**(in thousands of dollars)**

| | January 1, 2008 Post-Retirement | Sick Leave | Total |
|---|---|---|---|
| 1. Accrued Benefit Obligation | | | |
| a) People in receipt of benefits | 1,423 | - | 1,423 |
| b) Fully eligible actives | 43 | 68 | 111 |
| c) Not fully eligible actives | - | - | - |
| **Total ABO** | **1,466** | 68 | **1,534** |
| 2. Benefit Expense | | | |
| a) Current Service Cost | - | - | - |
| b) Interest Cost | 80 | 4 | 84 |
| c) Expected Return on Assets | - | - | - |
| d) Amortization of Transition Amount | - | - | - |
| e) Amortization of Past Service Cost | - | - | - |
| f) Amortization of (Gain)/Losses | 51 | 4 | 55 |
| **Total Benefit Expense** *for following 12 months* | **131** | 8 | **139** |
| 3. Benefit Payments *for following 12 months* | 33 | - | 33 |

**Table A.2—Valuation Results for Current Valuation**
**(in thousands of dollars)**

**Existing members and 1 transferred employee from the City of Brantford at January 1, 2012**
**January 1, 2012 – December 31, 2012**

| | January 1, 2012 | | |
|---|---|---|---|
| | **Post-Retirement** | **Sick Leave** | **Total** |
| 1. Accrued Benefit Obligation | | | |
| a) People in receipt of benefits | 897 | - | 897 |
| b) Fully eligible actives | 29 | 78 | 107 |
| c) Not fully eligible actives | 27 | - | 27 |
| **Total ABO** | **953** | **78** | **1,031** |
| 2. Benefit Expense (January 1, 2012 – December 31, 2012) | | | |
| a) Current Service Cost | 4 | - | 4 |
| b) Interest Cost | 31 | 3 | 34 |
| c) Expected Return on Assets | - | - | - |
| d) Amortization of Transition Amount | - | - | - |
| e) Amortization of Past Service Cost | - | - | - |
| f) Amortization of (Gain)/Losses | - | - | - |
| **Total Benefit Expense** *for 2012* | **35** | **3** | **38** |
| 3. Benefit Payments *for 2012* | 88 | - | 88 |

**51 transferred employees from the City of Brantford at April 1, 2012**

| | April 1, 2012 Post-Retirement | Sick Leave | Total |
|---|---|---|---|
| 1. Accrued Benefit Obligation | | | |
| a) People in receipt of benefits | - | - | - |
| b) Fully eligible actives | 348 | 104 | 452 |
| c) Not fully eligible actives | 738 | 59 | 797 |
| **Total ABO** | **1,086** | **163** | **1,249** |
| 2. Benefit Expense (April 1, 2012 – December 31, 2012) | | | |
| a) Current Service Cost | 69 | 1 | 70 |
| b) Interest Cost | 27 | 5 | 32 |
| c) Expected Return on Assets | - | - | - |
| d) Amortization of Transition Amount | - | - | - |
| e) Amortization of Past Service Cost | - | - | - |
| f) Amortization of (Gain)/Losses | - | - | - |
| **Total Benefit Expense** *for April 1, 2012 – December 31, 2012* | **96** | **6** | **102** |
| 3. Benefit Payments *for 2012* | - | - | - |

## SENSITIVITY ANALYSIS

**Table A.3—Sensitivity Analysis**
**(in thousands of dollars)**

| | Valuation Results | Retirement Age 57 | 1% Higher Trend | 1% Lower Trend |
|---|---|---|---|---|
| 1. Accrued Benefit Obligation at April 1, 2012 | | | | |
| a) People in receipt of benefits | 899 | 899 | 931 | 869 |
| b) Fully eligible actives | 560 | 607 | 574 | 549 |
| c) Not fully eligible actives | 825 | 989 | 916 | 696 |
| **Total ABO** | **2,284** | **2,495** | **2,421** | **2,114** |
| 2. Current Service Cost *for 2012* | 75 | 94 | 87 | 64 |
| 3. Interest Cost *for 2012* | 66 | 71 | 70 | 61 |
| 4. Expected Average Remaining Service Lifetime of the Current Active Employees (years) | 12 | 11 | 12 | 12 |

For simplicity, the sensitivity analysis above is based on the Accrued Benefit Obligation calculated as at April 1, 2012. The ABO at April 1, 2012 is equal to the ABO at January 1, 2012 projected forward to April 1, 2012 for all employees.

## DEVELOPMENT OF NET GAINS OR LOSSES

**Table A.4—Development of Net Gains or Losses**
**(in thousands of dollars)**

| | |
|---|---|
| Expected ABO at December 31, 2011 | 1,763 |
| Actual ABO at January 1, 2012* | 1,004 |
| Actuarial Loss/(Gain) at January 1, 2012 | (759) |
| **Amortization of Unamortized Actuarial Loss** | |
| Unamortized Net Actuarial Loss (Gain) at December 31, 2011 | 787 |
| Actuarial Loss (Gain) for Current Year at January 1, 2012 | (759) |
| Total Loss (Gain) at January 1, 2012 | 28 |
| *Less:* Actual Amortization for 2012 | - |
| Expected Unamortized Actuarial Loss (Gain) at December 31, 2012 | 28 |

* Excludes the liability for the 1 employee who transferred to the Corporation from the City of Brantford at January 1, 2012.

Please note that the actual ABO at January 1, 2012 is approximately $759,000 lower than the expected ABO at March 31, 2012. This is due to a combination of the following factors:

- A change in the health claims cost trend rate assumption (an increase of approximately $18,000).
- A change in the dental claims cost trend rate assumption (an increase of approximately $5,000).
- Differences between the actual and expected dental benefit cost rates (a decrease of approximately $26,000).
- Differences between the actual and expected health benefit cost rates (a decrease of approximately $610,000).
- Deviations from the expected demographic changes of the valued group and other miscellaneous factors (a decrease of approximately $146,000 in the total ABO).

CICA Section 3461 states that any gain or loss in excess of 10% of the ABO must, at minimum, be amortized over the expected average remaining service lifetime ("EARSL"). The EARSL of the current active group is 11 years. Under these guidelines, there is no required amortization for the year 2012.

**Transfer of Liability from the City of Brantford**

The Corporation has indicated that effective January 1, 2012, 1 employee, and effective April 1, 2012, 51 employees were transferred to the Corporation from the City of Brantford. The Corporation will assume all post-retirement non-pension and vested sick leave benefit liabilities for the transferred employees, inclusive of past service and future service accrued benefits. The accrued benefit obligation for the transferred employees is approximately $27,000 and $1,249,000, respectively, as at January 1, 2012 and April 1, 2012. We understand that, pursuant to CICA guidelines, the impact of the liability for the transferred employees will be fully recognized on the Corporation's balance sheet at each date.

# SECTION B— PLAN PARTICIPANTS

Table B.1 sets out the summary information with respect to the plan participants valued in the post-retirement non-pension benefits valuation, along with comparisons to the participants in the previous valuation at January 1, 2008.

Table B.2 reconciles the number of post-retirement non-pension benefits participants in the last valuation to the number of participants in the current valuation.

Table B.3 sets out summary information with respect to the plan participants valued in the vested sick leave benefits valuation, along with comparisons to the participants in the previous valuation at January 1, 2008 and a reconciliation of the number of participants in the last valuation to the number of participants in the current valuation.

## PARTICIPANT DATA

### Table B.1—Participant Data (Post-Retirement Non-Pension Benefits)

Membership data as at January 1, 2012 and at April 1, 2012 (for the transferred employees) was received from the Corporation via e-mail and included information such as sex, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of birth prior to date of hire.
- Salaries less than $20,000 per year, or greater than $250,000 per year.
- Ages under 18 or over 100.
- Abnormal levels of benefits and/or premiums.
- Duplicate records.

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

The statistical summaries below are presented as at April 1, 2012 and include all employees transferred into the Corporation at that date.

**Active Employees**

| *As of* | January 1, 2008 | | | April 1, 2012 | | |
|---|---|---|---|---|---|---|
| | **Male** | **Female** | **Total** | **Male** | **Female** | **Total** |
| Number of Employees | 1 | - | 1 | 35 | 18 | 53 |
| Average Length of Service | 31.2 | - | 31.2 | 14.0 | 10.9 | 12.9 |

| *As of April 1, 2012* | Current Age | | | | | |
|---|---|---|---|---|---|---|
| | Active Lives—Not fully eligible | | | Active Lives—Fully eligible | | |
| | Count | | | Count | | |
| | **Male** | **Female** | **Total** | **Male** | **Female** | **Total** |
| **Age Band** | | | | | | |
| Less than 30 | 5 | 1 | 6 | - | - | - |
| 30-35 | 5 | 2 | 7 | - | - | - |
| 36-40 | 2 | 1 | 3 | - | - | - |
| 41-45 | 5 | 2 | 7 | - | - | - |
| 46-50 | 10 | 4 | 14 | - | - | - |
| 51-55 | 3 | - | 3 | - | - | - |
| 56-60 | - | - | - | 5 | 5 | 10 |
| 61-65 | - | - | - | - | 3 | 3 |
| 66-70 | - | - | - | - | - | - |
| 71-75 | - | - | - | - | - | - |
| Greater than 75 | - | - | - | - | - | - |
| **Total** | **30** | **10** | **40** | **5** | **8** | **13** |

| *As of April 1, 2012* | Average Service | | | | | |
|---|---|---|---|---|---|---|
| | Active Lives—Not fully eligible | | | Active Lives—Fully eligible | | |
| | Service | | | Service | | |
| | **Male** | **Female** | **Total** | **Male** | **Female** | **Total** |
| **Age Band** | | | | | | |
| Less than 30 | 4.72 | 0.92 | 4.08 | - | - | - |
| 30-35 | 5.03 | 3.00 | 4.45 | - | - | - |
| 36-40 | 10.29 | 1.75 | 7.44 | - | - | - |
| 41-45 | 10.45 | 8.25 | 9.82 | - | - | - |
| 46-50 | 20.42 | 8.71 | 17.07 | - | - | - |
| 51-55 | 4.31 | - | 4.31 | - | - | - |
| 56-60 | - | - | - | 30.03 | 14.90 | 22.47 |
| 61-65 | - | - | - | - | 20.50 | 20.50 |
| 66-70 | - | - | - | - | - | - |
| 71-75 | - | - | - | - | - | - |
| Greater than 75 | - | - | - | - | - | - |
| **Total** | **11.29** | **6.00** | **9.97** | **30.03** | **17.00** | **22.01** |

**People in Receipt of Benefits**

| *As of* | January 1, 2008 | | | April 1, 2012 | | |
|---|---|---|---|---|---|---|
| | **Male** | **Female** | **Total** | **Male** | **Female** | **Total** |
| Number of Members | 22 | 8 | 30 | 19 | 6 | 25 |

| *As of April 1, 2012* | Expected Annual Benefit Payments | | |
|---|---|---|---|
| **Age Band** | **Male** | **Female** | **Total** |
| Less than 30 | $ - | $ - | $ - |
| 30-35 | - | - | - |
| 36-40 | - | - | - |
| 41-45 | - | - | - |
| 46-50 | - | - | - |
| 51-55 | - | - | - |
| 56-60 | 2,054 | - | 2,054 |
| 61-65 | 3,893 | - | 3,893 |
| 66-70 | 5,221 | 6,080 | 11,301 |
| 71-75 | 1,323 | - | 1,323 |
| Greater than 75 | 48,998 | 980 | 49,978 |
| **Total** | **$ 61,489** | **$ 7,060** | **$ 68,549** |

## PARTICIPATION DATA

**Table B.2—Participation Data (Post-Retirement Non-Pension Benefits)**

| | Actives | Retirees |
|---|---|---|
| *As at January 1, 2008* | **1** | **30** |
| New Entrants | - | - |
| Transfers from City of Brantford | 1 | - |
| Active | - | - |
| LTD | - | - |
| Terminated | - | - |
| Deceased | - | (5) |
| Retired | - | - |
| ***As at January 1, 2012*** | **2** | **25** |
| Transfers from City of Brantford | **51** | - |
| ***As at April 1, 2012*** | **53** | **25** |

## SUMMARY OF PLAN PARTICIPANTS

**Table B.3—Participation Data (Vested Sick Leave Benefits)**

Membership data as at January 1, 2012 and April 1, 2012 was received from the Corporation via e-mail and included information such as name, sex, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

| *Active Participants as of* | | **Jan 1, 2008 Total** | **Jan 1, 2012 Total** | **Apr 1, 2012 Total** |
|---|---|---|---|---|
| 1. | Total valued participants | 1 | 1 | 9 |
| 2. | Total annual pay | $142,600 | $155,800 | $574,500* |
| 3. | Average annual pay | $142,600 | $155,800 | $82,100* |
| 4. | Average age | 56.5 | 60.5 | 57.3 |
| 5. | Average service (years) | 31.2 | 35.2 | 30.5 |
| 6. | Average annual utilization of sick days (days) | N/A** | N/A** | N/A** |

* Annual pay figures are representative of 7 employees as the salaries of two employees are unavailable as they are paid out based on a frozen rate of pay at December 31, 1981.

** All vested sick leave banks are frozen.

### Data Checks Employed

In producing our valuation at January 1, 2012 and April 1, 2012, we have employed the following data error checks in order to ensure the accuracy of the data presented:

- Date of birth prior to date of hire.
- Salaries less than $20,000 per year, or greater than $250,000 per year.
- Ages under 18 or over 100.
- Accumulation of sick leave credits exceeding the allowable rates of accumulation.
- Payouts of sick leave banks exceeding the allowable levels of payout.
- Duplicate records.

| Vested Sick Leave Benefits | Actives |
|---|---|
| As at January 1, 2008 | 1 |
| New Entrants | - |
| Active | - |
| LTD | - |
| Terminated | - |
| Deceased | - |
| Retired | - |
| Correction | - |
| **As at January 1, 2012** | **1** |
| Transfers from City of Brantford | 9 |
| **As at April 1, 2012** | **10** |

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# SECTION C— SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

## ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension and vested sick leave benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions as to the discount rates, salary rate increases, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The ABO and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by CICA Section 3461 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement and vested sick leave benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. CICA Section 3461 stipulates that the attribution period commences at the employee's hire date and ends at the earliest age at which the employee could retire and qualify for the post-retirement non-pension and vested sick leave benefits valued herein.

For each employee not yet fully eligible for benefits, the ABO is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For extended health, dental, hospitalization, and travel benefits, we have used the following annual per capita claim costs as an estimate of the claims to be incurred:

| Group/Age Band | Hospital | EHC | Dental | Travel |
|---|---|---|---|---|
| **Admin** | | | | |
| 55-59 | $ 50 | $ 1,930 | $ 670 | $ 27 |
| 60-64 | $ 60 | $ 2,000 | $ 700 | $ 27 |
| **CUPE** | | | | |
| 55-59 | $ 50 | $ 2,290 | $ 720 | $ 27 |
| 60-64 | $ 60 | $ 2,920 | $ 690 | $ 27 |
| **IBEW** | | | | |
| 55-59 | $ 50 | $ 1,240 | $ 390 | $ 27 |
| 60-64 | $ 60 | $ 2,460 | $ 530 | $ 27 |
| **Ex PUC** | | | | |
| 55 - 59 | $ 50 | $ - | $ - | $ 27 |
| 60 – 64 | $ 60 | $ 1,240 | $ 380 | $ 27 |

The following rates were used to reflect the expected variation in retiree per capita claims costs by age:

| Age Band | Hospital | EHC | Dental | Travel |
|---|---|---|---|---|
| 65 – 69 | 8.0% | 3.0% | -0.5% | Nil |
| 70 – 74 | 7.8% | 3.0% | -0.5% | Nil |
| 75 – 79 | 4.5% | 3.0% | -0.5% | Nil |
| 80 + | 4.5% | 3.0% | -0.5% | Nil |

The annual per capita claim costs above were developed based on actual claims experience for the period from January 1, 2009 to December 31, 2011 for Brantford Power and the City of Brantford. Claims experience data was provided by the Corporation and Manulife.

The ABOs at January 1, 2012 and April 1, 2012 are based on membership data and management's best estimate assumptions at January 1, 2012.

## ACCOUNTING POLICIES

Pursuant to CICA 3461, the Corporation amortizes the amount of any gain or loss in excess of 10% of the ABO divided by the expected average remaining service lifetime of the active members of the group.

## MANAGEMENT'S BEST ESTIMATE ASSUMPTIONS

The following are management's best estimate economic and demographic assumptions as at January 1, 2012.

## ECONOMIC ASSUMPTIONS

### Consumer Price Index

The consumer price index is assumed to be 2.50% per annum.

The assumption used in the prior valuation was 2.00% per annum.

### Discount Rate

The rate used to discount future benefits is assumed to be 3.25% per annum. This rate reflects the market interest rates at the measurement date on high quality debt instruments with consideration given to the timing and amount of projected benefit payments.

The assumption used in the previous valuation was 5.00% per annum as at January 1, 2008 and 6.00% per annum as at December 31, 2008. More recently, the discount rate assumption was updated to 3.25% per annum as at December 31, 2011.

### Salary Increase Rate

The rate used to increase salaries is assumed to be 2.50% per annum. This rate reflects the Corporation's expectations for future salary increases to be in line with the expected Consumer Price Index.

The assumption used in the prior valuation was 3.00% per annum.

### Claims Cost Trend Rate

The rates used to project benefits costs into the future are as follows:

| | Current Valuation | | | Previous Valuation | | |
|---|---|---|---|---|---|---|
| **End of Year** | ***Health*** | ***Hospitalization*** | ***Dental*** | ***Health*** | ***Hospitalization*** | ***Dental*** |
| 2012 | 8.00% | 4.00% | 4.80% | 7.00% | 4.00% | 4.00% |
| 2013 | 7.47% | 4.00% | 4.80% | 6.00% | 4.00% | 4.00% |
| 2014 | 6.93% | 4.00% | 4.80% | 5.00% | 4.00% | 4.00% |
| 2015 | 6.40% | 4.00% | 4.80% | 5.00% | 4.00% | 4.00% |
| 2016 | 5.87% | 4.00% | 4.80% | 5.00% | 4.00% | 4.00% |
| 2017 | 5.33% | 4.00% | 4.80% | 5.00% | 4.00% | 4.00% |
| 2018 | 4.80% | 4.00% | 4.80% | 5.00% | 4.00% | 4.00% |
| 2019 | 4.80% | 4.00% | 4.80% | 5.00% | 4.00% | 4.00% |
| 2020 and Thereafter | 4.80% | 4.00% | 4.80% | 5.00% | 4.00% | 4.00% |

## DEMOGRAPHIC ASSUMPTIONS

### Annual Accumulation of Sick Leave

The vested sick leave banks for the Admin (Non-Union), CUPE, and IBEW Departments are all frozen with no additional accumulation of sick days. Therefore, there is no need for an assumption regarding the future annual usage of sick leave for the eligible employees.

This is consistent with the previous valuation.

### Mortality Table

Mortality is assumed to be in accordance with the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2020 based upon Projection Scale AA. This is the mortality table to be used in accordance with the Canadian Institute of Actuaries' Standard of Practice for Determining Pension Commuted Values, effective April 2009 to February 2011.

Mortality rates are applied on a sex-distinct basis.

The mortality table assumption used as at January 1, 2008 was the 1994 Uninsured Pensioner (UP-94) table, with a projection of mortality improvements to the year 2015 based upon Projection Scale AA. The mortality table assumption used as at December 31, 2009 was the 1994 Uninsured

Pensioner (UP-94) table, with a projection of mortality improvements to the year 2020 based upon Projection Scale AA.

**Rates of Withdrawal**

Termination of employment prior to age 55 is assumed to be equal to 2.00% per annum. This is the same assumption used in the prior valuation.

**Retirement Age**

All active employees are assumed to retire at age 59 in the current valuation. This is the same assumption used in the prior valuation.

**Family/Single Coverage**

It is assumed that the coverage type as at the valuation date will remain the same into retirement. For family coverage, we assume that the retiree has a spouse of opposite gender and no other dependents. These assumptions remain unchanged from the previous valuation.

**Expenses and Taxes**

We have assumed the following rates will apply in respect of the administration and premium and sales tax costs of sponsoring the post-retirement benefit program:

| **Administration Costs** | |
|---|---|
| Health and Dental | 5.6% of claims |
| Life Insurance | 5.0% of claims |
| Premium and Sales Tax | 10% of claims and admin costs |

We have assumed that there are no expenses associated with administering the vested sick leave benefit program.

These assumptions remain unchanged from the previous valuation.

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# SECTION D—
# SUMMARY OF POST-RETIREMENT AND VESTED SICK LEAVE BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation.

## GOVERNING DOCUMENTS

The program is governed by the following documents:

- Manulife Group Policy No. 0040078;
- The Corporation of the City of Brantford and The Association of Professional and Administrative Employees of the City of Brantford in full force and effect to March 31, 2012;
- The Corporation of the City of Brantford and The Canadian Union of Public Employees Local 181 City Hall Unit, in full force and effect to March 31, 2012; and
- The Corporation of the City of Brantford and The International Brotherhood of Electrical Workers Local 636
    - Unit 45, in full force and effect from June 1, 2010 to May 31, 2013;
    - Unit 41, in full force and effect from June 1, 2010 to May 31, 2013.

What follows is only a summary of the post retirement non-pension and vested sick leave benefit programs. For a complete description, please refer to the above noted documents.

## ELIGIBILITY

All employees who retire from the Corporation are eligible for post-retirement non-pension benefits as outlined in the Summary of Benefits below.

10 employees with frozen vested sick leave banks are eligible for post-employment vested sick leave benefits upon retirement, termination, or death.

## PARTICIPANT CONTRIBUTIONS

The Corporation shall pay a percentage of the cost of post-retirement life, dental, health, hospital, travel, and vision benefits as indicated in the Health and Dental Benefits table below.

The Corporation shall pay 100% of the cost of the post-employment vested sick leave benefits.

## PAST SERVICE

Past service is defined as continuous service prior to joining the plan if the participant was employed with another hydro prior to joining the Corporation.

## LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

## SUMMARY OF POST-RETIREMENT BENEFITS

### Life Insurance

All current employees are not eligible for post-retirement life insurance.

All current retirees are entitled to post-retirement life insurance as per the MEARIE plan, administered by Great West Life, with coverage as follows:

| Plan Option | Amount of Coverage | Eligibility |
|---|---|---|
| 1 | Flat $2,000. | If employee retires with less than 10 years of service in the Plan. |
| 2 | 50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings.<br>Reduction occurs on anniversary date of retirement. | If employee was ever insured under Employee Plan options 2, 3 or 4, **or** if employee retires with 10 or more years of service in Plan but was never in superseded plan. |
| 3 | 50% of final annual earnings. | If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only. |
| 4 | 70% of the final amount insured for under the life plan immediately prior to retirement. | If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only. |

**Extended Health and Dental Benefits**

| Active Groups | GROUP | 300 (Admin) | 320 (CUPE) | 330 (IBEW)* |
|---|---|---|---|---|
| Dental Benefits | Coverage ends | Age 65 | Age 65 | Age 65 |
| | % paid by Employer | 85% | 100% | 100% |
| Extended Health Coverage (EHC) | Coverage ends | Age 65 | Age 65 | Age 65 |
| | % paid by Employer | 100% | 100% | 100% |
| Hospital Coverage | Coverage ends | Age 65 | Age 65 | Age 65 |
| | % paid by Employer | 100% | 100% | 100% |
| Travel Benefits | Coverage ends | Age 65 | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Vision Benefits | Coverage ends | N/A | Age 65 | Age 65 |
| | % paid by Employer | N/A | 100% | 100% |

| Retiree Groups | GROUP | 130 (Ex PUC – Admin) | 160 (Ex PUC-Grandfathered) | 150 (Ex PUC – Power) |
|---|---|---|---|---|
| Dental Benefits | Coverage ends | Lifetime | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Extended Health Coverage (EHC) | Coverage ends | Lifetime (Survivor benefits to age 65) | Lifetime | Age 65 |
| | % paid by Employer | 100% | 100% | 100% |
| Hospital Coverage | Coverage ends | Age 65 | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Travel Benefits | Coverage ends | Lifetime | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Vision Benefits | Coverage ends | Lifetime | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |

* Spousal benefits are provided following the death of an eligible retiree until the date at which the retiree would have turned 65 years of age.

A detailed description of the health and dental benefits covered under the post-retirement non-pension benefits program can be found in the above-noted documents.

Dion Durrell

## SUMMARY OF VESTED SICK LEAVE BENEFITS

### Administrative Department, CUPE Department

The vested sick leave bank is frozen.

All eligible Administrative (Non Union) and CUPE employees (City Hall, Parks & Rec, and Works) are entitled to sick leave payouts upon retirement, death, and termination. The payout calculation is 1/2 of the vested hours multiplied by the hourly rate upon retirement/termination, to a maximum payout of 1/2 of the employee's ending annual salary.

### IBEW

The vested sick leave bank is frozen.

All eligible IBEW employees are entitled to sick leave payouts upon retirement, death, and termination. The payout calculation is 1/2 of the vested hours multiplied by the hourly rate at December 31, 1981, to a maximum payout of 1/2 of the employee's ending annual salary.

# SECTION E
# EMPLOYER CERTIFICATION

**Post-Retirement Non-Pension and Vested Sick Leave Benefit Plan**
**of Brantford Power Inc.**
**Actuarial Valuation as at January 1, 2012 and April 1, 2012**

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension and Vested Sick Leave Benefit Plan of Brantford Power Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the membership data summarized in Section B is accurate and complete;

ii) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on January 1, 2012 and April 1, 2012 (for transferred employees).

**BRANTFORD POWER INC.**

Oct 19 2012
Date

Signature

BRIAN D'Amboise
Name

C.F.O.
Title

MORNEAU SHEPELL

# POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF BRANTFORD POWER INC.

## ACTUARIAL VALUATION AS AT DECEMBER 31, 2012

Prepared April 2013

# Table of Contents



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# INTRODUCTION

## PURPOSE

Brantford Power Inc. (the "Organization") retained the services of Morneau Shepell Ltd. to perform a valuation of post-employment benefits as at December 31, 2012. The previous valuation was performed as at January 1, 2012 by Dion, Durrell + Associates Inc. This valuation was performed in accordance with Part V pre-changeover accounting standards, Section 3461 of the *Canadian Institute of Chartered Accountants Handbook ("CICA Handbook")* and the report presents the results of our valuation.

We determined the accrued benefit obligation and net benefit costs (i.e. the expense) for the following post-employment benefits (the "Plan"):

- health benefits,
- dental benefits, and
- life insurance benefits.

We understand the Organization accounts for its own sick leave benefits and therefore we did not value them in this report.

This report was prepared for the Organization for the following purposes:

- to determine the accrued benefit obligation for post-employment benefits as at December 31, 2012;
- to determine the net benefit cost to be recognized for financial statement purposes for the fiscal year ending December 31, 2012 ("Fiscal 2012");
- to estimate the net benefit cost to be recognized for financial statement purposes for the fiscal year ending December 31, 2013 ("Fiscal 2013");
- to provide the sensitivity disclosure items (relating to changes in the medical and dental trend rates) as required in the Organization's financial statements; and
- to provide the information and the actuarial opinion required by the Organization's auditor.

## RESULTS

### INCOME STATEMENT ITEMS

| | Estimated Fiscal 2013 | Fiscal 2012 |
|---|---|---|
| Current Service Cost | $60,762 | $73,635 |
| Interest Cost | 60,552 | 59,043 |
| Amortization of: | | |
| • Prior Service Cost | 0 | 0 |
| • Actuarial (Gain)/Loss | (15,903) | 0 |
| Net Benefit Cost (or the Expense) | 105,411 | 132,678 |

### RECONCILIATION BETWEEN FUNDED POSITION AND BALANCE SHEET

| | Estimated December 31, 2013 | December 31,2012 |
|---|---|---|
| Accrued Benefit Obligation ("ABO") | $1,735,724 | $1,724,162 |
| Assets | $0 | $0 |
| Funded Position | ($1,735,724) | ($1,724,162) |
| Unamortized Amounts | | |
| • Actuarial Losses (Gains) | ($379,151) | ($395,054) |
| • Past Service Costs | $0 | $0 |
| Accrued Benefit (Liability) / Asset | ($2,114,875) | ($2,119,216) |

A detailed expensing schedule with additional disclosure items can be found in Appendix G.

# ELIGIBILITY AND COST SHARING

## ELIGIBILITY FOR BENEFITS

The following table summarizes the eligibility for post-employment benefits and if eligible, the percentage of any premium paid by the retiree:

| Active Groups | GROUP | 300 (Admin) | 320 (CUPE) | 330 (IBEW) |
|---|---|---|---|---|
| Dental Benefits | Coverage ends | Age 65 | Age 65 | Age 65 |
| | % paid by Employer | 85% | 80% | 100% |
| Extended Health Coverage (EHC) | Coverage ends | Age 65 | Age 65 | Age 65 |
| | % paid by Employer | 100% | 100% | 100% |
| Hospital Coverage | Coverage ends | Age 65 | Age 65 | Age 65 |
| | % paid by Employer | 100% | 100% | 100% |
| Travel Benefits | Coverage ends | Age 65 | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Vision Benefits | Coverage ends | N/A | Age 65 | Age 65 |
| | % paid by Employer | N/A | 100% | 100% |

| Retiree Groups | GROUP | 130 (Ex PUC - Admin) | 160 (Ex PUC - Grandfathered) | 150 (Ex PUC - Power) |
|---|---|---|---|---|
| Dental Benefits | Coverage ends | Lifetime | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Extended Health Coverage (EHC) | Coverage ends | Lifetime (Survivor benefits to age 65) | Lifetime | Age 65 |
| | % paid by Employer | 100% | 100% | 100% |
| Hospital Coverage | Coverage ends | Age 65 | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Travel Benefits | Coverage ends | Lifetime | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |
| Vision Benefits | Coverage ends | Lifetime | N/A | Age 65 |
| | % paid by Employer | 100% | N/A | 100% |

Future retirees are not eligible for post-retirement life insurance. All members who retired before January 1, 2012 are entitled to post-retirement life insurance as per the MEARIE plan, administered by Great West Life, with coverage as detailed in Appendix E.

Eligibility for the continuation of benefits after retirement is based on attaining age 55 and does not depend on a minimum service condition.

# EVENTS AND CHANGES

## PLAN PROVISIONS

We understand through discussions with Brantford Power Inc. that there have been no significant changes in plan provisions since the previous valuation.

## ASSUMPTIONS

The actuarial assumptions and methods on which the calculations were based can be found in Appendix A.

Certain assumptions as at the valuation date differ from those adopted in the prior fiscal period.  The table below summarizes the impact of the changes in assumptions and demographics:

| | |
|---|---|
| Expected ABO at December 31, 2012<br>(before assumption and demographic changes) | $ 2,147,040 |
| Change in valuation methodology* | (119,529) |
| Change in membership demographics | (348,883) |
| Change in claim costs and trend rates | 135,645 |
| Improvement to mortality table | (29,759) |
| Change in discount rate (from 3.25% to 3.50%) | (60,352) |
| ABO at December 31, 2012 (after assumption and demographic changes) | $ 1,724,162 |

**Resulting from transition from prior actuaries to Morneau Shepell*

# VALUATION DETAILS

## STATEMENT OF FINANCIAL POSITION

The financial position of a post-employment benefit plan is determined by comparing the value of assets to the actuarial liability (also known as the accrued benefit obligation), assuming the plan continues indefinitely. The Organization's Plan is unfunded, as are most post-employment benefits plans in Canada. Therefore, there are no assets associated with the Organization's Plan.

The following table provides a breakdown of the accrued benefit obligation as at December 31, 2012. These figures are based on the plan provisions as summarized in Appendix D.

Appendix A provides the actuarial assumptions and the methodology used to determine the accrued benefit obligation. A discount rate of 3.50% per annum was used. A summary of the membership data can be found in Appendix C.

## TOTAL ACCRUED BENEFIT OBLIGATION AS AT DECEMBER 31, 2012

| | Extended Health* ($) | Dental ($) | Life ($) | Total ($) |
|---|---|---|---|---|
| Actives | 590,376 | 121,474 | 0 | 711,850 |
| Retirees | 295,128 | 70,944 | 646,240 | 1,012,312 |
| Total | 885,504 | 192,418 | 646,240 | 1,724,162 |

* *Includes hospital, travel, and vision benefits*

# ACTUARIAL OPINION

With respect to the post-employment benefits for employees of Brantford Power Inc., we performed a valuation as at December 31, 2012, based on data extrapolated to the valuation date and plan provisions as summarized in Appendix D.

With respect to the Organization's post-employment benefits, I hereby certify that, in my opinion, as at December 31, 2012:

- These benefits are defined benefits for purposes of Part V pre-changeover accounting standards, Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA Handbook").
- The valuation was performed in accordance with the standards of the Canadian Institute of Actuaries. The financial statement items resulting from the valuation and extrapolation thereof have been determined in accordance with my understanding of Part V pre-changeover accounting standards, Section 3461 of the CICA Handbook.
- The valuation was performed using best-estimate assumptions developed by the Organization as at December 31, 2012 and I do not express any opinion on such assumptions. These assumptions are summarized in Appendix A.
- I have confirmed with the Organization that the plan provisions are up to date as at the date of this report. I am not aware of any events that could have a significant effect on the valuation or on the Organization's financial statements.
- I am a member in good standing of the Canadian Institute of Actuaries. I understand that this report will be used for audit evidence and may be relied on under the terms of the CIA/CICA Joint Policy Statement as described in Section 1630 of the Canadian Institute of Actuaries Standards of Practice.
- I am, and Morneau Shepell Ltd. is, independent with respect to the Organization.

Furthermore, I hereby declare that in my opinion:

- The data upon which this valuation is based are sufficient and reliable for the purposes of the valuation; and
- This report has been prepared, and my opinion given, in accordance with generally accepted actuarial practice.

Emerging experience differing from assumptions will result in gains and losses which will be revealed in future valuations.

I am available, at your convenience, to provide you with any additional information that you may require.

Respectfully submitted,

MORNEAU SHEPELL LTD.
895 Don Mills Road
One Morneau Sobeco Centre
Toronto, Ontario
M3C 1W3

April 5, 2013

Heitham Hamam, FCIA

*This report and any enclosures were reviewed by Philip Fosu, FCIA*

# APPENDIX A – ACTUARIAL ASSUMPTIONS AND METHODS

## ACTUARIAL ASSUMPTIONS

| | December 31, 2012 Year End Obligation |
|---|---|
| **Economic Factors** | |
| Discount Rate for calculation of Net Benefit Cost (used to determine F2012 Expense) | 3.25% per annum |
| Discount Rate to determine Accrued Benefit Obligation for disclosure (at end of period) and Expense Estimate in following year | 3.50% per annum |
| Dental Cost Trend Rates | 5.00% per annum |
| Extended Health Care Trend Rates* | 9.0% in Fiscal 2012; decreasing by 0.25% per annum to an ultimate rate of 5.0% per annum thereafter |
| **Demographic Factors** | |
| Full eligibility age | Age 55 |
| Retirement age | Age 59 or immediate if older than 59 |
| Mortality | 1994 Uninsured Pensioner Mortality Table with full generational mortality improvement using Scale AA, Sex Distinct |
| Termination of employment | 2.0% per annum before age 55. No terminations are assumed after age 55. |
| Loadings (includes taxes and insurer expenses) | |
| Health and dental | 16.15% |
| life insurance | 17.69% |
| Disability | None |
| Age difference between retiree and spouse | Women are the same age as men |
| Members electing coverage at retirement | Current coverage will continue into retirement |

**Includes hospital, travel and vision benefits.*

The following table indicates the assumptions that have changed since the prior fiscal period:

| | Assumptions in Prior Valuation at January 1, 2012 |
|---|---|
| Extended Health Care Trend Rates | 8.0% per annum in 2012 grading down by 0.53% to 4.8% per annum in 2018 and thereafter |
| Hospital Trend Rates | 4.0% per annum |
| Travel Trend Rates | None |
| Dental Trend Rates | 4.8% per annum |
| Mortality | 1994 Uninsured Pensioner Mortality Table projected by Scale AA to the year 2020, Sex Distinct |
| Loadings (inclusive of taxes and insurer expenses) | |
| Health and dental | 15.6% |
| Life insurance | 15.0% |

In the tables above, all rates and percentages are annualized unless otherwise noted.

## ACTUARIAL COST METHOD

For all active employees, the accrued benefit obligation and the current service cost were calculated using the "projected benefit method pro-rated on service".

According to this method, the accrued benefit obligation is equal to the actuarial present value of all future benefits (net of retiree cost sharing), taking into account the assumptions described above, multiplied by the ratio of an employee's service at the valuation date to total service at the full eligibility date. The current service cost for a particular period is equal to the actuarial present value of benefits attributed to employees' services rendered in that period.

For each member who is at or beyond the full eligibility date, and for each pensioner, the accrued benefit obligation is determined as the actuarial present value of all future post-employment benefits which will be paid on their behalf.

# APPENDIX B – COST OF BENEFITS

## CALCULATION OF MEDICAL AND DENTAL COSTS

The steps that were undertaken to derive the claim costs for the valuation were as follows:

## CLAIM ANALYSIS:

- Historical active and retiree claim information over the period August 1, 2011 to December 31, 2012 was used to determine an average individual active and retiree claim cost per period.
- The average claim costs were loaded to reflect taxes and insurer expenses as presented in our actuarial assumptions.
- The average individual active and retiree claim cost per period was trended to Fiscal 2013 with the most recent claim periods receiving the highest weighting.
- The active and retiree claim cost was “aged” to reflect retiree claim patterns. The aging of claims reflects higher average health claims costs for retirees (and slightly lower retiree dental claim costs).
- Future claim cost levels were projected by applying the trend rate assumptions (as per Appendix A).
- Finally we assumed that the family cost for retirees is two times the cost of single coverage.

The following chart shows the estimated average Fiscal 2013 claim cost per covered retiree (not inclusive of assumed loadings):

## ESTIMATED AVERAGE ANNUAL RETIREE CLAIM COST FOR FUTURE RETIREE GROUPS – FISCAL 2013

| | 300 (Admin) | | 320 (CUPE) | | 330 (IBEW) | |
|---|---|---|---|---|---|---|
| | Extended Health* | Dental | Extended Health* | Dental | Extended Health* | Dental |
| 55 | $1,014 | $650 | $1,012 | $426 | $951 | $354 |
| 60 | $1,279 | $634 | $1,281 | $416 | $1,204 | $345 |
| 65 | $833 | $619 | $836 | $406 | $778 | $337 |

**Includes hospital, travel and vision benefits.*

## ESTIMATED AVERAGE ANNUAL RETIREE CLAIM COST FOR CURRENT RETIREE GROUPS – FISCAL 2013

| | 130 (Ex-PUC Admin) & 150 (Ex-PUC Power) | | 160 (Ex-PUC Grandfathered) |
|---|---|---|---|
| | **Extended Health*** | **Dental** | **Extended Health** |
| 55 | $652 | $371 | $522 |
| 60 | $819 | $362 | $655 |
| 65 | $384 | $353 | $307 |
| 70 | $445 | $344 | $356 |
| 75 | $521 | $335 | $417 |
| 80 | $595 | $327 | $476 |
| 85 | $657 | $319 | $526 |
| 90 | $700 | $311 | $560 |

**Includes hospital, travel and vision benefits.*

The total assumed Fiscal 2013 premiums (before any cost sharing) are tabled below (only for the groups which have a retiree cost-share component):

## TOTAL ANNUAL PREMIUM (INCLUDING TAXES) – FISCAL 2013

| | Dental |
|---|---|
| **300 (Admin)** | |
| Single | $493 |
| Family | $1,538 |
| **330 (CUPE)** | |
| Single | $485 |
| Family | $1,354 |

The Organization pays the full claim cost of the benefits less the portion paid by the retirees. The percentage of premium paid by the retirees is shown in the Eligibility and Cost Sharing section of this report.

# APPENDIX C – MEMBERSHIP DATA

## DESCRIPTION OF MEMBERSHIP DATA

We have based our valuation on active and retired participant data effective December 31, 2012, as supplied to us by the Organization.

We have performed tests to verify reasonableness and internal consistency and are satisfied that the data is sufficient and reliable for the purposes of this valuation.

## SUMMARY OF MEMBERSHIP DATA

- *Active Members*

### BY BENEFIT ELIGIBILITY

| | 300 (Admin) | 320 (CUPE) | 330 (IBEW) | Total |
|---|---|---|---|---|
| Males | 12 | 6 | 16 | 34 |
| Females | 10 | 9 | 2 | 21 |
| Number | 22 | 15 | 18 | 55 |
| Average age | 47.9 years | 47.2 years | 42.2 years | 45.9 years |
| Average service | 15.4 years | 8.9 years | 14.8 years | 13.4 years |

### TOTAL ACTIVE MEMBERS BY AGE AND SERVICE (THOSE ELIGIBLE FOR EXTENDED HEALTH* AND DENTAL BENEFITS)

| | | Service (years) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 0-4 | 5-9 | 10-14 | 15-19 | 20-24 | 25-29 | 30 | Total |
| Age | 20-24 | 1 | - | - | - | - | - | - | 1 |
| | 25-29 | 1 | 3 | - | - | - | - | - | 4 |
| | 30-34 | 4 | 3 | 1 | - | - | - | - | 8 |
| | 35-39 | - | 1 | 1 | - | - | - | - | 2 |
| | 40-44 | 3 | 3 | 1 | - | 1 | - | - | 8 |
| | 45-49 | 4 | - | 3 | - | 6 | 2 | - | 15 |
| | 50-54 | - | 3 | 1 | - | - | - | 1 | 5 |
| | 55-59 | 1 | 2 | - | - | - | - | 3 | 6 |
| | 60-64 | - | 1 | - | - | 2 | 2 | 1 | 6 |
| | **Total** | **14** | **16** | **7** | **-** | **9** | **4** | **5** | **55** |

**Including eligibility for hospital, travel and vision benefits*

- *Retirees*

### BY BENEFITS ELIGIBILITY FOR EXTENDED HEALTH AND DENTAL BENEFITS

| | 130 (Ex-PUC Admin) | 320 (CUPE) | 160 (Ex-PUC Grandfathered) | 150 (Ex-PUC Power) | Total |
|---|---|---|---|---|---|
| Single coverage | 4 | 2 | 11 | 2 | 19 |
| Family coverage | 4 | 1 | 1 | 1 | 7 |
| Total | 8 | 3 | 12 | 3 | 26 |
| Average age | 69.8 years | 63.0 years | 84.1 years | 63.4 years | 74.9 years |

### BY AGE – RETIREES WITH EXTENDED HEALTH AND DENTAL BENEFITS

| | 130 (Ex-PUC Admin) | 320 (CUPE) | 160 (Ex-PUC Grandfathered) | 150 (Ex-PUC Power) | Total |
|---|---|---|---|---|---|
| 55-59 | 0 | 1 | 0 | 0 | 1 |
| 60-64 | 0 | 2 | 0 | 3 | 5 |
| > 65 | 8 | 0 | 12 | 0 | 20 |
| Total | 8 | 3 | 12 | 3 | 26 |

### BY AGE – RETIREES WITH LIFE INSURANCE BENEFITS

| | 130 (Ex-PUC Admin) | 320 (CUPE) | 160 (Ex-PUC Grandfathered) | 150 (Ex-PUC Power) | Total |
|---|---|---|---|---|---|
| 55-59 | 0 | 0 | 0 | 0 | 0 |
| 60-64 | 0 | 0 | 0 | 2 | 2 |
| > 65 | 10 | 0 | 12 | 0 | 22 |
| Total | 10 | 0 | 12 | 2 | 24 |

# APPENDIX D – SUMMARY OF PLAN PROVISIONS

The following is a summary of the main provisions of post-retirement benefits for Brantford Power, Inc. This summary was based on information provided by the Organization.

## GOVERNING DOCUMENTS

The program is governed by the following documents:

- Manulife Group Policy No. 0040078
- The Corporation of the City of Brantford and The Association of Professional and Administrative Employees of the City of Brantford in full force and effect to March 31, 2012
- The Corporation of the City of Brantford and The Canadian Union of Public Employees Local 181 City Hall Unit, in full force and effect to March 31, 2012; and
- The Corporation of the City of Brantford and The International Brotherhood of Electrical Workers Local 636
    - Unit 45, in full force and effect from June 1, 2010 to May 31, 2013
    - Unit 41, in full force and effect from June 1, 2010 to May 31, 2013

## SUMMARY OF LIFE INSURANCE BENEFITS

Future retirees are not eligible for post-retirement life insurance. All members who retired before January 1, 2012 are entitled to post-retirement life insurance as per the MEARIE plan, administered by Great West Life, with coverage as follows:

| Plan Option | Amount of Coverage | Eligibility |
|---|---|---|
| **1.** | Flat $2,000 | If employee retires with less than 10 years of service in the Plan. |
| **2.** | 50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings.<br>Reduction occurs on anniversary date of retirement. | If employee was ever insured under Employee Plan options 2, 3 or 4, **or** if employee retires with 10 or more years of service in Plan but was never in superseded plan. |
| **3.** | 50% of final annual earnings. | If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only. |
| **4.** | 70% of the final amount insured for under the life plan immediately prior to retirement. | If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only. |

## APPENDIX E – CASH FLOW PROJECTION

The following table presents the cash flow projection for the retirees for the 3 fiscal years following the valuation date. The assumptions used are the same as those shown in Appendix A. Members are assumed to terminate, die, and retire after the valuation date in accordance with the assumptions. We assume that there are no new active members to the plan; since the cash flow projection is in respect of the retiree group, this assumption does not materially impact the cash flow projection.

| | Cashflows |
|---|---|
| Projected Fiscal 2013 | $109,752 |
| Projected Fiscal 2014 | 117,719 |
| Projected Fiscal 2015 | 117,371 |

# APPENDIX F – ACCOUNTING POLICIES

## MEASUREMENT DATE

The Organization uses a December 31st measurement date for valuing post-employment benefits.

## AMORTIZATION OF NET ACTUARIAL LOSS (GAIN)

Actuarial gains and losses in a year are combined with the unamortized balance of gains or losses from prior years. The Organization has adopted an accounting policy that amortizes the portion of the total that exceeds 10% of the accrued benefit obligation into future years' expenses over the average remaining service period of active employees (the "Corridor Method").

## AMORTIZATION OF PRIOR SERVICE COSTS

Prior service costs (if any) arising from a plan amendment are amortized over future years of service to full eligibility of active employees.

# APPENDIX G – ACCOUNTING SCHEDULE

| Fiscal Year | *Estimate* January 1, 2013 to December 31, 2013 | January 1, 2012 to December 31, 2012 |
|---|---|---|
| **Starting values** | | |
| Accrued benefits | 1,724,162 | 953,416 |
| Adjustment due to transfer on April 1 | - | 1,086,046 |
| Adjusted Accrued benefits | 1,724,162 | 2,039,462 |
| Assumed discount rate on liabilities at Beginning of Period ("BOP") | 3.50% | 3.25% |
| Assumed discount rate on liabilities at End of Period ("EOP") | 3.50% | 3.50% |
| Accrual for service (normal cost) | 60,762 | 73,635 |
| Actual benefit payments | 109,752 | 25,100 |
| Expected benefit payments | 109,752 | 88,000 |
| Average Remaining Service Period to retirement | 14.0 | 12.0 |
| Average Remaining Service Period to full eligibility | 11.0 | 12.0 |
| **Exhibit I - Interest on accrued benefits** | | |
| Opening balance | 1,724,162 | 953,416 |
| Adjustment due to transfer on April 1 | - | 1,086,046 |
| Adjusted Accrued benefits | 1,724,162 | 2,039,462 |
| Accrual for service | 60,762 | 73,635 |
| Benefit payments (mid-year) | (54,876) | (12,551) |
| Total | 1,730,048 | 2,100,547 |
| Interest | 60,552 | 59,043 |
| **Exhibit II - Experience gains/ losses - accrued benefits** | | |
| Opening balance | 1,724,162 | 2,039,462 |
| Accrual for service | 60,762 | 73,635 |
| Interest on accrued benefits | 60,552 | 59,043 |
| Prior service costs | - | - |
| Benefit payments | (109,752) | (25,100) |
| Expected value at EOP | 1,735,724 | 2,147,040 |
| Actual value at EOP | 1,735,724 | 1,724,162 |
| Experience gain (loss) | - | 422,878 |
| **Exhibit III - Unamortized experience** | | |
| Experience gain/(loss) at BOP | 395,054 | (27,824) |
| 10% Corridor | 172,416 | n/a |
| Total amount to be amortized | 222,638 | - |
| Amortization amount | (15,903) | - |
| Changes during year | - | 422,878 |
| Experience gain/(loss) at EOP | 379,151 | 395,054 |
| **Exhibit IV - Post-retirement benefits cost recognized** | | |
| Accrual for services (total) | 60,762 | 73,635 |
| Interest on accrued benefits | 60,552 | 59,043 |
| Actuarial (gains) losses during year | - | (422,878) |
| Plan amendments during year | - | - |
| Net Benefit Cost Incurred | 121,314 | (290,200) |
| Adjustment for experience (gains)/losses | (15,903) | 422,878 |
| Adjustment for prior service costs | - | - |
| Net expense | 105,411 | 132,678 |
| **Exhibit V - Calculation of accrual** | | |
| Accrued benefit liability at BOP | 2,119,216 | 925,592 |
| Adjustment due to transfer on April 1 | - | 1,086,046 |
| Adjusted accrued benefit liability | 2,119,216 | 2,011,638 |
| Expense (Income) for the year | 105,411 | 132,678 |
| Funding contributions (total) | (109,752) | (25,100) |
| Accrued benefit liability at EOP | 2,114,875 | 2,119,216 |
| **Exhibit VI - Reconciliation** | | |
| Accrued benefit obligation at EOP | 1,735,724 | 1,724,162 |
| Less unamotized: | | |
| Experience (gains)/losses | (379,151) | (395,054) |
| Prior service costs | - | - |
| Accrued benefit liability at EOP | 2,114,875 | 2,119,216 |
| **Exhibit VI - Sensitivity in Health and Dental Care Trends** | | |
| Trend 1% Higher | | |
| Change in Service and Interest Cost (F2012) | | 20,341 |
| Change in Accrued benefit obligation (December 31, 2012) | | 127,178 |
| Trend 1% Lower | | |
| Change in Service and Interest Cost (F2012) | | (16,815) |
| Change in Accrued benefit obligation (December 31, 2012) | | (107,822) |

# CHARGES FROM AFFILIATES FOR SERVICES PROVIDED

## Introduction

BPI has purchased services from its affiliate, the City, since 1998. In 2000 following deregulation of the electricity distribution sector, BPI entered into an SSA with the City for a full range of services including: Operations and Maintenance, Engineering Construction and Design, Metering, Settlement, Inventory Management, Finance, Regulatory, Administration, Utilities Accounting (now Finance), Treasury, Legal, Human Resources, IT Services, use and maintenance of facilities, Records Management, Mail Delivery, Telephone, Insurance and Risk Management Services and up to 2011, Senior Management services.

As discussed above in this Exhibit, employees that performed functions that were exclusive to BPI were transferred to BPI on April 1, 2012. At that time, the City's Customer Services Department was split with employees providing BPI customer care and billing transferred to BPI. The remaining services purchased from the City under a renegotiated SSA dated January 1, 2013 are discussed below.

A summary of charges from affiliates for services provided for each year are shown in Table 4.31 below. A copy of the Shared Services Agreement is provided as Appendix B to this Exhibit.

The following section describes in brief the services that BPI purchases from the City as of January 1, 2013. Each service is described in detail in the schedules to the Shared Services Agreement attached as Appendix B to this Exhibit. The various descriptions include a reference to the specific schedules in the SSA

**Accounts Payables Services** includes the processing and reviewing of accounts payables, issuing payments through mail or electronic funds transfer. The service provider's Financial Information System is used to process accounts payables. The price for the service is based on fully allocated actual costs as determined by the number of lines per BPI invoices processed as a percentage of total invoice lines processed by the service provider. The percentage of costs allocated to BPI is 14.4%. (SSA - Schedule A-1);

**Payroll Services** include the processing of BPI payroll, preparation of payroll remittances for various agencies and governmental authorities and completing statutory and regulatory reporting. The service provider's Financial Information System is used to provide payroll services. The price for the service is based on fully allocated actual costs as determined by BPI's yearly average FTE head count as a percentage of the City's total yearly average FTE head count. The percentage of costs allocated to BPI is 4.08%. (SSA - Schedule A-2);

**Purchasing Services** includes purchasing and consulting services on a requested basis for the procurement of goods and services from third party vendors in accordance with BPI's Purchasing Policy attached as Appendix C to this Exhibit. Services are priced on actual costs using the time required to provide the service as the basis for fully allocated costing. (SSA Schedule A-3);

**Human Resources Services** include human resources administration services, health and safety services and employment and labour relations services. Administration services involve employee administration and benefits management and prices are based on the fully allocated actual costs as determined by BPI's yearly average FTE head count as a percentage of the City's total yearly average FTE head count. Similarly, health and safety services are based on fully allocated actual costs as determined by BPI's yearly average FTE head count as a percentage of the City's total yearly average FTE head count and include health and safety compliance, Zeroquest certification, WSIB claims management and attendance support programs. The percentage of costs allocated to BPI for these 2 services is 4.08%. .Employment and labour relations services include collective agreement negotiations and administration, staff recruitment and salary administration based on BPI's collective and employment agreements. The prices for these services are based on fully allocated actual costs using the time required to provide the service as the basis for fully allocated costing. (SSA -Schedule A-4);

**Information Technology Services** include installation, maintenance, licensing and support of all hardware and software used by BPI. As well, the service provider provides, maintains and supports all networks including network security, e-mail and internet services. The service provider will work on special projects as agreed upon between BPI and the service provider. Services are priced on fully allocated actual costs as follows:

- For core network services, the number of BPI network users as a percentage of total network users; the percentage of costs allocated to BPI is 9%;

- For Financial Information System use, the number of BPI users as a percentage of total users of the service provider's Financial Information System; the percentage of costs allocated to BPI is 6%;

- For management of Information Technology Services, the estimated time spent managing services; the percentage of costs allocated to BPI is 25%.

- For support of systems owned and used exclusively by BPI, the total expenses to support those systems; that is, 100% of the cost of the function is allocated to BPI;

- For web development and maintenance charges, hourly charge-out rate based on time required to produce the services; and

- For special projects and systems development, the estimated cost of the project determined on a per project basis. (SSA - Schedule A-5).

**Legal And Real Estate Services** include basic legal representation and advice and in-house legal representation to service provider departments providing services to BPI. Real Estate services involve the sale of any surplus BPI properties or purchase of properties. Both services include searches of public registries and registrations. Services are priced on fully allocated actual costs using the time required to provide the service as the basis for fully allocated costing. (SSA - Schedule A-6);

**Mail Run Services** include delivery of mail from the service provider's location to two of BPI's facilities. Prices are based on market prices to provide such services (SSA - Schedule A-7);

**Postage Services** involve the processing of outgoing mail excluding customer invoices and including the cost of postage. Prices are based actual costs using the actual number of pieces of mail plus the fully allocated administrative costs to process such services. (SSA - Schedule A-8);

**Telephone Services** includes provision of a telephone system to BPI locations including system support and repairs, administration and switchboard services. Cost are based on fully allocated actual costs as determined by the number of telephone lines used by BPI as a percentage of total number of telephone lines used by the City; The percentage of costs allocated to BPI is 15.11%. (SSA - Schedule A-9);

**Insurance and Risk Management Services** include the placement and management of general comprehensive liability insurance, property insurance and vehicle insurance, claims administration, assistance in developing risk management procedures and advice on contracts. Along with the actual premium costs, administrative costs are based on the value of BPI premiums as a percentage of premiums administered by the City. The percentage of costs allocated to BPI is 6.15%. (SSA - Schedule A-10);

**Records Management Services** include records storage, retrieval and destruction as well as maintenance of file plans and retention schedules. Prices are based on market prices to provide such services. (SSA - Schedule A-11);

**Facility Asset Management Services** includes management of the properties, referred to Repair and Maintenance services, used by BPI. Those properties include Administration offices at 84 Market Street, Customer Services offices at 220 Colborne Street and a service centre at 400 Grand River Avenue. BPI's stores and vehicle garage are also located at 400 Grand River Avenue. The repair and maintenance services include all aspects of property management such as janitorial, mechanical, electrical, security, landscaping and general maintenance and repairs. For the costs to administer this service, prices are based on fully allocated actual costs as determined by the estimated percentage of time spent performing such services. Repairs and maintenance services are based on actual costs applied to the square footage of space used by BPI in those properties as a percentage of the total square footage of the facilities. (SSA - Schedule A-12);

**Rental Of Facilities – Office Space** pertains to the rental fee paid by BPI for use of Administration offices at 84 Market Street and Customer Services facilities at 220 Colborne Street. The rental fee is based on market rates applied to the square footage of space occupied by BPI. (SSA - Schedule A-13);

**Rental Of Facilities – Office, Warehouse, Vehicle Storage** pertains to the rental fee paid by BPI for use of facilities at 400 Grand River Avenue, which is the location of its Service Centre. The rental fee is based on market rates applied to the square footage of space occupied by BPI. (SSA - Schedule A-14);

**Tree Trimming Services (or Forestry Services)** include coordinating tree trimming requirements with the third party vendor, scheduling emergency work as required and assessing trees. A third party vendor selected as a result of a valid tendering procedure undertakes actual tree trimming work. Prices are based on market as determined through this valid tendering process and applied to the percentage of BPI's actual work orders. The percentage of costs allocated to BPI is 48%. (SSA - Schedule A-15).

## Variance Analysis

### Overview

In its 2008 Cost-of-Service Rate Application, BPI distinguished between those services that were exclusive to BPI as "Purchase of Service" transactions and those services that were shared with its affiliate. These services included Operations and Maintenance, Engineering, Line Locates, Metering and Settlement, and Regulatory and Administration. The costs attributable to those services were presented in aggregate at that time and, as a result, cannot be separated out by function for variance analysis back to 2008 Board Approved amounts. However, as all of those function were transferred to BPI on April 1, 2012, the costs related to those functions have been discussed in the overall cost variance analysis presented above in Exhibit 4, Tab 2, Schedule 3. Similarly, the costs pertaining to Finance, Inventory Management and Customer Services Departments which were transferred to BPI on April 1, 2012 have also been included in the preceding variance analysis.

Prior to January 1, 2013, charges for services were made to Brantford's energy group of companies and then allocated among the corporate family comprising BEC, BHI/BGI and BPI. Under the new Shared Services Agreement, charges are billed directly to BPI without any allocations among the corporate family. Although no longer applicable to pricing methodologies in place starting in 2013, the historical corporate costs allocation practices among the Energy group of companies are set out in Appendix 2-N to this application.

The following materiality and variance analysis pertains only to those services that continue to be purchased from BPI's affiliate, the City under a renegotiated SSA. These functions were transferred to BPI in 2012.

## 2008 Actual to 2013 Test Year

## Table 4.31 - Affiliate Services Variance – 2008 Board Approved – 2013 Test Year

| Name of Company | | Service Offered | Cost for the Service 2008 | Cost for the Service 2013 | Variance | Variance |
|---|---|---|---|---|---|---|
| From | To | | $ | $ | $ | % |
| City of Brantford | Brantford Power Inc. | Operations and Maintenance | $ - | $ - | $ - | #DIV/0! |
| City of Brantford | Brantford Power Inc. | Vehicle Maintenance | $ 185,000.00 | $ - | $ (185,000.00) | -100% |
| City of Brantford | Brantford Power Inc. | Engineering | $ - | $ - | $ - | #DIV/0! |
| City of Brantford | Brantford Power Inc. | Metering & Settlement | $ - | $ - | $ - | #DIV/0! |
| City of Brantford | Brantford Power Inc. | Line Locates | $ - | $ - | $ - | #DIV/0! |
| City of Brantford | Brantford Power Inc. | Regulatory & Administration | $ - | $ - | $ - | #DIV/0! |
| City of Brantford | Brantford Power Inc. | Meeting Management Services | $ 13,284.00 | $ - | $ (13,284.00) | -100% |
| City of Brantford | Brantford Power Inc. | Records Management | $ 20,250.00 | $ 17,000.00 | $ (3,250.00) | -16% |
| City of Brantford | Brantford Power Inc. | Mail Services | $ 5,738.00 | $ 14,927.00 | $ 9,189.00 | 160% |
| City of Brantford | Brantford Power Inc. | Insurance and Risk Management | $ 216,000.00 | $ 143,133.00 | $ (72,867.00) | -34% |
| City of Brantford | Brantford Power Inc. | Customer Services | $ 1,152,752.00 | $ - | $ (1,152,752.00) | -100% |
| City of Brantford | Brantford Power Inc. | Telephone Services | $ 40,500.00 | $ 21,124.00 | $ (19,376.00) | -48% |
| City of Brantford | Brantford Power Inc. | Finance | $ 359,663.00 | $ - | $ (359,663.00) | -100% |
| City of Brantford | Brantford Power Inc. | Treasury, Purchasing | $ 172,850.00 | $ 134,053.00 | $ (38,797.00) | -22% |
| City of Brantford | Brantford Power Inc. | IT Services | $ 966,000.00 | $ 911,700.00 | $ (54,300.00) | -6% |
| City of Brantford | Brantford Power Inc. | Facilities | $ 807,313.00 | $ 538,098.00 | $ (269,215.00) | -33% |
| City of Brantford | Brantford Power Inc. | Legal Services | $ 60,314.00 | $ 55,000.00 | $ (5,314.00) | -9% |
| City of Brantford | Brantford Power Inc. | Human Resources | $ 67,178.00 | $ 64,639.00 | $ (2,539.00) | -4% |
| City of Brantford | Brantford Power Inc. | Forestry | $ 331,969.00 | $472,409 | $ 140,440.00 | 42% |
| City of Brantford | Brantford Power Inc. | Senior Management | $ 35,025.00 | $ - | $ (35,025.00) | -100% |
| | | | | | | |
| **Total - Shared Services that BPI continues to purchase under renegotiated Service Level Agreement** | | | **$ 2,723,137.00** | **$ 2,372,083.00** | **$ (351,054.00)** | **-13%** |

## Table 4.32 - Affiliate Services Variance – 2008 Actual – 2013 Test Year

| Name of Company | | Service Offered | Cost for the Service 2008 | Cost for the Service 2013 | Variance | Variance |
|---|---|---|---|---|---|---|
| From | To | | $ | $ | $ | % |
| City of Brantford | Brantford Power Inc. | Operations and Maintenance | $ 1,296,472.41 | $ - | $ (1,296,472.41) | -100% |
| City of Brantford | Brantford Power Inc. | Vehicle Maintenance | $ 213,715.42 | $ - | $ (213,715.42) | -100% |
| City of Brantford | Brantford Power Inc. | Engineering | $ 945,736.76 | $ - | $ (945,736.76) | -100% |
| City of Brantford | Brantford Power Inc. | Metering & Settlement | $ 715,665.71 | $ - | $ (715,665.71) | -100% |
| City of Brantford | Brantford Power Inc. | Line Locates | $ 95,430.10 | $ - | $ (95,430.10) | -100% |
| City of Brantford | Brantford Power Inc. | Regulatory & Administration | $ 459,615.72 | $ - | $ (459,615.72) | -100% |
| City of Brantford | Brantford Power Inc. | Meeting Management Services | $ 13,284.00 | $ - | $ (13,284.00) | -100% |
| City of Brantford | Brantford Power Inc. | Records Management | $ 18,728.52 | $ 17,000.00 | $ (1,728.52) | -9% |
| City of Brantford | Brantford Power Inc. | Mail Services | $ 5,030.22 | $ 14,927.00 | $ 9,896.78 | 197% |
| City of Brantford | Brantford Power Inc. | Insurance and Risk Management | $ 190,256.88 | $ 143,133.00 | $ (47,123.88) | -25% |
| City of Brantford | Brantford Power Inc. | Customer Services | $ 1,048,109.82 | $ - | $ (1,048,109.82) | -100% |
| City of Brantford | Brantford Power Inc. | Telephone Services | $ 37,795.87 | $ 21,124.00 | $ (16,671.87) | -44% |
| City of Brantford | Brantford Power Inc. | Utilities Accounting | $ 385,228.41 | $ - | $ (385,228.41) | -100% |
| City of Brantford | Brantford Power Inc. | Treasury, Purchasing | $ 172,850.40 | $ 134,053.00 | $ (38,797.40) | -22% |
| City of Brantford | Brantford Power Inc. | Inventory Management | $ 254,360.22 | $ - | $ (254,360.22) | -100% |
| City of Brantford | Brantford Power Inc. | IT Services | $ 802,580.27 | $ 911,700.00 | $ 109,119.73 | 14% |
| City of Brantford | Brantford Power Inc. | Facilities | $ 747,335.53 | $ 538,098.00 | $ (209,237.53) | -28% |
| City of Brantford | Brantford Power Inc. | Legal Services | $ 136,360.57 | $ 55,000.00 | $ (81,360.57) | -60% |
| City of Brantford | Brantford Power Inc. | Human Resources | $ 69,824.98 | $ 64,639.00 | $ (5,185.98) | -7% |
| City of Brantford | Brantford Power Inc. | Forestry | $ 424,149.98 | $472,409 | $ 48,259.02 | 11% |
| City of Brantford | Brantford Power Inc. | Senior Management | $ 33,356.76 | $ - | $ (33,356.76) | -100% |
| | | | | | | |
| **Total - Shared Services that BPI continues to purchase under renegotiated Service Level Agreement** | | | **$ 2,638,269.98** | **$ 2,372,083.00** | **$ (266,186.98)** | **-10%** |

**IT Services** service charges increased by $109,119.73. In 2012, IT changed their method of calculating IT Network Services to include cost of staffing, which was previously not included in the calculation. Pricing methodologies put in place in 2013 under the renegotiated Shared Services Agreement resulted in slight decreases to the 2012 price.

**Facilities** service charges decreased by ($209,237.53). The decrease is a result of a change in methodology to move to market-based pricing under the renegotiated Shared Services Agreement and a reduction in the space occupied by the Customer Services function at the 220 Colborne Street location.

## 2011 to 2013 Test Year

**Table 4.33 - Affiliate Services Variance – 2011 Actual – 2013 Test Year**

| Name of Company | | Service Offered | Cost for the Service 2011 | Cost for the Service 2013 | Variance | Variance |
|---|---|---|---|---|---|---|
| From | To | | $ | $ | $ | % |
| City of Brantford | Brantford Power Inc. | Operations and Maintenance | $ 1,315,542.90 | $ - | $ (1,315,542.90) | -100% |
| City of Brantford | Brantford Power Inc. | Vehicle Maintenance | $ 187,121.12 | $ - | $ (187,121.12) | -100% |
| City of Brantford | Brantford Power Inc. | Engineering | $ 847,245.82 | $ - | $ (847,245.82) | -100% |
| City of Brantford | Brantford Power Inc. | Metering & Settlement | $ 824,579.41 | $ - | $ (824,579.41) | -100% |
| City of Brantford | Brantford Power Inc. | Line Locates | $ 97,571.22 | $ - | $ (97,571.22) | -100% |
| City of Brantford | Brantford Power Inc. | Regulatory & Administration | $ 507,703.34 | $ - | $ (507,703.34) | -100% |
| City of Brantford | Brantford Power Inc. | Meeting Management Services | $ 13,284.00 | $ - | $ (13,284.00) | -100% |
| City of Brantford | Brantford Power Inc. | Records Management | $ 17,025.96 | $ 17,000.00 | $ (25.96) | 0% |
| City of Brantford | Brantford Power Inc. | Mail Services | $ 2,818.62 | $ 14,927.00 | $ 12,108.38 | 430% |
| City of Brantford | Brantford Power Inc. | Insurance and Risk Management | $ 130,910.04 | $ 143,133.00 | $ 12,222.96 | 9% |
| City of Brantford | Brantford Power Inc. | Customer Services | $ 1,066,712.83 | $ - | $ (1,066,712.83) | -100% |
| City of Brantford | Brantford Power Inc. | Telephone Services | $ 51,754.99 | $ 21,124.00 | $ (30,630.99) | -59% |
| City of Brantford | Brantford Power Inc. | Utilities Account (now Finance) | $ 329,721.16 | $ - | $ (329,721.16) | -100% |
| City of Brantford | Brantford Power Inc. | Treasury, Purchasing | $ 160,253.09 | $ 134,053.00 | $ (26,200.09) | -16% |
| City of Brantford | Brantford Power Inc. | Inventory Management | $ 220,971.65 | $ - | $ (220,971.65) | -100% |
| City of Brantford | Brantford Power Inc. | IT Services | $ 768,301.83 | $ 911,700.00 | $ 143,398.17 | 19% |
| City of Brantford | Brantford Power Inc. | Facilities | $ 592,494.90 | $ 538,098.00 | $ (54,396.90) | -9% |
| City of Brantford | Brantford Power Inc. | Legal Services | $ 65,891.62 | $ 55,000.00 | $ (10,891.62) | -17% |
| City of Brantford | Brantford Power Inc. | Human Resources | $ 65,437.83 | $ 64,639.00 | $ (798.83) | -1% |
| City of Brantford | Brantford Power Inc. | Forestry | $ 330,240.65 | $472,409 | $ 142,168.35 | 43% |
| City of Brantford | Brantford Power Inc. | Senior Management | $ - | $ - | $ - | |
| | | | | | | |
| **Total - Shared Services that BPI continues to purchase under renegotiated Service Level Agreement** | | | **$ 2,185,129.53** | **$ 2,372,083.00** | **$ 186,953.47** | **9%** |

**IT Services** charges increased by $143,398.17. In 2012, IT changed their method of calculating IT Network Services to include cost of staffing which was previously not included in the calculation. This change in approach to costing has been set out in the renegotiated Shared Services Agreement with the City.

**Forestry (Tree Trimming)**

Except for administrative costs related to the provision of this service, this service is delivered to BPI by a contracted third-party provider selected through a valid tendering procedure. The $142,168.35 increase between 2011 and 2013 is a result of a scheduled increase to fees in 2012 under the previous third-party contract, which expired that year and the results of a valid tendering process undertaken for 2013.

# APPENDIX B

# SHARED SERVICES AGREEMENT

**SHARED SERVICES AGREEMENT**

**BETWEEN**

**THE CORPORATION OF THE CITY OF BRANTFORD**

– and –

**BRANTFORD POWER INC.**

**JANUARY 1, 2013**

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# SHARED SERVICES AGREEMENT

**THIS AGREEMENT** is dated and effective as of January 1, 2013.

**B E T W E E N :**

**THE CORPORATION OF THE CITY OF BRANTFORD**

(the "**City**")

- and -

**BRANTFORD POWER INC.**, a corporation incorporated under the laws of Ontario

("**BPI**")

**CONTEXT**

**A.** The City provides certain of services that will meet the operational requirements of BPI.

**B.** BPI requires that the City provide the Services to facilitate the operation of the Business.

**THEREFORE**, the Parties agree as follows:

## ARTICLE 1
## INTERPRETATION

### 1.1 Definitions

In this Agreement, the following terms have the following meanings:

1.1.1 "**Affected Price**" is defined in Section 2.4.2.

1.1.2 "**Affected Service**" is defined in Section 2.4.2.

1.1.3 "**Affiliate**" means an affiliate as that term is defined in the *Business Corporations Act* (Ontario).

1.1.4 "**Agreement**" means this agreement, including all Schedules, as it may be confirmed, amended, modified, supplemented or restated by written agreement between the Parties.

1.1.5 "**Applicable Law**" means, at any time, with respect to any Person, property, transaction or event, all applicable laws, statutes, regulations, treaties, judgments and decrees and (whether or not having the force of law) all applicable official directives, rules, codes, consents, approvals, by-laws, permits, authorizations, guidelines, orders and policies of any Persons having authority over that Person, property, transaction or event.

1.1.6 **"Arbitration Act"** is defined in Section 7.4.

1.1.7 **"Arbitrator"** is defined in Section 7.4.

1.1.8 **"ARC"** means the Ontario Energy Board's *Affiliate Relationships Code for Electricity Distributors and Transmitters*, as amended, restated and replaced from time to time.

1.1.9 **"Business"** means the business of distributing electricity to residential, commercial and industrial customers in the City of Brantford.

1.1.10 **"Business Day"** means any day excluding a Saturday, Sunday or statutory holiday in the Province of Ontario, and also excluding any day on which the principal chartered banks located in the City of Brantford are not open for business during normal banking hours.

1.1.11 **"BPI"** is defined in the recital of the Parties above.

1.1.12 **"BPI Data"** is defined in Section 3.4.

1.1.13 **"City"** is defined in the recital of the Parties above.

1.1.14 **"Communication"** means any notice, demand, request, consent, approval or other communication which is required or permitted by this Agreement to be given or made by a Party.

1.1.15 **"Commodity Taxes"** means all taxes levied on or measured by, or referred to as transfer, land transfer, registration charges, gross receipt, sales, retail sales, use, consumption, goods and services, harmonized sales, value-added, turnover, excise or stamp, all customs duties, countervail, anti-dumping and special import measures, and all import and export taxes.

1.1.16 **"Comparable Service"** is defined in Section 4.2.3.

1.1.17 **"Confidential Information"** means any information relating to BPI or its Business, including:

1.1.17.1 Personal Information;

1.1.17.2 Customer Information;

1.1.17.3 information relating to the assets, business plans, Customers, Employees, equipment, financial statements and financial performance, intellectual property, inventory, market strategies, operations, pricing, products, suppliers, and trade secrets of BPI; and

1.1.17.4 all analyses, compilations, records, data, reports, correspondence, memoranda, specifications, materials, applications, technical data, studies, derivative works, reproductions, copies, extracts, summaries or other documents containing or based upon, in whole or in part, any of the information listed above in this Section 1.1.17,

whether communicated in written form, orally, visually, demonstratively, technically or by any other electronic form or other media, or committed to memory, and whether or not designated, marked, labelled or identified as confidential or proprietary, but excluding information, other than Personal Information, which:

1.1.17.5 was, is or becomes available to or known by the public, other than as a result of improper disclosure by the City or any of its Representatives, before the end of the Term; or

1.1.17.6 was or is obtained from a source other than BPI, any of its Representatives, or any Person bound by a duty of confidentiality to BPI or the Business.

1.1.18 "**Consents**" is defined in Section 3.5.

1.1.19 "**Cost Change**" is defined in Section 4.2.3.

1.1.20 "**Customer**" means any Person who is a customer of BPI or has been a customer of BPI.

1.1.21 "**Customer Information**" means any information relating to a Customer, including information BPI has obtained relation to a specific smart sub-metering provider, wholesaler, consumer, retailer, or generator in the process of providing current or prospective utility service.

1.1.22 "**Defaulting Party**" is defined in Section 2.3.

1.1.23 "**Disputes**" is defined in Section 7.1.

1.1.24 "**Employee**" means any employee or independent contractor employed or retained in connection with the Business on a full-time or part-time basis, including any who are on medical or long-term disability leave, or other statutory or authorized leave or absence.

1.1.25 "**FAC Services**" means those Services identified under the heading "FAC Services" on Schedule B, the fees for which are determined on a fully-allocated cost basis by the City, which the Parties acknowledge are also "shared corporate services" (as such term is defined in the ARC).

1.1.26 "**Facilitated Negotiation Period**" is defined in Section 7.3.

1.1.27 "**Facilitator**" is defined in Section 7.3.

1.1.28 "**Failing Party**" is defined in Section 2.5.

1.1.29 "**Force Majeure**" means acts of God; laws, orders, rules, regulations, acts and restraints of armies, militaries, enemies, terrorists, and Governmental Authorities; war, revolutions, mobilization, political and civil unrest or insurrection, embargos, disturbances and riots; epidemics, outbreak of disease and quarantine; inclement weather including floods, storms, tornados, hurricanes, tsunamis, earthquakes, volcanic eruptions and landslides; explosions and fire; labour issues including disputes, walkouts, strikes, slowdowns, lockouts and picketing; damage, destruction or expropriation of property; delays or defaults in or caused by, and shortages of, power, water, transportation and common carriers, facilities, labour, subcontractors, goods, materials and supplies; and any other event or occurrence beyond the reasonable control of the Failing Party.

1.1.30 "**Governmental Authority**" means:

1.1.30.1 any federal, provincial, state, local, municipal, regional, territorial, aboriginal, or other government, governmental or public department, branch, ministry, or court, domestic or foreign, including any district, agency, commission, board, arbitration panel or authority and any subdivision of any of them exercising or entitled to exercise any administrative, executive, judicial, ministerial, prerogative, legislative, regulatory, or taxing authority or power of any nature; and

1.1.30.2 any quasi-governmental or private body exercising any regulatory, expropriation or taxing authority under or for the account of any of them, and any subdivision of any of them, including the Ontario Energy Board.

1.1.31 "**Indemnified Party**" is defined in Section 6.4.1.

1.1.32 "**Indemnifying Party**" is defined in Section 6.4.1.

1.1.33 "**Initial Term**" is defined in Section 2.1.

1.1.34 "**Licences**" is defined in Section 3.5.

1.1.35 "**Local Market Survey**" is defined in Section 4.2.3.

1.1.36 "**Loss**" means:

1.1.36.1 any loss, liability, damage, cost, expense, charge, fine, penalty or assessment including the costs and expenses of any action, suit, proceeding, demand, assessment, judgment, settlement or compromise and all interest, fines, penalties and reasonable professional fees and disbursements;

but excluding

1.1.36.2 indirect, incidental, special, consequential, exemplary, punitive or reliance damages or liability of any kind, including for any death or personal injury, as well as any loss or anticipated loss of business profit, business information, business reputation or business goodwill, or for any business interruption, even if the Party against whom the Loss is claimed, or its agents, employees or other personnel, have been advised of the possibility of any such damages, liabilities, or losses.

1.1.37 "**Market Differential**" is defined in Section 4.2.3.

1.1.38 "**Monthly Invoice**" is defined in Section 4.2.1.

1.1.39 "**Negotiation Period**" is defined in Section 7.2.2.

1.1.40 "**Non FAC Services**" means those Services identified under the heading "Non FAC Services" on Schedule B, the fees for which are determined on a market basis by the City.

1.1.41 "**Non-Requesting Party**" is defined in Section 7.3.

1.1.42 "**Parties**" means the City and BPI, collectively, and "**Party**" means any one of them.

1.1.43 "**Person**" means:

1.1.43.1 a natural person, whether acting in his or her own capacity, or in his or her capacity as executor, administrator, estate trustee, trustee or personal or legal representative, and the heirs, executors, administrators, estate trustees, trustees or other personal or legal representatives of a natural person;

1.1.43.2 a corporation or a company of any kind, a partnership of any kind, a sole proprietorship, a trust, a joint venture, an association, an unincorporated association, an unincorporated syndicate, an unincorporated organization or any other association, organization or entity of any kind; and

1.1.43.3 a Governmental Authority.

1.1.44 "**Personal Information**" means information relating to identifiable individuals.

1.1.45 "**Requesting Party**" is defined in Section 7.3.

1.1.46 "**Renewal Period**" is defined in Section 2.2.1.

1.1.47 "**Representatives**" means advisors, agents, consultants, directors, officers, management, employees, subcontractors, and other representatives, including accountants, auditors, financial advisors, lenders and lawyers of a Party.

1.1.48 "**Secondary Information**" is defined in Section 5.2.

1.1.49 "**Semi-Annual Adjustment**" is defined in Section 4.2.2.

1.1.50 "**Semi-Annual Period**" is defined in Section 4.2.2.

1.1.51 "**Semi-Annual Statement**" is defined in Section 4.2.2.

1.1.52 "**Services**" means the services set forth on Schedule A.

1.1.53 "**Term**" means the Initial Term and each Renewal Period, if any.

1.1.54 "**Termination Date**" is defined in Section 8.7.1.

1.1.55 "**Third Party Agreements**" is defined in Section 3.5.

## 1.2 Certain Rules of Interpretation

1.2.1 In this Agreement, words signifying the singular number include the plural and vice versa, and words signifying gender include all genders. Every use of the words "including" or "includes" in this Agreement is to be construed as meaning "including, without limitation" or "includes, without limitation", respectively.

1.2.2 The division of this Agreement into Articles and Sections, the insertion of headings and the inclusion of a table of contents are for convenience of reference only and do not affect the construction or interpretation of this Agreement.

1.2.3 References in this Agreement to an Article, Section, or Schedule are to be construed as references to an Article, Section, or Schedule of or to this Agreement unless otherwise specified.

1.2.4 Unless otherwise specified in this Agreement, time periods within which or following which any calculation or payment is to be made, or action is to be taken, will be calculated by excluding the day on which the period begins and including the day on which the period ends. If the last day of a time period is not a Business Day, the time period will end on the next Business Day.

1.2.5 Unless otherwise specified, any reference in this Agreement to any statute includes all regulations and subordinate legislation made under or in connection with that statute at any time, and is to be construed as a reference to that statute as amended, modified, restated, supplemented, extended, re-enacted, replaced or superseded at any time.

1.2.6 If there is any conflict between the provisions of this Agreement and provisions in any of the Schedules, the provisions of this Agreement will govern.

## 1.3 Governing Law

This Agreement is governed by, and is to be construed and interpreted in accordance with, the laws of the Province of Ontario and the laws of Canada applicable in that Province.

## 1.4 Entire Agreement

This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter of this Agreement and supersede all prior agreements, understandings, negotiations and discussions, whether oral or written, of the Parties, and there are no representations, warranties or other agreements between the Parties in connection with the subject matter of this Agreement except as specifically set out in this Agreement. No Party has been induced to enter into this Agreement in reliance on, and there will be no liability assessed, either in tort or contract, with respect to, any warranty, representation, opinion, advice or assertion of fact, except to the extent it has been reduced to writing and included as a term in this Agreement.

## 1.5 Business Day

Whenever any calculation or payment to be made or action to be taken under this Agreement is required to be made or taken on a day other than a Business Day, the calculation or payment is to be made, or action is to be taken on the next Business Day.

## 1.6 Payment and Currency

Any money to be advanced, paid or tendered by one Party to another under this Agreement must be advanced, paid or tendered by bank draft, certified cheque or wire transfer of immediately available funds payable to the Person to whom the amount is due. Unless otherwise specified, the word "dollar" and the "$" sign refer to Canadian currency, and all amounts to be advanced, paid, tendered or calculated under this Agreement are to be advanced, paid, tendered or calculated in Canadian currency.

## 1.7 Schedules

The following Schedules are incorporated by reference into and deemed to be a part of this Agreement:

| **Schedule** | **Subject Matter** |
|---|---|
| A | Defined Terms for Service Schedules |
| A-1 | Accounts Payable |
| A-2 | Payroll |
| A-3 | Purchasing |

| Schedule | Subject Matter |
| --- | --- |
| A-4 | Human Resources |
| A-5 | Information Technology Services |
| A-6 | Legal and Real Estate Services |
| A-7 | Mailrun |
| A-8 | Postage Service |
| A-9 | Telephone Services |
| A-10 | Insurance & Risk Management |
| A-11 | Records Management |
| A-12 | Facility Asset Management (property management) |
| A-13 | Rental of Facilities – Office Space |
| A-14 | Rental of Facilities – Office/Warehouse/Vehicle Storage |
| A-15 | Tree Trimming |
| B | FAC Services and Non FAC Services |

## ARTICLE 2
## TERM AND TERMINATION

### 2.1 Term

The initial term of this Agreement (the "**Initial Term**") will be for a consecutive 4 year period commencing on January 1, 2013 and continuing through to and including the date immediately prior to the consecutive 4 year anniversary date of that date, subject to the termination provisions set out in this Agreement.

### 2.2 Renewals

2.2.1 The Initial Term may be extended for any period (any such extension, a "**Renewal Period**") provided that the Parties agree to the terms of a Renewal Period at least 6 months prior to the end of the Initial Term or then current term.

2.2.2 At least 12 months prior to the end of the Initial Term the Parties will provide a written notice to the other setting forth the intention of such Party to enter into discussions regarding a Renewal Period.

2.2.3 Notwithstanding anything in this Section 2.2 to the contrary, there shall be no obligation on either Party to enter into an agreement for a Renewal Period.

## 2.3 Termination

This Agreement may be terminated by a Party upon 30 Business Days notice to the other Party (the "**Defaulting Party**") upon the occurrence of any of the following events:

2.3.1 if the Defaulting Party is in default of any material term of this Agreement and the default has not been cured within 30 Business Days of written notice of that default having been given by one Party to the Defaulting Party;

2.3.2 if the Defaulting Party becomes insolvent, makes an assignment for the benefit of creditors or is the subject of any proceeding under any bankruptcy and/or insolvency law;

2.3.3 if the Defaulting Party winds up, dissolves, liquidates or takes steps to do so or otherwise ceases to function as a going concern; or

2.3.4 if a receiver or other custodian (interim or permanent) of any of the assets of the Defaulting Party is appointed by private instrument or by court order or if any execution or other similar process of any court becomes enforceable against the Defaulting Party or its assets or if distress is made against any of the Defaulting Party's assets.

## 2.4 ARC Compliance

2.4.1 The Parties acknowledge that BPI is an electricity distributor licensed and regulated by the Ontario Energy Board under the *Ontario Energy Board Act, 1998.*

2.4.2 If BPI advises the City in writing that all or any part of a Service (an "**Affected Service**") or all or any part of the pricing or pricing mechanism underlying charges for a Service (an "**Affected Price**") is causing BPI to contravene the ARC the Parties agree to proceed as follows:

2.4.2.1 the Parties will make, and participate in, good faith efforts to agree to conform an Affected Service or Affected Price to the requirements of the ARC and amend the applicable Schedule accordingly;

2.4.2.2 if the Parties cannot agree to conform an Affected Service or Affected Price under Section 2.4.2.1 within a reasonable period of time, BPI will make an application to the Ontario Energy Board for an exemption for the Affected Service or Affected Price from the requirements of the ARC; and

2.4.2.3 if BPI makes an application to the Ontario Energy Board for an exemption for the Affected Service or Affected Price from the requirements of the ARC and such an application is unsuccessful, the Parties agree that the

City will cease performing all or part of the Affected Service and/or charging the Affected Price, as applicable, and all or part of the Affected Service and/or Affected Price, as applicable, will be deemed to be inoperative for the remainder of the Term. For certainty, where only part of an Affected Service and/or Affected Price is inoperative under this 2.4.2.3 the City may, at its option, cease to perform the whole of such Affected Service if the City determines, in its sole discretion, that such performance is impractical.

## 2.5 Force Majeure

If a Party (the "**Failing Party**") is unable or fails to perform any or all of its duties and obligations under this Agreement by reason of Force Majeure, the Failing Party will not be liable to the other Party during the period of Force Majeure and to the extent of its inability or failure, but:

2.5.1 the Failing Party claiming Force Majeure must notify the other Party promptly and in any event, in writing within 72 hours after the Force Majeure event, setting out in reasonable detail the nature of the event, giving a good faith estimate of the expected duration of the event and outlining the steps the Failing Party intends to take to mitigate the effect of the event; and

2.5.2 the Failing Party will make all commercially reasonable efforts in the circumstances to surmount the event of Force Majeure, and to resume full performance as soon as it is reasonably possible to do so, provided that the Failing Party will not be required to settle any walkout, strike or labour dispute on commercially unreasonable terms.

## 2.6 Termination Without Prejudice

Any termination of this Agreement pursuant to Section 2.3 shall be without prejudice to any other remedies which any Party may have against the other arising out of a breach or default and shall not affect any rights or obligations of any Party arising under this Agreement prior to such termination.

## 2.7 Continuing Obligation

Termination of this Agreement will not release, discharge or otherwise affect the obligation of BPI to pay for any Services provided to it before the termination took effect, including any interest on unpaid amounts as contemplated by Section 4.4.

# ARTICLE 3
# SERVICES

## 3.1 Provision of Services

3.1.1 The City agrees to provide the Services to BPI throughout the Term as set forth in Schedule A.

3.1.2 The City shall perform the Services in accordance with the standards and service levels as set forth in the Schedules.

## 3.2 Provision of Information by the Parties

BPI will provide any information, data or other items reasonably required by the City to provide the Services, including any information requested in writing by the City. The City will also provide BPI at its reasonable written request with such information within the City's control in order for BPI to determine its compliance with the ARC. A Party receiving an oral information request will, if requested, acknowledge that request in writing to the other Party and, if reasonably required under the circumstances provide an estimate of the time by which the requested information will be delivered.

## 3.3 Personnel

The City will provide all necessary and appropriate personnel to perform the Services. The personnel performing the Services will not be required to perform services exclusively for BPI, but may also provide similar services for the City and other entities. The Services will be performed during the City's normal business hours. While providing the Services, the City's personnel will remain employees of the City. The City will be responsible for all wages, benefits, withholdings for tax purposes, and all other employer liabilities and responsibilities relating to all of its personnel.

## 3.4 Processing Errors

BPI is responsible from the date of this Agreement for the accuracy and completeness of all information submitted by BPI to the City (whether communicated in written form, orally, or by any other electronic form or other media) for processing or transmission in connection with the Services, including all original reports, intellectual property, computer programs, information, data or other items (collectively, the "**BPI Data**") and for any errors in and with respect to the BPI Data obtained from the City because of any inaccurate or incomplete BPI Data.

## 3.5 Third Party Agreements

The Parties recognize that certain Services and/or certain related software and hardware licences (the "**Licences**") are provided by third parties under specific third party agreements (the "**Third Party Agreements**"). The City will use commercially reasonable efforts to obtain any necessary consents, approvals or amendments under its Third Party Agreements or any other existing agreements necessary to allow the City to provide the Services to BPI (the "**Consents**"). BPI will pay the cost of obtaining the Consents, if any, and any fees or charges associated with the Consents, including any additional licence or sublicense fees.

### 3.6 Security

The City will maintain adequate back-up material that will enable the regeneration of BPI Data, computer files, printer output and other data generated in the course of providing the Services, in case any of it is destroyed. At least one copy of all back-up material will be stored in secure premises off-site until a new back-up copy replaces it. For the purposes of this Section, back-up material will mean exact copies of the magnetic tapes, disks or other BPI Data furnished to, or in the possession of, the City at any time. The City will adopt reasonable measures and safeguards to prevent the loss, damage or destruction of BPI Data and back-up material.

### 3.7 General Limitations

Nothing in this Agreement will:

3.7.1 require the City to perform any services not provided for in this Agreement;

3.7.2 require the City to make any change or addition that will require any capital expenditures by the City without the prior agreement of the City;

3.7.3 prohibit the City from making minor changes or additions to the Services, so long as the City continues to provide the Services substantially in the manner set forth in the Schedules; or

3.7.4 prohibit the City from adjusting the fees for the Services in accordance with Section 4.2.

### 3.8 Status of Parties

The Parties acknowledge that they are separate entities, and that the execution and performance of this Agreement does not create a partnership or joint venture between them.

## ARTICLE 4
## PAYMENT

### 4.1 Charges

The charges for the Services will be calculated as set out in Schedule A, in each case plus all applicable Commodity Taxes.

### 4.2 Monthly Invoicing and Annual Reconciliations

4.2.1 Each month the City will prepare and deliver to BPI an invoice for amounts that are estimated as payable to it in respect of the Services provided in the immediately preceding month (each such invoice, a "**Monthly Invoice**").

4.2.2 Following July 31 and December 31 of each calendar year during the Term (each such period, a "**Semi-Annual Period**") the City will reconcile the Monthly Invoices delivered to BPI in each Semi-Annual Period against the actual fees, costs and expenses payable by BPI in accordance with agreed pricing terms set forth in the Schedules for FAC Services provided during the applicable Semi-Annual Period (each such adjustment, a "**Semi-Annual Adjustment**"). No later than 60 days following the last day of the preceding Semi-Annual Period the City will deliver a semi-annual statement to BPI reflecting any balances due or credits owing in connection with an Semi-Annual Adjustment (each such statement, a "**Semi-Annual Statement**") for FAC Services. All balances due from BPI on a Semi-Annual Statement will automatically be subject to payment in accordance with Section 4.2.4. Any credits owing to BPI on a Semi-Annual Statement will automatically be applied to the following Monthly Invoice. Subject to Section 4.2.4, the City may continue to reconcile the fees charged for any Semi-Annual Period for FAC Services in accordance with this Section 4.2.2 notwithstanding the completion of any Semi-Annual Adjustment or delivery of any Semi-Annual Statement.

4.2.3 To the extent that there is a change in the City's costs in delivering any Non FAC Service (each such change, a "**Cost Change**") the City may adjust the pricing of the applicable Non FAC Service set forth in the applicable Schedule in accordance with this Section 4.2.3. The City will perform an updated review of local market rates for services comparable to the Non FAC Service subject to the Cost Change (a "**Comparable Service**") available in the City of Brantford (the "**Local Market Survey**"). In the event that there is a difference in price between the Non FAC Service set forth in the applicable Schedule and the price for a Comparable Service set forth in the Local Market Survey (each such price differential, a "**Market Differential**"), the City may adjust the price for the Non FAC Service set forth in the applicable Schedule by an amount equal to the Market Differential. The City may adjust for a Market Differential at any time during the Term effective as of the date of any Cost Change. All adjustments for Cost Changes will be reflected on the Monthly Invoice following the City's determination of a Cost Change. All balances due from BPI on a Monthly Invoice will automatically be subject to payment in accordance with Section 4.2.4. Any credits owing to BPI on a Monthly Invoice will automatically be applied to the following Monthly Invoice. Subject to Section 4.2.4, the City may continue to adjust for Market Differentials at any time during the Term in accordance with this Section 4.2.2.

4.2.4 No further reconciliations of the fees charged for FAC Services under Section 4.2.2 or adjustments for Market Differentials for Non FAC Services under Section 4.2.3 may be made by the City after 60 calendar days following December 31 of each calendar year in which such FAC Services and/or Non FAC Services were invoiced. Notwithstanding the foregoing, the Parties acknowledge that:

4.2.4.1 the portion of the fees charged for FAC Services and/or Non FAC Services that are classified as "out-of-pocket" expenses by the City and incurred by the City on BPI's behalf may not be known within 60 calendar days following December 31 of each calendar year in which such FAC Services and/or Non FAC Services were invoiced; and

4.2.4.2 the City may continue to reconcile and adjust the charges for the portion of the fees for FAC Services and/or Non FAC Services that are classified as "out-of-pocket" expenses by the City at any time during the Term, whenever such "out-of-pocket" expenses were incurred or invoiced by the City.

### 4.3 Payment

Payment of amounts owed by BPI to the City will be made by the 30th day after receipt of the Monthly Invoice or Semi-Annual Statement. Payments will be made to an account specified by the City in writing. If there is a dispute as to the amount payable to the City for Services rendered, BPI will, within 15 days of receipt of the Monthly Invoice or Semi-Annual Statement, notify the City in writing that it disputes the Monthly Invoice or Semi-Annual Statement. BPI will be deemed to have finally accepted the Monthly Invoice or Semi-Annual Statement unless it delivers its dispute notice to the City within the applicable time period. Despite the submission of a dispute notice by BPI, BPI will pay to the City all amounts that are invoiced.

### 4.4 Default

If BPI fails to comply with its payment obligations in accordance with this Agreement, interest will be billed to BPI from the due date until paid in full at a rate of 24% per annum in accordance with the Fees and Charges Bylaw of the City.

## ARTICLE 5
## COVENANTS

### 5.1 Confidentiality

5.1.1 The City acknowledges and agrees that:

5.1.1.1 BPI is the exclusive owner of all right, title and interest in and to the Confidential Information; and

5.1.1.2 the City has no right, title, licence, or interest in or to the Confidential Information, except for the right, subject to this Agreement, to review the Confidential Information for the purpose of carrying out its obligations under this Agreement.

Accordingly, the City agrees to hold in strict confidence and not disclose or use, and the City will not allow any of its Representatives to disclose or use, any Confidential Information, for any purpose, except as provided in this Section 5.1.

5.1.2 BPI or any of its Representatives will disclose Confidential Information to the City or any of its Representatives upon the following conditions:

5.1.2.1 the City will hold, and will cause its Representatives to hold, all Confidential Information in trust for BPI and will not use, or permit any of its Representatives to use, any of the Confidential Information, at any time or in any manner, except as is required by the City to carry out its obligations under this Agreement;

5.1.2.2 the City will limit the disclosure of the Confidential Information to those of its Representatives who have a need to know the Confidential Information to assist the City in carrying out its obligations under this Agreement, who are informed by the City of the confidential nature of the Confidential Information and who agree in writing to act in accordance with and be bound by the terms and conditions of this Agreement;

5.1.2.3 the City will not permit its Affiliates or their Representatives to access any Customer Information; and

5.1.2.4 the City will be responsible for any breach of this Section 5.1, or any disclosure, divulgence, communication or use of any Confidential Information in a manner not authorized by this Agreement by any of its Representatives.

5.1.3 The City will take appropriate measures to protect the Confidential Information and will keep a record of the location of the Confidential Information and all of its Representatives to whom Confidential Information is provided. The City will store the Confidential Information properly and securely and ensure that appropriate technical and organizational means and physical or electronic storage media are in place to protect the Confidential Information against unauthorized or unlawful access or processing, and against accidental loss, destruction or damage, including taking reasonable steps to ensure the reliability of any Representative of the City permitted by the City to have access to the Confidential Information. The City will permit BPI upon 10 Business Days prior written notice to audit and review the City's electronic access and security procedures and protocols pursuant to the standards set forth in ARC section 2.2.2.

5.1.4 The City will, upon the written request of BPI, return promptly to BPI, or destroy, and provide written certification of the destruction of, all documents, physical or tangible manifestations and electronic and computerized forms of the Confidential Information received from BPI, including all copies, reproductions and applications of the Confidential Information, but the City will be entitled to retain copies of these records only as may be necessary to establish the City's satisfactory performance of its obligations under this Agreement and to comply with Applicable Law, Governmental Authority or audit requirements.

5.1.5 If the City or any Representative of the City is required by any Applicable Law or by any Governmental Authority to disclose any Confidential Information, the City or that Representative will provide BPI with prompt written notice of that requirement, so that BPI may contest the disclosure of the Confidential Information and seek an appropriate protective order or other appropriate remedy.

5.1.6 If, in the absence of a protective order or other appropriate remedy, the City or any Representative of the City is, in the reasonable opinion of its lawyers, required by any Applicable Law or by any Governmental Authority to disclose any Confidential Information or stands liable for contempt or to suffer other censure or penalty, then the City or that Representative may, without liability under this Agreement, disclose that portion of the Confidential Information, but only that portion, that the City or the Representative is legally required to disclose.

5.1.7 The City will notify BPI immediately upon discovery of any breach of this Section 5.1 or any unauthorized or unlawful disclosure, divulgence, communication or use of any Confidential Information.

5.1.8 The covenants and obligations contained in this Section 5.1 will be perpetual.

### 5.2 Computer Back-up

The Parties acknowledge that the computers and data storage and retrieval systems or network of the City and, if applicable, its Representatives, may automatically back up Confidential Information stored in electronic form. The Parties agree that to the extent that those back-up procedures automatically create electronic copies of Confidential Information (the "**Secondary Information**"), each of the City and, if applicable, its Representatives, may, despite any requirement under this Agreement to return or destroy Confidential Information, retain Secondary Information in its archival storage for the period that it would normally archive electronic data, provided that those data are periodically and systematically overwritten or otherwise destroyed. Secondary Information will be subject to the provisions of this Agreement until destroyed and may not be accessed by the City or any of its Representatives during its period of archival storage.

### 5.3 Security of Electronic Information

Use of Confidential Information by, or disclosure of Confidential Information to, any person that is not a Party to this Agreement or a Representative of the City permitted by the City to have access to the Confidential Information, that results from a breach of the electronic security of the computers and data storage and retrieval systems or network of the City or, if applicable, any Representative of the City, will be treated as a disclosure by the City contrary to the terms of this Agreement, provided that the breach results from a failure by the City or, if applicable, any of its Representatives, to implement appropriate security measures consistent with best practices or otherwise take necessary precautions in order to secure the Confidential Information.

### 5.4 Books of Account and Information

Each of BPI and the City will maintain at its head office appropriate books of account and records with respect to all transactions entered into in the performance of this Agreement. Each of BPI and the City will provide to the other whatever additional reports and information relating to the Services provided under this Agreement which the other may reasonably request.

## ARTICLE 6
## INDEMNIFICATION

### 6.1 Indemnification by City

The City agrees to defend, indemnify and save harmless BPI, its agents or employees, from and against any Loss sustained or incurred by BPI, its agent or employees, which arises or results directly from:

6.1.1 the breach by the City of any representation, warranty or covenant contained in this Agreement;

6.1.2 the failure to deliver the Services if that failure lasts for more than three Business Days or if there are more than five instances of failure in any one year period; or

6.1.3 any negligent or wilful act or omission of the City or its Representatives.

### 6.2 Indemnification by BPI

BPI agrees to defend, indemnify and hold harmless the City, its agents or employees, from and against any Loss sustained or incurred by the City, its agents or employees, which arises or results directly from the breach by BPI of any representation, warranty or covenants contained in this Agreement.

### 6.3 Limitation on Indemnification by City

The indemnification obligations of the City pursuant to Section 6.1 are strictly limited to the sum of the aggregate amount of fees paid by BPI to the City pursuant to this Agreement during the then immediately preceding 12 month period, calculated from the date on which such liability arose. This Section 6.3 will prevail in the event of any conflict between the terms of this Agreement and this Section 6.3.

**6.4 Third Party Claims**

6.4.1 Upon receipt of a claim by either Party (the "**Indemnified Party**") from a third party for which the other Party (the "**Indemnifying Party**") has agreed to indemnify the Indemnified Party, the Indemnified Party will notify the Indemnifying Party in writing of that claim.

6.4.2 Upon receipt of that notice, the Indemnifying Party will have the right to defend and/or settle any such claim at its own expense, provided that the Indemnifying Party advises the Indemnified Party of its intention to do so with 30 days of receipt of that notice.

6.4.3 If the Indemnifying Party fails to advise the Indemnified Party within the time specified in Section 6.4.2, the Indemnified Party will have the right but not the obligation to defend or settle that claim, employing counsel chosen exclusively by the Indemnified Party, in which case the Indemnifying Party will indemnify the Indemnified Party for all amounts which it is required to pay in settlement or satisfaction of those claims and will reimburse the Indemnified Party for all expenses (including reasonable legal fees and costs) incurred in the defence or compromise that claim.

6.4.4 Any settlement of any claim by the Indemnifying Party must include a full and complete release of the Indemnified Party.

**6.5 Disclaimer and Release**

6.5.1 **Except as expressly provided in this Agreement and to the maximum extent permitted by any Applicable Law, the City gives no condition, warranty, undertaking or representation, implied or otherwise, in respect of the Services.**

6.5.2 **The remedies of the Parties set out in Sections 6.1 and 6.2 are exclusive and in substitution for, and each Party waives, releases and disclaims, all other warranties, obligations and liabilities of the other Party and all other remedies, rights and claims against the Party, express or implied, arising by law, statute or otherwise, with respect to the Services and any other items subject to, or related or associated with, this Agreement, including, any warranty of merchantability or fitness for a particular purpose; any warranty arising from course of performance, course of dealing or usage of trade; any obligation, liability, right, remedy or claim in tort, despite any fault, negligence, omission or strict liability of the City (whether active, passive or imputed); and any obligation, liability, remedy, right or claim for infringement.**

**6.6 Continuing Obligation**

The indemnities in this Article 6 are continuing and irrevocable and the obligations of a Party under this Agreement will not be released, discharged, impaired or affected by:

6.6.1 any extensions of time or variations of obligations which the Party may grant or permit in respect of the observance or performance of any of the obligations of the Party;

6.6.2 any waiver by or neglect or failure of the Party to enforce any of the terms, covenants and conditions in respect of this Agreement; or

6.6.3 any amendment to this Agreement.

## ARTICLE 7
## DISPUTE RESOLUTION

### 7.1 Disputes

All disputes, disagreements, controversies, questions or claims arising out of or relating to this Agreement, including, without limitation, with respect to its formation, execution, validity, application, interpretation, performance, breach, termination or enforcement (collectively, "**Disputes**"), will be determined in accordance with this Article 7, which sets out the exclusive procedure for the resolution of Disputes

### 7.2 Negotiation

7.2.1 The Parties will make, and participate in, good faith efforts to resolve any Dispute by negotiation. Each of the Parties will appoint a designated officer whose task it will be to meet for the purpose of endeavouring to resolve the Dispute. In the case of BPI, the designated officer will be the Chief Executive Officer and his or her designate and in the case of the City the designated officer will be the City Treasurer and his or her designate or the General Manager of Corporate Services and his or her designate. The designated officers will meet as often as the Parties reasonably deem necessary during the Negotiation Period in order to gather and furnish to each other Party all information with respect to the matter in issue which the Parties believe to be appropriate and germane in connection with its resolution. The specific format for those discussions will be left to the discretion of the designated officers but may include the preparation of agreed upon statements of fact or written statements of position furnished to each other Party.

7.2.2 The period for negotiation (the "**Negotiation Period**") will begin on the day that the recipient receives the Dispute Notice and will end on the earlier of:

7.2.2.1 the date that the designated officers conclude in good faith that amicable resolution through continued negotiation of the matter in issue is not likely to occur; or

7.2.2.2 the fourteenth day after the first day of the Negotiation Period.

7.2.3 The negotiations and other settlement efforts of the Parties under Section 7.2 will, in all respects, be kept confidential and will be strictly without prejudice. All information provided, documents disclosed or statements made in the course of those negotiations and settlement efforts, including, without limitation, any admission, view, suggestion, notice, response, discussion, position or settlement proposal, will be held in strictest confidence among the Parties and, unless otherwise discoverable, will not be subject to disclosure through discovery or any other process, and will not be relied upon by any Party and will not be admissible into evidence for any purpose, including impeaching credibility, in any subsequent proceeding except as required by law, or to enforce any settlement agreement reached between the Parties.

### 7.3 Optional Facilitated Negotiation

At the end of the Negotiation Period, if the Dispute is still not resolved, the Dispute will proceed to arbitration under Section 7.4 unless one Party (the "**Requesting Party**") requests a further specified period for facilitated negotiation (the "**Facilitated Negotiation Period**"). The Facilitated Negotiation Period will not exceed fourteen days from the date following the end of the Negotiation Period. Any Facilitated Negotiation Period will be chaired and administered by a sole facilitator (the "**Facilitator**"). The Requesting Party will provide the other Party (the "**Non-Requesting Party**") a list of three qualified persons to act as the Facilitator, and the Non-Requesting Party will choose a Facilitator from such list. The costs of the Facilitator will be borne equally by the Parties. The specific format for the negotiations during the Facilitated Negotiation Period will be left to the discretion of the Parties. The Facilitator will be provided with all materials exchanged between the Parties under Section 7.2. The provisions of Section 7.2.3 will apply *mutatis mutandis* to the negotiations and other settlement efforts of the Parties under this Section 7.3.

### 7.4 Arbitration

7.4.1 All Disputes not resolved pursuant to Section 7.2 or Section 7.3 will be determined by a sole arbitrator (the "**Arbitrator**") under the *Arbitration Act, 1991* (Ontario) (the "**Arbitration Act**"). In addition:

7.4.1.1 Section 7(2) of the Arbitration Act will not apply to the arbitration of a Dispute;

7.4.1.2 the Arbitrator will any person on whom the Parties can agree. If the Parties cannot agree, the Arbitrator will be appointed by a judge of the Superior Court of Justice of Ontario on the application of any Party on notice to the other Party. No individual will be appointed as Arbitrator unless he or she agrees in writing to be bound by the provisions of this Article 7;

7.4.1.3 the law of Ontario will apply to the substance of all Disputes;

7.4.1.4 the arbitration will take place in the City of Brantford unless otherwise agreed in writing by the Parties;

7.4.1.5 the language to be used in the arbitration will be English;

7.4.1.6 the Arbitrator, after giving the Parties an opportunity to be heard, will determine the procedures for the arbitration of the Dispute, provided that those procedures will include an opportunity for written submissions and responses to written submissions by or on behalf of all Parties, and may also include an opportunity for exchange of oral argument and any other procedures as the Arbitrator considers appropriate. However, if the Parties agree on a code of procedures or on specific matters of procedure, that agreement will be binding on the Arbitrator;

7.4.1.7 the Arbitrator will have the right to determine all questions of law and jurisdiction, including questions as to whether a Dispute is arbitrable, and will have the right to grant legal and equitable relief including permanent and interim injunctive relief, and final and interim damages awards. Subject to Section 7.4.1.10, Arbitrator will also have the discretion to award costs of the arbitration, including reasonable legal fees and expenses, reasonable experts' fees and expenses, reasonable witnesses' fees and expenses, and pre-award and post-award interest and costs, provided that the Arbitrator will not make an award of costs on a distributive basis;

7.4.1.8 the Parties intend, and will take all reasonable action necessary or desirable to ensure, that there be a speedy resolution to any Dispute, and the Arbitrator will conduct the arbitration of the Dispute with a view to making a determination and order as soon as possible;

7.4.1.9 the Parties desire that any arbitration should be conducted in strict confidence and that there will be no disclosure to any Person of the existence or any aspect of a Dispute except as is necessary for the resolution of the Dispute. Any proceedings before the Arbitrator will be attended only by those Persons whose presence, in the opinion of any Party or the Arbitrator, is reasonably necessary for the resolution of the Dispute. All matters relating to, all evidence presented to, all submissions made in the course of, and all documents produced in accordance with, an arbitration under this Article, as well as any arbitral award, will be kept confidential and will not be disclosed to any Person without the prior written consent of all the Parties except as required in connection with an application of a Party under Section 46 or Section 50 of the Arbitration Act, by Applicable Law, or by an order of an Arbitrator;

7.4.1.10 the fees of the Arbitrator will be paid equally by the Parties; and

7.4.1.11 subject to Section 44 of the Arbitration Act, the Arbitrator's determination of a Dispute will be final and binding and there will be no appeal of that determination on any ground.

**7.5 Interim Relief**

7.5.1 Prior to the appointment of the Arbitrator, the Parties may apply to the courts for interim relief.

7.5.2 At the request of either Party, the Arbitrator may take any interim measures that the Arbitrator considers necessary in respect of the Dispute, including measures for the preservation of assets, the conservation of goods or the sale of perishable goods. The Arbitrator may require security for the costs of those measures.

## ARTICLE 8
## GENERAL PROVISIONS

**8.1 Notices**

Any Communication must be in writing and either:

8.1.1 delivered personally or by courier;

8.1.2 sent by prepaid registered mail; or

8.1.3 transmitted by facsimile, e-mail or functionally equivalent electronic means of transmission, charges (if any) prepaid.

Any Communication must be sent to the intended recipient at its address as follows:

to The Corporation of the City of Brantford at:

City Hall
100 Wellington Square
P.O. Box 818
Brantford, Ontario
N3T 5R7

Attention: City Clerk
Tel No.: (519) 759 – 4150
Facsimile No.: (519) 759 – 7840

to Brantford Power Inc. at:

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

Attention: CEO and President
Tel No.: (519) 751-3522 Ext. 3226

Facsimile No.: (519) 753-3369

or at any other address as any Party may at any time advise the others by Communication given or made in accordance with this Section 8.1. Any Communication delivered to the Party to whom it is addressed will be deemed to have been given or made and received on the day it is delivered at that Party's address, provided that if that day is not a Business Day then the Communication will be deemed to have been given or made and received on the next Business Day. Any Communication sent by prepaid registered mail will be deemed to have been given or made and received on the fifth Business Day after which it is mailed. If a strike or lockout of postal employees is then in effect, or generally known to be impending, every Communication must be delivered personally or by courier or transmitted by facsimile, e-mail or functionally equivalent electronic means of transmission. Any Communication transmitted by facsimile, e-mail or other functionally equivalent electronic means of transmission will be deemed to have been given or made and received on the day on which it is transmitted; but if the Communication is transmitted on a day which is not a Business Day or after 5:00 p.m. (local time of the recipient), the Communication will be deemed to have been given or made and received on the next Business Day.

**8.2 Severability**

Each Section of this Agreement is distinct and severable. If any Section of this Agreement, in whole or in part, is or becomes illegal, invalid, void, voidable or unenforceable in any jurisdiction by any court of competent jurisdiction, the illegality, invalidity or unenforceability of that Section, in whole or in part, will not affect:

8.2.1 the legality, validity or enforceability of the remaining Sections of this Agreement, in whole or in part; or

8.2.2 the legality, validity or enforceability of that Section, in whole or in part, in any other jurisdiction.

**8.3 Submission to Jurisdiction**

Without prejudice to the ability of any Party to enforce this Agreement in any other proper jurisdiction, each of the Parties irrevocably and unconditionally submits and attorns to the non-exclusive jurisdiction of the courts of the Province of Ontario to determine all issues, whether at law or in equity, arising from this Agreement. To the extent permitted by Applicable Law, each of the Parties:

8.3.1 irrevocably waives any objection, including any claim of inconvenient forum, that it may now or in the future have to the venue of any legal proceeding arising out of or relating to this Agreement in the courts of that Province or that the subject matter of this Agreement may not be enforced in those courts;

8.3.2 irrevocably agrees not to seek, and waives any right to, judicial review by any court which may be called upon to enforce the judgment of the courts referred to in this Section 8.3, of the substantive merits of any suit, action or proceeding; and

8.3.3 to the extent a Party has or may acquire any immunity from the jurisdiction of any court or from any legal process, whether through service or notice, attachment before judgment, attachment in aid of execution, execution or otherwise, with respect to itself or its property, that Party irrevocably waives that immunity in respect of its obligations under this Agreement.

### 8.4 Amendment and Waiver

No amendment, discharge, modification, restatement, supplement, termination or waiver of this Agreement or any Section of this Agreement is binding unless it is in writing and executed by the Party to be bound. No waiver of, failure to exercise or delay in exercising, any Section of this Agreement constitutes a waiver of any other Section (whether or not similar) nor does any waiver constitute a continuing waiver unless otherwise expressly provided.

### 8.5 Further Assurances

Each Party will, at that Party's own cost and expense, execute and deliver any further agreements and documents and provide any further assurances, undertakings and information as may be reasonably required by the requesting Party to give effect to this Agreement and, without limiting the generality of this Section 8.5, will do or cause to be done all acts and things, execute and deliver or cause to be executed and delivered all agreements and documents and provide any assurances, undertakings and information as may be required at any time by all Governmental Authorities having jurisdiction over the affairs of a Party or as may be required at any time under Applicable Law.

### 8.6 Assignment and Enurement

Neither this Agreement nor any right or obligation under this Agreement may be assigned by any Party without the prior written consent of the other Parties. This Agreement enures to the benefit of and is binding upon the Parties and their respective successors and permitted assigns.

### 8.7 Survival

8.7.1 The indemnities set forth in Article 6 will survive and apply to any claim for indemnification that arose prior to the expiration of the Term or earlier termination of this Agreement in accordance with Section 2.3 (the "**Termination Date**"); provided that no any claim for indemnification may be made by any Party unless that claim is made within 2 years following the Termination Date.

8.7.2 Section 4.2.2 and Section 4.2.3 will survive the Termination Date and remain in full force and effect for a period of 2 years following the Termination Date.

### 8.8 Counterparts

This Agreement may be executed and delivered by the Parties in one or more counterparts, each of which will be an original, and each of which may be delivered by facsimile, e-mail or other functionally equivalent electronic means of transmission, and those counterparts will together constitute one and the same instrument.

### 8.9 Electronic Signatures

Delivery of this Agreement by facsimile, e-mail or other functionally equivalent electronic means of transmission constitutes valid and effective delivery.

**[THE REMAINDER OF THIS PAGE IS INTENTIONALLY LEFT BLANK]**

Each of the Parties has executed and delivered this Agreement as of the date noted at the beginning of this Agreement.

**THE CORPORATION OF THE CITY OF BRANTFORD**

Per: ______________________________
Name: Chris Friel
Title: Mayor

Per: ______________________________
Name: Lori Wolfe
Title: City Clerk

**BRANTFORD POWER INC.**

Per: ______________________________
Name: Scott Saint
Title: Chair of the Board

Per: ______________________________
Name: Heather Wyatt
Title: Corporate Secretary

## SCHEDULE A
## DEFINED TERMS

1. **Incorporation by Reference**

All capitalized terms used in this Schedule A and not defined have the meanings set forth in the Agreement.

2. **Defined Terms**

In this Schedule A, the following terms have the following meanings:

(a) "**BPI Allocation**" at a particular time means, in respect of FAC Services, the percentage resulting from dividing the FAC Services provided by the City to BPI under the terms of the Agreement at such time by the aggregate FAC Services provided by the City to itself and/or its Affiliates, the whole as determined by the City from time to time.

(b) "**CRA**" means the Canada Revenue Agency;

(c) "**EI**" means the employment insurance program established under Canada's *Employment Insurance Act*;

(d) "**EFT**" means the electronic exchange or transfer of funds between one or more bank accounts within a single financial institution or across multiple financial institutions;

(e) "**EHT**" means the employer health tax levied under Ontario's *Employer Health Tax Act*;

(f) "**FTE**" means a unit of measurement of the workload of an Employee on a scale from 0 to 1.0;

(g) "**JD Edwards Financial System**" means Oracle's JD Edwards EnterpriseOne accounting software licensed to the City.

(h) "**OMERS**" means the Ontario Municipal Employees Retirement System continued under the *Ontario Municipal Employees Retirement System Act, 2006*;

(i) "**OHS**" means Ontario's *Occupational Health and Safety Act*; and

(j) "**WSIB**" means Ontario's Workplace Safety and Insurance Board established under Ontario'*s Workplace Safety and Insurance Act, 1997.*

## SCHEDULE A-1
## ACCOUNTS PAYABLE

1. **Full Description of Service**

The City will provide the following accounts payable services on a bi-weekly basis:

(a) processing and reviewing of accounts payable batches to verify payee and signing authority levels;

(b) posting accounts payable batches;

(c) maintaining vendor files (set-up vendor profiles, addresses, EFT banking information);

(d) responding to third party vendors with respect to inquiries made regarding invoice payment status;

(e) tracing payments;

(f) matching of source documents with cheque/electronic funds transfer copy; and

(g) mailing cheques and sending electronic funds transfer payments.

2. **Service Standards**

Accounts payable will be processed in accordance with invoice terms if third party invoices are provided at least two weeks prior to their respective due dates. Cheque runs will be processed at least on a bi-weekly basis.

BPI will be required to use accounting software that will be fully compatible with the City's accounting software throughout the Term, as such accounting software may be updated or replaced by the City from time to time. The Parties acknowledge that the City uses the JD Edwards Financial System as its accounting software as of the date of the Agreement.

3. **Cost Driver**

Number of line items processed.

4. **Estimated BPI Allocation for the First Year in the Term**

BPI Allocation: 14.4%

5. **Theory or Formula used to determine Cost Driver**

(A / B)

Where:

A = number of BPI line items processed; and

B = total number of line items processed.

A discount rate of 25% will be applied to all line items that are partially processed by a department within the City prior to final processing by the City's Finance department.

6. **<u>Total Estimated Cost of Service For the First Year of the Term</u>**

| | |
|---|---|
| Accounts Payable Processing | 48,718 |
| Direct out of pocket expenses: | As applicable |
| Special Projects | As determined by City on per project basis |
| **Estimated Annual Costs** | **$48,718** |

7. **<u>Monthly Charge Calculation</u>**

(A x (B / C)) / D + E

Where:

A = fully allocated accounts payable budget;

B = BPI accounts payable lines processed;

C = total accounts payable lines processed;

D = 12; and

E = direct out of pocket expenses, if any.

**SCHEDULE A-2**
**PAYROLL**

1. **Full Description of Service**

The City will provide payroll processing services on a bi-weekly, monthly, quarterly and annual basis.

(a) On a bi-weekly basis, the City will:

(i) process BPI's payroll;

(ii) post all payroll charges for wages and benefits to BPI's general ledger;

(iii) prepare payroll remittances for various agencies and groups including unions, Governmental Authorities, OMERS, the United Way and social committees;

(iv) submit direct deposit files to BPI's bank;

(v) calculate all retroactive payroll payments;

(vi) prepare print files for direct deposits;

(vii) complete Service Canada's "Record of Employment" form for BPI Employees on an as needed basis;

(viii) correspond with various third parties in connection with payroll processing activities on an as needed basis, including employees, managers, timekeepers, Governmental Authorities and OMERS; and

(ix) work with human resources department to report all applicable employee terminations and leave periods to OMERS.

(b) On a monthly basis, the City will process and submit monthly returns for EHT, WSIB and OMERS.

(c) On a quarterly basis, the City will assist BPI in complying with certain regulatory requirements promulgated by OMERS with respect to its Employees who are designated as being on an unpaid leave of absence, offering the ability to make OMERS contributions in order to attempt to maximize such Employees' credited service for OMERS purposes.

(d) On a yearly basis, the City will:

(i) calculate BPI's corporate salary and benefit budgets with information provided by BPI;

(ii) reconcile Manulife benefit billings to charges in BPI's general ledger;

(iii) process and file T4s, T4As, T4ANRs on BPI's behalf with the Canada Revenue Agency;

(iv) maintain current rate information from third party agencies, including Federal EI, WSIB, EHT, and OMERS;

(v) complete and file OMERS Form 119s (Pension Records);

(vi) work with third party actuaries on post retirement benefit information for RFP purposes and for the purposes of completing the applicable notes to BPI's annual financial statements;

(vii) reconcile loans made to Employees in connection with information technology purchases; and

(viii) prepare costing analysis during collective agreement negotiations.

2. **Service Standards**

Payroll services will be provided in accordance the standards set forth under Applicable Law and the regulations promulgated by applicable Governmental Authorities such as the Canada Revenue Agency, OMERS and WSIB.

BPI will be required to use accounting software that will be fully compatible with the City's accounting software throughout the Term, as such accounting software may be updated or replaced by the City from time to time. The Parties acknowledge that the City uses the JD Edwards Financial System as its accounting software as of the date of the Agreement.

3. **Cost Driver**

Yearly Average FTE.

4. **Estimated BPI Allocation for the First Year in the Term**

BPI Allocation: 4.08%

5. **Theory or Formula used to determine Cost Driver**

(A / B)

Where:

A = BPI yearly average FTE; and

B = total yearly average FTE.

6. **Total Estimated Cost of Service For the First Year of the Term**

| | |
|---|---|
| Cost of Service | $10,335 |
| Special Projects | As determined by City on a per project basis |
| Direct out of pocket expense: | As applicable |
| Estimated Annual Costs | **$10,335** |

7. **Monthly Charge Calculation**

(A x (B / C)) / D + E

Where:

A = fully allocated payroll budget;

B = BPI yearly average FTE;

C = total yearly average FTE;

D = 12; and

E = direct out of pocket expenses, if any.

## SCHEDULE A-3
## PURCHASING

8. **Full Description of Service**

The City will provide purchasing/purchasing consulting services on an as requested basis in connection with the procurement of goods and services from third party vendors by BPI. The City will also assist BPI in developing a purchasing and procurement policy.

9. **Service Standards**

Services will be supplied on an as requested basis within a reasonable time frame.

10. **Cost Driver**

Time (measured in minutes).

11. **BPI Allocation**

Not applicable.

12. **Total Estimated Cost of Service For the First Year of the Term**

| Estimated Hourly Charge out Rate | |
|---|---|
| Purchasing Manager | $109 |
| Purchasing Supervisor | $83 |
| Buyer(s) | $66 - $79 |

| Direct out of pocket expenses |
|---|
| Advertising |
| Other fees if applicable |

13. **Monthly Charge Calculation**

(A / B) x C + D

Where:

A = fully allocated purchasing budget;

B = standard working hours available;[1]

C = actual hours performed for BPI; and

D = direct out of pocket expenses, if applicable.

[1] Standard working hours available are calculated as the total working hours for the year net of vacation, statutory holidays, sick time and other similar exclusions.

## SCHEDULE A-4
## HUMAN RESOURCES

1. **Full Description of Services**

   (a) The City will provide the following human resource administration services:

   (i) Employee administration and benefits management; and

   (ii) Benefits and pension enrollment and administration for new employees and retirees.

   (b) The City will provide the following health and safety services:

   (i) health and safety related advice and guidance will be provided in connection with:

   (A) OHS compliance;

   (B) the operations of the Joint Health and Safety Committee;

   (C) accident investigations and investigations required under OHS; and

   (D) health, safety and workplace harassment training.

   (ii) WSIB claims management and administration, including accommodated and modified work programs; and

   (iii) non-occupational absence management and attendance support.

   (c) The City will provide the following employment and labour relations services:

   (i) labour relations management including collective agreement administration, dispute resolution and negotiation; employment services including preparation of job descriptions and job evaluations, recruitment services, interviewing and candidate selection;

   (ii) salary administration and pay equity analysis and administration; and

   (iii) Employee orientation, including code of conduct and accessibility awareness training.

2. **Service Standards**

   Services will be provided to standards in accordance with Applicable Law, City policy and any applicable standards set forth collective bargaining agreements between BPI and its Employees, where applicable.

3. **Cost Driver**

| **Service** | **Cost Driver** |
|---|---|
| Human Resources Administration/ Health & Safety | Yearly Average FTE |
| Employment Services & Labour Relations | Time (minutes) |
| Special Projects | As determined by the City on a per project basis |

4. **Estimated BPI Allocation for the First Year in the Term**

| **BPI Allocation** | **Cost Driver** |
|---|---|
| BPI Allocation: Human Resources Administration | 4.08% |
| Employment Services & Labour Relations | Not Applicable |

5. **Theory or Formula used to determine Cost Driver**

Yearly Average FTE:

A / B

Where:

A = yearly average BPI FTE; and

B = total yearly average FTE.

6. **Total Estimated Cost of Service**

| | |
|---|---|
| Human Resources Administration<br>Health & Safety | $39,639 |
| Employment Services & Labour Relations | $77 - $84 /hour |
| Special Projects | As determined by the City on a per project basis |

| **Direct out of pocket expenses** |
|---|
| Consulting |
| Advertising |
| Professional Services |
| Surveys |
| Recruitment & Testing |

7. **Monthly Charge Calculation**

(a) Human Resources Administration and Health and Safety Services:

(A x (B / C)) / (D) + E

Where:

A = fully allocated human resource administration and health and safety budgets;
B = BPI yearly average FTE;
C = total yearly average FTE;
D = 12; and
E = actual direct expenses, if applicable.

(b) Employment and Labour Relations Services:

(A x (B / C)) / D + E

Where:

A = fully allocated Employment and Labour Relations budget;
B = BPI yearly average FTE;
C = total yearly average FTE;
D = 12; and
E = actual direct expenses , if applicable.

## SCHEDULE A-5
## INFORMATION TECHNOLOGY SERVICES

1. **Full Description of Service**

(a) The City will provide the following services:

(i) installing and maintaining all hardware, software and licenses;

(ii) providing support for all hardware, software and licenses;

(iii) providing, maintaining and support all networks, e-mail and internet services; and

(iv) providing network security.

(b) The City will work on special projects from time to time including systems development and web development and maintenance as discussed and agreed upon.

2. **Service Standards**

(a) Hardware, software and database communications will be available on a 24 hour basis.

(b) Response times to problem reporting will be handled as follows:

(i) an information technology support technician will respond within one Business Day for systems communications failures which causes one Employee to be unable to carry out his or her main job functions.

(ii) an information technology support technician will log and prioritize all problems other than those set forth in Section 2(b)(i) and such problems will be dealt with in such priority order.

(c) Programming requests will be handled as follows:

(i) all programming requests that are submitted to information technology support will be logged and prioritized;

(ii) small requests are handled on a combined priority and first-in-first-out basis; and

(iii) large requests will be prioritized and scheduled after discussion with BPI management and City Business Solutions Manager.

(d) New Hardware Purchases will be handled as follows:

(i) Hardware will be purchased twice a year, once in the spring and again in the fall.

(ii) Desktop personal computers and laptops will be replaced every three years in connection with a purchase made pursuant to paragraph 2(d)(i) above.

3. **Cost Driver**

| Service | Cost Driver |
|---|---|
| Information Technology Administrative Services[2] | **Core Network Services** - % of Network Users[3] |
| | **JD Edward Services** - % of JD Edwards Users |
| | **Manager of Business Solutions** – Estimated Time |
| Information Systems Brantford Power | Total Expenses |
| Web Development and Maintenance | Hourly Charge out rate |
| Special projects including systems development | Estimated cost of the project determined on a per project basis |

4. **Estimated BPI Allocation for the First Year in the Term**

| Service | BPI Allocation |
|---|---|
| Information Technology Administrative Services | **Core Network Services** – 9% |
| | **JD Edward Services** - 6% |
| | **Manager of Business Solutions** – 25% |
| Information Systems Brantford Power | 100% |
| Web Development and Maintenance | Not Applicable |
| Special projects including systems development | Not Applicable |

5. **Theory or Formula used to determine Cost Driver**

(a) Information Technology Administrative Services – Core Network Services

(A / B)

Where:

A = number of BPI network users; and

[2] Each expense in the information technology budget will have a different cost driver depending on which service the expense relates to, i.e., core network services, JD Edwards Services, Manager of Business Solutions based on estimated time.

[3] Core services includes network and internet access as well as programs used by the majority of network users.

B = total number of network users.

(b) Information Technology Administrative Services – JD Edwards Financial System

(A / B)

Where:

A = number of BPI JD Edwards Financial System users; and

B = total number of JD Edwards Financial System users.

(c) Information Technology Administrative Services – Manager of Business Solutions

(A / B)

Where:

A = number of hours spent on BPI tasks; and

B = total number of Manager of Business Solutions hours; and

(d) Website Development and Maintenance

(A /B)

Where:

A = fully allocated Web Development and Maintenance budget information; and

B = standard working hours available.[4]

6. **Total Estimated Cost of Service**

| | |
|---|---|
| Information Technology Administrative Services | $328,899 |
| Information Systems Brantford Power | $582,801 |
| Web Development and Maintenance | As determined by the City on a per project basis |
| Special Projects | As determined by the City on a per project basis |
| **Estimated Annual Costs** | **$911,700** |

[4] Standard working hours available are calculated as the total working hours for the year net of vacation, statutory holidays, sick time and other similar exclusions.

7. **Monthly Charge Calculation**

(a) Information Technology Administrative Services:

$(A \times B) + (C \times D) + ((E \times (F / G))$

Where:

A = core network services expenses;[5]

B = BPI percentage of the number of total network users;

C = JD Edwards Service expenses; [6]

D = BPI percentage of the number of total JD Edwards users;

E = budgeted salary and benefits for Manager of Business Solutions;

F = estimated number of hours spent on BPI by the Manager of Business Solutions; and

G = total number of Manager of Business Solutions hours.

(b) Web Development and Maintenance:

$A \times B$

Where:

A = hourly charge-out rate[7]; and

B = actual hours performed for BPI.

(c) All direct expenses (including Information Technology staff expenses) related to BPI will be invoiced to BPI.

[5] All expenses are based on fully allocated budget costs.
[6] All expenses are based on fully allocated budget costs.
[7] Fully allocated budgeted expenses for Website Development and Maintenance staff will be used to calculate hourly charge out rates.

**SCHEDULE A-6**
**LEGAL AND REAL ESTATE SERVICES**

1. **Full Description of Service**

(a) The City will provide the following legal services:

(i) basic legal representation and advice only;

(ii) in-house legal representation and advice to municipal departments which perform hydro services, whether directly or indirectly; and

(iii) perform searches of public registries.

(b) The City will provide the following real estate services:

(i) estimate value, obtain appraisals, declare surplus, negotiate, receive appropriate approvals and ensure closings for any required purchases on fee simple or easements;

(ii) negotiate the sale of any surplus properties through tender or listing; and

(iii) perform searches of public registries and make registrations.

2. **Service Standards**

Basic legal services will be provided consistent with a small in-house legal department on an as-needed basis. Matters which can be resolved quickly and require a minimum of research will be handled entirely in-house.

3. **Cost Driver**

Time (measured in minutes).

4. **BPI Allocation**

Not Applicable.

5. **Estimated Hourly Charge-out Rate**

| | |
|---|---|
| Director of Legal & Real Estate Services | $149 |
| Lawyer | $98 - 109 |
| Manager of Real Estate | $106 |
| Law Clerk | $80 |

| **Direct out of pocket expenses** |
|---|
| Consultation fees |
| Fees for Searches |

| |
|---|
| Electronic Services |
| Registration fees |

6. **Monthly Charge Calculation**

Charge-out rate:

(A / B) x C +D

Where:

| | | |
|---|---|---|
| A | = | fully allocated legal and real estate budget; |
| B | = | Standard working hours available;[8] |
| C | = | actual hours performed for BPI; and |
| D | = | direct out of pocket expenses if applicable. |

[8] Standard working hours available are calculated as the total working hours for the year net of vacation, statutory holidays, sick time and other similar exclusions.

## SCHEDULE A-7
## MAILRUN

1. **Full Description of Service**

The City will perform the following mailrun services:

(a) twice weekly courier run from City Hall to 84 Market Street, 84 Market to 220 Colborne and 220 Colborne Street to City Hall; and

(b) sorting, delivery and pick up of interoffice and incoming/outgoing mail.

2. **Service Standards**

Twice weekly pick up and drop off. The twice weekly courier run is for regular office mail and interoffice mail and does not include the pickup of customer service billings.

3. **Cost Driver**

Market.

4. **BPI Allocation**

Not Applicable.

5. **Theory or Formula used to determine Cost Driver**

Not applicable

6. **Monthly Charge Calculation**

A x B

Where:

A = $40; and

B = number of days.

## SCHEDULE A-8
## POSTAGE SERVICE

1. **Description of Service**

The City will process and stamp all outgoing mail with the required amount of postage.

2. **Service Standards**

Outgoing mail will be stamped and mailed daily.

3. **Cost Driver**

Pieces of outgoing mail.

4. **BPI Allocation**

Not Applicable.

5. **Theory or Formula used to determine Cost Driver**

A /B

Where:

| | | |
|---|---|---|
| A | = | fully allocated postage budget; and |
| B | = | total number of outgoing pieces of mail. |

6. **Estimated Cost of Service for the first year**

| | |
|---|---|
| Cost per piece of mail (excluding cost of postage) | **$0.14** |

7. **Monthly Charge Calculation**

(a) Cost of postage: actual cost of postage for BPI Postage cost will include 50% of customer service postage cost until utility bills are split and mail can be divided.

(b) Handling charge:

A x (B / C)

Where:

| | | |
|---|---|---|
| A | = | number of pieces of outgoing BPI mail;[9] |
| B | = | fully allocated postage budget; and |
| C | = | total number of outgoing pieces of mail. |

[9] Number of pieces of mail will include 50% of customer service until utility bills are split and mail can be divided.

# SCHEDULE A-9
# TELEPHONE SERVICE

1. **Full Description of Service**

The City will perform the following services with respect to telephone lines within the city trunk service:

(a) handle inquiries regarding telephone bills;

(b) arrange for service on telephone lines;

(c) provide switchboard service; and

(d) process administrative changes to telephone system (e.g., adding and deleting telephone extensions for lines within the trunk service).

The following phone numbers will be included in City trunk service: all extensions under 759-4150 (353 extensions) and all BPI telephone numbers as listed; 750-0053, 751-2144, 752-1631, 753-2649, 753-6130, 753-7402, 753-8143, 753-9668, 759-6177, 753-4788 and 753-9206.

2. **Service Standards**

A fully functional telephone system with voice mail will be provided including system support and repair. The telephone system will be administered by the City Clerk's Division of the Corporate Services Department of the City for all trunk lines only. Brantford Power will service all lines not included in the city trunk lines.

3. **Cost Driver**

Number of telephone lines.

4. **Estimated BPI Allocation for the First Year in the Term**

BPI Allocation: 15.11%

5. **Theory or Formula used to determine Cost Driver**

A / B

Where:

| | | |
|---|---|---|
| A | = | number of BPI telephone lines; and |
| B | = | total number of telephone lines. |

6. **Estimated Cost of Service for the first year**

| | |
|---|---|
| Estimated Cost of Service | $16,124 |
| Special Projects | As determined by the City on a per project basis |
| **Direct out of pocket expense:** | |
| Cost of BPI Lines (excluding 759-4150) | To be determined by the City |
| Cost of BPI R&M for numbers as listed above (excluding 759-4150) | To be determined by the City |

7. **Monthly Charge Calculation**

(a) Telephone Management:

((A x B x (C/D))) / E

Where:

A = Estimated annual time spent on telephone management

B = fully allocated salary and benefits budget for telephone coordinator;

C = number of BPI telephone trunk lines;

D = total number of telephone trunk lines; and

E 12.

(b) Switchboard:

(A x (B/C)) / D

Where:

A = fully allocated City Hall Switchboard receptionist salary and benefits budget;

B = average number of BPI switchboard phone calls;

C = total number of switchboard calls; and

D = 12.

(c) Telephone Trunk Line Costs:

(A x (B/C)) + D

Where:

| | | |
|---|---|---|
| A | = | actual switchboard line costs; |
| B | = | number of BPI telephone extensions; |
| C | = | total number of extensions; and |
| D | = | actual BPI long distance costs. |

(d) Telephone Maintenance & Repair Fee:

(A x (B/C)) + D

Where:

| | | |
|---|---|---|
| A | = | actual maintenance fees; |
| B | = | number of BPI telephone trunk lines; |
| C | = | total number of telephone trunk lines; and |
| D | = | actual direct costs, if applicable. |

**SCHEDULE A-10**
**INSURANCE AND RISK MANAGEMENT**

1. **Full Description of Service**

The City perform the following insurance related services on behalf of BPI:

(a) placement and management of general comprehensive liability insurance (including directors and officers insurance), property insurance and vehicle insurance;

(b) claims administration and adjusting services;

(c) assistance in developing risk management procedures; and

(d) advice on contractual arrangements.

2. **Service Standards**

(a) Liability and property insurance will be obtained with the level of coverage to be determined by BPI's board of directors. The City Clerk shall provide in consultation with the Insurance Department advice and assistance to BPI's board of directors in connection with such policy limits. Claims administration will be undertaken by the City Clerk. Adjusting services for claims will be provided as necessary. The City will provide updates on matters of risk management, events, and occurrences to BPI.

(b) The City will be named as an additional insured on all insurance policies where such coverage is available

3. **Cost Driver**

Percentage of insurance premiums.

4. **Estimated BPI Allocation for the First Year in the Term**

BPI Allocation: 6.15%

5. **Theory or Formula used to determine Cost Driver**

(A/B)

Where:

A = BPI insurance premiums;

B = total insurance premiums;[10]

6. **<u>Estimated Cost of Service for first year</u>**

| | | |
|---|---|---|
| Estimated Cost of Service | | $15,654 |
| Special Projects | | As determined by the City on a per project basis |
| **Direct out of pocket expense:** | | |
| Estimated BPI Insurance Premium | $125,713 | |
| Mearie Conference (2012 costs) | $1,766 | $127,479 |
| **Estimated Annual Costs** | | **$143,133** |

7. **<u>Monthly Charge Calculation</u>**

(A x (B/C)) /D + E

Where:

A = fully allocated insurance and risk management budget;
B = BPI insurance premiums;
C = total insurance premiums;
D = 12; and
E = direct out of pocket expenses, if applicable.

[10] The insurance budget will be written on a true risk formula which will not include any premiums credits and/or rebates which may be applied to a particular policy. No adjustments will be made due to retroactive assessments or supplemental premium adjustments.

**SCHEDULE A-11**
**RECORDS MANAGEMENT**

1. **Full Description of Service**

   The City will provide the following records management services:

   (a) maintain file plans and retention schedules;

   (b) transfer, retrieve and destroy inactive records;

   (c) records delivery and pick-up;

   (d) records management training on versatile software; and

   (e) production of reports for records management as required.

2. **Service Standards**

   All requests will be completed in order of priority. BPI is responsible to provide its own banker boxes.

3. **Cost Driver**

   Market price.

4. **BPI Allocation**

   Not Applicable.

5. **Theory or Formula used to determine Cost Driver**

   Not applicable

6. **Estimated Cost of Service for the first year**

| **Pricing Schedule** | |
|---|---|
| **Storage** | $.25/cubic feet / month |
| **Transfers** | $2.42/box, $3.45/file |
| **Retrievals** | $2.42/box, $3.45/file |
| **Refiles** | $2.42/box, $3.45/file |
| **Destructions** | $2.42/box(picking fee) + $5.00 (actual cost of shredding) |

| | |
|---|---|
| **Delivery/pickup** | $16.50 first box<br>$2.75/each additional box |
| **Special Project** | As determined by the City on a per project basis |

| **Total Cost of Service Based on current boxes in storage:** | | |
|---|---|---|
| BPI occupies 14 bays | x 100 boxes | = 1,400 boxes |
| Each box is 1.20 cubic feet | | |
| Total Boxes | 1,400 | |
| x 1.20 cubic feet | 1,680 | |
| x $0.25 cubic feet/month | $420 | |
| **Total Estimated Yearly Storage Costs** | **$5,040** | |

7. **Monthly Charge Calculation**

(a) Cost of Transfers, Retrievals and Destructions

A x B

Where:

A = actual number of files or boxes; and
B = cost as per pricing schedule.

(b) Cost of Storage

A x B

Where:

A = estimated number of cubic feet; and

B = cost as per pricing schedule.

## SCHEDULE A-12
## FACILITY ASSET MANAGEMENT (PROPERTY MANAGEMENT)

1. **Full Description of Service**

The City will provide all aspects of property management relating to 84 Market St, 220 Colborne Street and 400 Grand River Ave, including janitorial, elevator, mechanical, electrical, plumbing, security systems, window cleaning, mats, pest control, life safety, fire plans, parking lot maintenance, snow removal, landscaping and general maintenance and repairs, handling legislative inspections and condition assessments.

2. **Service Standards**

(a) Services will be available during normal City corporate operating hours and will be available for emergency or urgent situations.

(b) Maintain the physical buildings, grounds and common areas to the current standards for a Class B building.

(c) Leasehold improvements by the tenant are the sole responsibility of the tenant. All work undertaken by the tenant requires the approval of the City.

(d) Telephone and information technology services do not form part of property management services.

(e) BPI will remain responsible at all times for any loss and/or damage caused by it or its invitees.

3. **Cost Driver**

Administration - Estimated percentage of time spent on BPI occupied property.

Repair & Maintenance: Square footage of BPI occupied property.

4. **Estimated BPI Allocation for the First Year in the Term**

BPI Allocation: 2.52%

5. **Theory or Formula used to determine Cost Driver**

(a) Administration

(A / B)

Where:

A = estimated time spent on BPI occupied property; and

B = total time.

(b) Repairs and Maintenance

(A / B)

Where

A = BPI Square footage of occupied property; and

B = total square footage of property.

6. **Estimated Cost of Service for the first year**

| Property Address | Property Management Admin | 2012 Budget R & M | Total |
|---|---|---|---|
| 84 Market Street | $10,227 | $66,508 | $76,735 |
| 400 Grand River Ave | $7,523 | $105,307 | $112,830 |
| 220 Colborne Street | $1,899 | $8,114 | $10,013 |
| Special Projects | | | As determined by the City on a per project basis |
| **Total Cost of Service** | $19,649 | $ 179,929 | **$199,578** |

7. **Monthly Charge Calculation**

(a) Administration:

(A x (B/C)) / D

Where:

A = fully allocated property management administration budget;

B = estimated time spent on BPI occupied property;

C = total time; and

| | | |
|---|---|---|
| D | = | 12. |

(b) Repairs and Maintenance:

(A x (B/C) + D

Where:

| | | |
|---|---|---|
| A | = | actual expenses; |
| B | = | BPI square foot occupied; |
| C | = | total square footage; and |
| D | = | actual direct costs, if applicable. |

## SCHEDULE A-13
## RENTAL OF FACILITIES - OFFICE SPACE

1. **General Terms of Tenancy**

   (a) The City will provide office space for Brantford Power staff.

   (b) Annual rent payment includes owner related capital and property taxes.

   (c) Leasehold improvements by the tenant are the sole responsibility of the tenant, all work undertaken by the tenant is to be approved by the Facilities Management Department.

   (d) General repair and maintenance, utilities and contracted services of the building is billed based on actual costs - refer to Facility Asset Management section for charges related to these buildings.

2. **Service Standards**

   Maintain the building to the current standards for a Class B building.

3. **Cost Driver**

   Market.

4. **Estimated BPI Allocation for the first year**

   220 Colborne Street: 2,676.74 sq ft or 2.5%

   84 Market Street: 8618 sq ft or 38.6%

5. **Theory or Formula used to determine Cost Driver**

   Not applicable.

6. **Estimated Cost of Service for the first year**

| Property Address | Sq ft | Rent per sq ft | Annual Rent |
|---|---|---|---|
| 220 Colborne Street | 2,676.74 | $12.00 | $32,121 |
| 84 Market Street | 8,618 | $12.00 | $103,416 |
| **Total Rent - Office Space** | | | **$ 135,537** |

7. **Monthly Charge Calculation**

Rent:

(A x B)

Where:

| | | |
|---|---|---|
| A | = | Rent per square foot; and |
| B | = | square feet occupied by BPI. |

**SCHEDULE A-14**
**RENTAL OF FACILITIES - OFFICE/WAREHOUSE/VEHICLE STORAGE**

1. **General Terms of Tenancy**

   (a) Description of Facility: Warehouse Vehicle Storage Facility with drive through vehicle storage with multiple drive in doors at both ends of facility, high ceilings, sloped floors with drains.

   (b) Office space with warehouse finished office area with HVAC system.

   (c) Warehouse Storage Area with, 12' clear ceiling height.

   (d) Outside storage with designated asphalt surfaced area for outside storage.

   (e) General repair and maintenance, utilities and contracted services of the building will be billed based on actual costs: refer to Facility Asset Management section for charges related to these buildings.

   (f) Leasehold improvements by the tenant are the sole responsibility of the tenant, all work undertaken by the tenant is to be approved by the Facilities Management Department.

2. **Service Standards**

   Maintain the building to the current standards for a Class B building.

3. **Cost Driver**

   Market.

4. **BPI Allocation**

   Not Applicable.

5. **Theory or Formula used to determine Cost Driver**

   Market

6. **Estimated Cost of Service for the first year**

| 400 Grand River Ave. | Sq ft | Rent per sq ft | Annual Rent |
|---|---|---|---|
| Warehouse Vehicle Storage facility | 11,288 | $5.50 | $62,084 |
| Office Area | 828 | $8.00 | $6,624 |

| | | | |
|---|---|---|---|
| Warehouse Storage Area | 7,350 | $3.50 | $25,725 |
| Outside Storage | 112,000 | $0.50 | $56,000 |
| **Total Rent** | | | **$150,433** |
| Property Taxes | | | $52,500 |
| **Grand Total** | | | **$202,933** |

7. **<u>Monthly Charge Calculation</u>**

Rent:

(A x B) + C

Where:

| | | |
|---|---|---|
| A | = | Rent per square foot; |
| B | = | square feet occupied by BPI; and |
| C | = | property taxes, if applicable. |

**SCHEDULE A-15**
**TREE TRIMMING**

1. **Full Description of Service**

The City will perform the following tree trimming services:

(a) create tree trimming grid and schedule of yearly tree trimming requirements;

(b) schedule and coordinate daily tree trimming requirements with third party contractors;

(c) answer incoming calls of tree trimming requests;

(d) schedule and coordinate emergency work as required; and

(e) visit work locations and assess trees.

2. **Service Standards**

The City will provide tree trimming services in accordance with Applicable Law, City policy and purchasing agreements with third party contractors.

3. **Cost Driver**

Percentage of annual BPI work orders.

4. **Estimated BPI Allocation for the First Year in the Term**

BPI Allocation: 48%

5. **Theory or Formula used to determine Cost Driver**

(A / B)

Where:

A = annual number of BPI related work orders; and
B = total number of annual work orders.

6. **Estimated Cost of Service for the first year**

| | |
|---|---|
| Tree Trimming Service | $94,909 |
| Direct Out of Pocket: | |
| Estimated Tipping fees | $500 |
| Estimated Contracted Services | $377,000 |
| Special Projects | As determined by the |

| | |
|---|---|
| | City on a per project basis |
| Total | $472,409 |

7. **Monthly Charge Calculation**

(A x (B/C)) / D + E

Where:

| | | |
|---|---|---|
| A | = | fully allocated tree maintenance budget; |
| B | = | number of annual BPI related work orders; |
| C | = | number of total annual work orders; |
| D | = | 12; and |
| E | = | direct out of pocket expenses. |

**SCHEDULE B**
**FAC SERVICES AND NON FAC SERVICES**

**FAC Services**

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## PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES

BPI purchases many services and products from third parties. Table 4.34 discloses the expenditures by vendor where the annual amount exceeded $70,000 per year, for the years 2008, 2009, 2010, 2011 and 2012.

A copy of BPI's procurement policy has been provided in Appendix C. BPI has followed this policy in the past and will continue to do so.

Table 4.34 also contains the historical Non-Affiliate Supplier information including Vendor, total amount of goods or services purchased and the procurement method used. The Table is categorized by vendor name.

## Table 4.34 - Non-Affiliate Suppliers – Over Materiality Threshold

| **2008** | | | |
|---|---|---|---|
| **Vendor Name** | **Activity** | **Amount** | **Method of Procurement** |
| ABB INC. | Electrical Supplies | $ 107,830.21 | Competitive Bids |
| BORDEN LADNER GERVAIS | Regulatory Consulting and Legal Services | $ 134,626.59 | Request For Proposals |
| CANADIAN ELECTRICAL SERVICES | Electrical Supplies | $ 425,283.74 | Competitive Bids |
| GUELPH UTILITY POLE COMPANY LT | Electrical Supplies | $ 80,308.80 | Competitive Bids |
| HD SUPPLY UTILITIES | Electrical Supplies | $ 535,778.73 | Competitive Bids |
| ITRON CANADA INC. | Electrical Supplies | $ 71,529.80 | Competitive Bids |
| MOLONEY ELECTRIC TRANSFORMERS | Electrical Supplies | $ 87,921.30 | Competitive Bids |
| NORAMCO | Electrical Supplies | $ 296,875.98 | Competitive Bids |
| **Total** | | **$ 1,740,155.15** | |
| **2009** | | | |
| **Vendor Name** | **Activity** | **Amount** | **Method of Procurement** |
| ABB INC. | Electrical Supplies | $ 97,136.02 | Competitive Bids |
| BORDEN LADNER GERVAIS | Regulatory Consulting and Legal Services | $ 168,610.42 | Request For Proposals |
| CANADIAN ELECTRICAL SERVICES | Electrical Supplies | $ 76,516.92 | Competitive Bids |
| GUELPH UTILITY POLE COMPANY LT | Electrical Supplies | $ 119,553.84 | Competitive Bids |
| HD SUPPLY UTILITIES | Electrical Supplies | $ 312,503.11 | Competitive Bids |
| WESTBURNE/RUDDY ELECTRIC | Electrical Supplies | $ 182,412.96 | Competitive Bids |
| **Total** | | **$ 956,733.27** | |
| **2010** | | | |
| **Vendor Name** | **Activity** | **Amount** | **Method of Procurement** |
| ABB INC. | Electrical Supplies | $ 259,400.00 | Competitive Bids |
| BEL VOLT SALES LTD. | Electrical Supplies | $ 72,434.47 | Competitive Bids |
| BORDEN LADNER GERVAIS LLP | Regulatory Consulting and Legal Services | $ 70,688.97 | Request For Proposals |
| ELSTER CANADIAN METER | Electrical Supplies - Smart Meters | $ 710,557.36 | Competitive Bids |
| GUELPH UTILITY POLE COMPANY LT | Electrical Supplies | $ 171,319.72 | Competitive Bids |
| HD SUPPLY UTILITIES | Electrical Supplies | $ 167,185.76 | Competitive Bids |
| LAPRAIRIE INC. | Electrical Supplies | $ 96,276.74 | Competitive Bids |
| NORAMCO | Electrical Supplies | $ 311,747.13 | Competitive Bids |
| WESTBURNE/RUDDY ELECTRIC | Electrical Supplies | $ 73,812.81 | Competitive Bids |
| **Total** | | **$ 1,933,422.96** | |
| **2011** | | | |
| **Vendor Name** | **Activity** | **Amount** | **Method of Procurement** |
| CANADA POWER PRODUCTS | Electrical Supplies | $ 82,090.00 | Competitive Bids |
| GUELPH UTILITY POLE COMPANY LT | Electrical Supplies | $ 159,936.00 | Competitive Bids |
| HD SUPPLY UTILITIES | Electrical Supplies | $ 341,852.22 | Competitive Bids |
| LAPRAIRIE INC. | Electrical Supplies | $ 199,201.13 | Competitive Bids |
| NORAMCO | Electrical Supplies | $ 91,868.54 | Competitive Bids |
| **Total** | | **$ 874,947.89** | |
| **2012** | | | |
| **Vendor Name** | **Activity** | **Amount** | **Method of Procurement** |
| ABB INC. | Electrical Supplies | $ 281,519.00 | Competitive Bids |
| GUELPH UTILITY POLE COMPANY LT | Electrical Supplies | $ 123,712.00 | Competitive Bids |
| HD SUPPLY UTILITIES | Electrical Supplies | $ 426,333.70 | Competitive Bids |
| LAPRAIRIE INC. | Electrical Supplies | $ 122,837.05 | Competitive Bids |
| NORAMCO | Electrical Supplies | $ 211,593.72 | Competitive Bids |
| **Total** | | **$ 1,165,995.47** | |

# APPENDIX C

# BPI PURCHASING POLICY

# BRANTFORD POWER INC.
# POLICY 1 -- PURCHASING

DATE APPROVED: SEPTEMBER 27, 2012

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# <u>CHAPTER 1</u>
# <u>INTERPRETATION</u>

1.01 Statement of Principle

In acquiring goods and services for Brantford Power Inc. ("BPI"), BPI requires processes to ensure that operating departments will receive the goods and services they require in sufficient quality and quantity for their needs, acquired with integrity, fairness, equality, and transparency through efficient means that produce prudently incurred costs for the ratepayer.

BPI has determined as a matter of policy that the prudently incurred costs for the ratepayer is most often received when competitive acquisition processes are used. For that reason, competitive acquisition will be the general rule and will be departed from only in accordance with specific exceptions set forth in this policy.

1.02 Goals of the Policy

The goals of the Purchasing Policy are as follows:

(a) To ensure accountability and transparency while protecting the financial best interest of BPI;
(b) To encourage competitive bidding for the acquisition and disposal of goods and services where practicable;
(c) To ensure fair treatment and respectful business practice to all bidders;
(d) To obtain efficiencies where possible by maximizing buying power through economies of scale and participating in cooperative buying groups.

1.03 Application of Policy

(a) All BPI departments and officials shall acquire goods and services in accordance with this Policy and not otherwise. No member of BPI's Board or any BPI employee shall have the right to acquire goods and services or to otherwise bind BPI in respect of the acquisition of goods and services, except in accordance with this Policy.

(b) This Policy shall apply to the acquisition of all goods and services by BPI, except for the exemptions set forth in Schedule 1. The acquisition of the goods and services listed and described in Schedule 1 shall not be subject to the requirements of this Policy, but may be subject to other policies or requirements enacted from time to time by BPI's Board of Directors.

1.04 Incorporation of Policy into Solicitations

The requirements of this Policy shall be incorporated by reference into all solicitations for goods and services acquired by the BPI.

1.05 Delegation

Where authority is given to the BPI CEO, any Director, or any other position, pursuant to this policy, such authority may be delegated to subordinate staff on such terms as the BPI CEO, applicable Director or other position, as the case may be, shall consider reasonable in the circumstances.

1.06 Definitions

In this Policy,

"Affiliates" means affiliates within the meaning of the Business Corporations Act (Ontario).

"Acquisition," "Procurement," "Buy," and "Purchase" also include obtaining the use of goods and/or services by lease, rental, and other temporary methods.

"Award" means authorization to proceed with the purchase of goods and/or services from a chosen vendor.

"Department Staff" or "Operating Department Staff" means staff of any BPI department for which goods and services are being acquired.

"Emergency" means an urgent situation that could result in serious harm to persons, substantial damage to property, or substantial interference with BPI operations. An emergency shall only be deemed to exist if:

(a) The municipal Council determines that an emergency exists; or,
(b) BPI CEO determines that an emergency exists; or
(c) The applicable Director determines that an emergency exists.

"Engineering Works" means agreements with contractors under which the contractor shall perform construction or reconstruction of roads, sewers, water works, flood control works, and bridges.

"Estimated Value of Goods and Services" means the estimated amount (excluding taxes) for budget or planning purposes in acquiring particular goods and services, which amount may be higher, lower or equal to the actual cost of the goods and services when ultimately acquired. For greater certainty, when multi-year contracts are awarded for the acquisition of goods and services, the estimated value of the goods and services for such multi-year contracts is the estimated amount to be paid for the goods and services over the entire contract, and is not limited to the amount which may be payable in any particular budget year.

"Goods" means all manner of personal property, goods, equipment, things, and rights.

"High Value" means high value within the meaning of Table One.

“Human Resources Staff” means those persons engaged by the service provider to provide humam ressources services set out in the shared services agreement between BPI and the City of Brantford

“Informal Procurement” means procurement in which there are minimal procedural requirements, and without limiting the generality of the foregoing, includes procurement in which there is no requirement to obtain competitive pricing.

“Low Value” means low value within the meaning of Table One.

“Lowest overall cost” means the cost of acquiring goods and services after the evaluation factors set forth in the Solicitation are taken into account. Such factors may include price, quality, life cycle costs and all other terms, conditions, and circumstances of the acquisition.

“Lowest Responsive Submission” means a submission in response to a solicitation which includes all required components and which shows the lowest overall cost when all evaluation factors contained in the solicitation are taken into account.

“Medium Value” means medium value within the meaning of Table One.

“Non-competitive Acquisition” means procurement which does not include any competitive process, and without limiting the generality of the foregoing, includes procurement through negotiation, sole sourcing, and single sourcing.

“Option to Buy” means the right to acquire goods upon stated terms, most often but not exclusively encountered in the context of rental, lease (but not a financing lease), or hire-purchase agreements. The exercise of an option to extend a contract for the acquisition of goods and services shall also be deemed to be the exercise of an option to buy, but only if the option to extend formed part of the original contract as awarded.

“Pre-approved Solicitation” means any solicitation implementing a project, acquisition of goods and services, or other undertaking which has been classified as a pre-approved solicitation, project, acquisition of goods and services, or other undertaking by BPI’s Board of Directors through Resolution following a report from the applicable department describing the proposed solicitation, project, acquisition of goods and services or other undertaking. The Purchasing Officer shall determine in his or her discretion whether or not any proposed solicitation matches the identification and description in the applicable Board Resolution.

“Prequalification Process” means a solicitation process in which detailed written submissions describing attributes such as experience, financial strength, education, or background, or other pertinent considerations are solicited in a Request for Prequalification.

“Procedures” means procedures developed by the Purchasing Officer pursuant to Articles 2.08(c) (Best Prac*tices for the Disposal of Goods and Equipment)*, 3.04(a) *(Best Purchasing and Acquisition Practices),* 5.03(a) *(Best Purchasing and Acquisition Practices for the Solicitation of Consulting Services)*, and 6.03(a) (*Best Practices for the Documentation of past Failures of Vendors to provide appropriate Performance)*.

“Purchasing Officer” means the person so designated by the service provider as set out in the shared services agreement between BPI and the City of Brantford;
“Purchasing Department Staff” means those persons engaged by the service provider to provide purchasing services as set out under the shared services agreement between BPI and the City of Brantford

“Pursuing litigation" means actually commencing and/or continuing a judicial proceeding.

“Responsive” means, when applied to a submission, that the submission contains each and every element required by the solicitation for the submission, and otherwise fully complies with the requirements of the solicitation.

“Request for Expressions of Interest” means a general market research tool to determine vendor interest in a proposed procurement. It is used prior to issuing another solicitation and is not intended to result in the award of a contract.

“Request for Proposals” means a competitive procurement process for obtaining unique proposals designed to meet terms of reference.

“Request for Quotations” means a competitive procurement process for obtaining bids based on defined requirements for which fixed or calculated price will be paid.

“Request for Tenders” means a competitive procurement process for obtaining defined requirements for which a clear or single solution exists.

“Services” means any and all services, and includes construction services.

“Shared Services” being services that are shared between the City of Brantford and BPI and set out in the shared services agreement between BPI and the City of Brantford

“Single Sourcing” means the procurement of a good or service from a particular vendor rather than through the solicitation of bids from other vendors who can provide the same item.

“Sole Sourcing” means the procurement of a good or service that is unique to a particular vendor and cannot be obtained from another source.

“Solicitation” means any and all forms of solicitation for goods and services by BPI, including but not limited to requests for tenders, requests for quotations, requests for proposals, requests for prequalification, requests for information, and requests for expressions of interest.

“Solicitor” means that person or those persons engaged by the service provider to provide legal services as set out in the shared services agreement between BPI and the City of Brantford

“Submission” means any and all offers, bids, or other responses to a solicitation by BPI.

“Surplus” means goods belonging to BPI of Brantford which, through obsolescence or other causes, no longer serve any useful purpose to the operating department of BPI in which the goods were used.

“Table One” means the Table One entitled “Methods through which Goods and Services may be Acquired” within Section 3.01 of this Policy.

"Threatening litigation" means transmitting a written threat to commence a judicial proceeding

“Two Envelope Method” means a procurement process in which a submission is submitted into two separate envelopes. The technical and qualitative information are submitted in the first envelope and the price information is provided in the second envelope. The second envelope is opened only if the first envelope shows the bidder to be qualified.

“Vendor” means a seller or supplier of goods and/or services.

“Working Days” means days on which the main offices of BPI are open for business.

"Unsolicited Proposal" means an offer to supply goods or services to BPI that has not been preceded by the issuance of a solicitation by BPI.

# CHAPTER 2
# GENERAL MATTERS

2.01 No Local Preference

(a) Except as set forth in (b) and (c), no local preference shall be shown or taken into account in acquiring goods and services on behalf of BPI.

(b) Where there are two responses to a solicitation for goods or services, which after evaluation appear equal in all respects, a local preference may be shown for the sole purpose of breaking the tie. In such circumstances, the "local" Vendor shall be deemed to be the Vendor whose business premises shall have the nearest geographical proximity to the point of delivery of the goods and services. For purposes of the foregoing, "business premises" mean the business premises from which the goods and services shall be supplied.

(c) Despite (a), a local preference may be shown when the intrinsic nature of the acquisition necessitates a local preference

2.02 Co-operative Purchasing Arrangements

(a) The Purchasing Officer, in consultation with BPI staff, may make cooperative purchasing arrangements with other local distribution companies, consortia of local distribution companies or similar utility providers or other public cooperatives or consortia under which particular varieties of goods and services may be acquired by BPI in conjunction with such other local distribution companies, consortia of local distribution companies or similar utility providers or other public cooperatives or consortia at a lower overall cost than they might otherwise achieve were they to proceed independently.

(b) Because the cooperative arrangements may require the cooperation of multiple organizations with differing purchasing procedures, deviations from the requirements of this Policy are permitted in such cooperative arrangements provided that the principles set forth in Chapter 1 are fully respected.

(c) Where cooperative purchasing arrangements have been effected cooperative purchasing arrangements in accordance with this section, operating departments shall acquire the particular varieties of goods and services in accordance with such cooperative arrangements and not otherwise. The Purchasing Officer shall be permitted to authorize exceptions from the foregoing in extenuating circumstances.

2.03 General Supply Contracts

(a) Where the Purchasing Officer in consultation with the BPI CEO or his/her designate perceives continuing common needs for particular goods and services for shared services, he or she may issue solicitations for the general supply of the needs of all departments of the municipality and BPI for such particular goods and services.

(b) Where a contract for the general supply of the needs of shared services for particular goods and services has been awarded in accordance with (a) above, operating departments shall acquire the particular varieties of goods and services in accordance with such cooperative arrangements and not otherwise. The Purchasing Officer shall be permitted to authorize exceptions from the foregoing in extenuating circumstances.

2.04 General Ability of the Board of Directors to overrule Procedural Requirements

(a) The BPI Board of Directors may overrule any requirement of this policy on a transaction-specific basis through resolution.

(b) The elimination of any requirement of this policy on a general or continuing basis must be approved through Board resolution, which amends this Policy.

2.05 Forms, Contracts and Documents

(a) The Purchasing Officer may develop or adopt standard forms of solicitations and other documents to be used in conjunction with the acquisition of goods and services for BPI.

(b) Documents used pursuant to (a) shall have been approved by the Solicitor.

(c) Where the Purchasing Officer has developed a standard form in accordance with (a) above, operating departments shall acquire the particular varieties of goods and services in accordance with standard forms and not otherwise, provided that the Purchasing Officer may authorize or draft minor variations therefrom as necessary.

2.06 Execution of Contracts and Documents

(a) The execution of contracts and documents in connection with the acquisition of goods and services by BPI shall be in accordance with the requirements of BPI Policy 3 – Execution of Routine Documents

(b) Employees are responsible for determining whether or not they have authority to execute documents on behalf of BPI in accordance with the foregoing.

(c) Without limiting the generality of anything else contained in this policy or the seriousness of any other contravention of this Policy, it shall be a serious contravention of this Policy for any employee to execute a contract or other document in connection with a solicitation of goods or services if the execution of such contract or other document is not in accordance with the requirements of BPI Policy 3.

2.07 Disposal of Surplus Goods and Equipment

(a) Except where otherwise required by the BPI Board of Directors for specific varieties of goods or equipment, surplus goods shall be disposed of by the Purchasing Officer in accordance with this Policy.

(b) Surplus goods shall be disposed of by any one of the following methods, ranked in order of preference as follows:

- (i) Given to another operating department within BPI ;
- (ii) Traded in as part of a replacement purchase;
- (iii) Sold by a competitive public offering process or auction;
- (iv) Offered or donated to non-profit agencies; or
- (v) Disposal of the goods by transportation to the landfill site, recycling site or other appropriate disposal facility.

(c) The Purchasing Officer in consultation with BPI's Chief Financial Officer or his/her designate may make written procedures from time to time consistent with the requirements of this Policy to reflect best practices for the disposal of surplus goods.

(d) Procedures enacted pursuant (c) shall have been approved by the Senior Leadership Team of BPI.

(e) Where the Purchasing Officer has developed procedures in accordance with (c) above, operating departments shall follow such procedures.

2.08 Persons with Disabilities

In acquiring goods and services for BPI, staff shall consider and have regard to disability accessibility issues as they may reasonably pertain to such acquisitions of goods and services

(a) Contracts for the acquisition of goods and services shall include the following elements:

- (i) that the Vendor shall comply with the Accessibility Standards for Customer Service, O. Reg. 429/07 (Appendix A) ("Regulation"), under The Accessibility for Ontarians With Disabilities Act, 2005 (AODA);
- (ii) that the Vendor shall ensure that its employees are trained on providing accessible customer services. Any training or training resources must conform to the legislated requirements under the Act; and
- (iii) that the Vendor shall maintain records of the training, including dates when training was provided, the number of employees who received training and individual training records. Where requested by BPI, the person, business or organization shall provide written proof, as well as any documentation regarding training policies, practices and procedures, to BPI.

2.09 Review of this Policy

This Policy shall be reviewed every four years.

2.10 Green Procurement

In acquiring goods and services for BPI, staff shall consider whether it is feasible to incorporate environmental considerations into solicitations for goods and services. The Purchasing Officer shall keep apprised of best purchasing practices for responsible environmental procurement, and shall bring it to the attention of operating departments wherever the same are applicable.

2.11 Unsolicited Proposals

(a) Unsolicited Proposals received by BPI shall be reviewed by the Purchasing Manager and the Director of the applicable department to determine if the proposal warrants consideration.

(b) Any Unsolicited Proposal shall not be considered if:
   - (i) It resembles a current or upcoming competitive procurement that has or will be requested;
   - (ii) It requires substantial assistance from BPI to complete the proposal
   - (iii) The goods or services are readily available from other sources
   - (iv) It is not deemed by the Director to be of sufficient value to BPI.

(c) Any Unsolicited Proposal warranting execution shall be either procured through a competitive bid process as per Table One or require Board of Directors approval to award as a single source or sole source purchase.

(d) Where a competitive bid process is undertaken for the good or service, the person submitting the Unsolicited Proposal shall not be precluded from participating in the procurement process.

2.12 Dispute Resolution

In the event any vendor involved in a procurement process with BPI presents a dispute in regards to that process, the following dispute resolution process shall be followed:

(a) The vendor indentifying the dispute shall be required to state the nature of the dispute in writing, giving full details and history of the events leading to the dispute claim, addressed to the Manager of Purchasing.

(b) The award of any contract shall not be rescinded nor the progress of any project be delayed by a request for dispute resolution unless recommended by the BPI CEO or his/her designate involved in the procurement of the good or service and the Manager of Purchasing.

(c) Upon receiving the dispute claim, a bid debriefing will take place with the Manager of Purchasing, the Purchasing staff member assigned to that procurement file and the BPI staff member involved in the procurement process and up to 2 representatives of the vendor. The Manager of Purchasing shall convene the meeting between the parties within fourteen (14) days of the receipt of the dispute claim. The debriefing session will be structured so as to provide assistance to the vendor to both understand the procurement process that occurred and to assist them in improving their future bids to BPI.

(d) Should the debriefing session fail to satisfy the vendor, the vendor may request a further meeting with the BPI CEO or his/her designate and the Manager of Purchasing. This request must be addressed to the Manager of Purchasing and received in writing within fourteen (14) days of the meeting described in section b). The Manager of Purchasing shall convene the meeting between the parties.

(e) In the event a resolution cannot be achieved and the vendor requests to further prosecute the dispute claim, the Manager of Purchasing shall request the vendor to pursue the matter through the Solicitor. The dispute claim shall then be handled by the Solicitor or his/her designate.

# CHAPTER 3
# METHODS THROUGH WHICH GOODS AND SERVICES MAY BE ACQUIRED

## 3.01 Summary of Methods

Goods and services shall be acquired by BPI in accordance with the methods set forth in the following Table One, and not otherwise.

**Table One**
**METHODS THROUGH WHICH GOODS AND SERVICES MAY BE ACQUIRED**

| **Estimated Value of Goods and Services Not including Taxes** | **Low**<br><br><$5,000 | **Medium**<br><br>$5,000 and over but < $250,000 | **High**<br><br>$250,000 and over |
|---|---|---|---|
| **Permitted Method(s) of Acquisition**<br><br>**Note: Minimum Standards Only**<br><br>(See Section 3.02. More formal methods associated with high value acquisitions may still be used for lower ranked acquisitions) | **Informal Procurement**<br><br>May use any acquisition process<br><br>Competition not required. | **Level One. Less than $25,000**<br><br>Must be at least three written quotations unless there are insufficient vendors. Public advertising **is not** required.<br><br>**Level Two. $25,000 and over**<br><br>Must be at least three written quotations unless there are insufficient vendors. Public advertising **is** required.<br><br>**Non-competitive acquisition**<br><br>Only where specifically allowed pursuant to Chapter 4 of purchasing policy. Purchasing Officer to enforce compliance with policy and determine whether or not conditions for non-competitive acquisition have been met. | **Requests for Proposals**<br><br>**Requests for Tenders**<br><br>**Non-competitive acquisition**<br><br>where specifically allowed pursuant to Chapter 4 of purchasing policy. Purchasing Officer to enforce compliance with policy and determine whether or not conditions for non-competitive acquisition have been met |
| **Who will administer the acquisition process?**<br><br>(Note: other provisions such as Section 3.08 may apply) | Department Staff<br><br>Purchasing Division staff may assist if required | **Level One. Less than $25,000**<br>Department Staff, but Purchasing Division staff may assist as required.<br><br>**Level Two. $25,000 and over**<br>Purchasing Division Staff<br><br>**Request for Proposals Level One and Two**<br>Purchasing Division Staff | Only<br>Purchasing Division Staff |
| **What other conditions must be satisfied?**<br><br>(Note: other conditions or processes may apply, Section 2.02, Section 2.03, Section 3.07 etc.) | May be awarded by department staff with appropriate signing authority if within approved budget. | May be awarded by department staff (in consultation with Purchasing Division Staff) with appropriate signing authority if within approved budget. | Awarded by Board of Directors ;<br><br>or,<br><br>May be awarded by department staff (in consultation with Purchasing Division Staff) with the appropriate signing authority if it is within the approved budget and the acquisition is a "Pre-approved Solicitation" |
| | | | |

3.02 Interpretation

The permitted methods of acquisition defined in Table One are minimum standards. Although Table One indicates that the allowed methods of acquisition shall become progressively more formal as the estimated value of goods and services increases, department staff may choose to use more formal methods of acquisition than are specified as minimum standards in the table. For instance, department staff may choose to use Requests for Proposals or Requests for Tenders for medium value acquisitions, despite the fact that Table One would authorize the same acquisition to occur through a Request for Quotations.

3.03 Inflation Adjustment to Figures and Limits

The dollar limits contained in Table One shall be adjusted as part of the review of this Policy pursuant to Section 2.10 to take account of the effect of inflation.

3.04 Procedures

(a) The Purchasing Officer may make written procedures from time to time consistent with the requirements of this Policy to reflect best purchasing and acquisition practices. Without limiting the generality of the foregoing, such procedures shall include rules for issuance of solicitations, receipt of submissions, the creation and drafting of specifications for solicitations, advertising, deposit requirements, prequalification processes, breaking ties between identical submissions, calculating the Estimated Value of Goods and Services, minimum standards for performance security, and the opening procedures for solicitations.

(b) Procedures enacted pursuant to (a) shall have been approved by the Senior Leadership Team of BPI.

(c) Where the Purchasing Officer has developed procedures in accordance with (a) above, operating departments shall follow such procedures.

3.05 Special Provisions for Emergencies

(a) When emergency conditions occur, the provisions of Table One shall be read in conjunction with this section and section 4.02(f).

(b) Despite the requirement that Board of Directors approval shall first be obtained in certain situations set forth in Table One, it shall not be necessary to obtain Board of Directors approval where the acquisition of goods and services is required to meet an emergency.

(c) Except for the adjustments made in accordance with (a) and Article 4.02(f), all other terms and requirements of this Policy shall continue to apply to the acquisition of goods and services in an emergency.

(d) Whenever the provisions of this section or section 4.02(f) are applied in an emergency situation, a report to the Board of Directors Board of Directors shall be made by the BPI CEO or BPI Director as soon as practicable thereafter detailing the circumstances of the emergency, the details of the goods and services acquired in order to meet the emergency, and all other pertinent details.

3.06 Division of Procurement to Avoid Compliance with Policy

The procurement of goods and services shall not be separated or divided into multiple procurements where the purpose of such separation or division is to take advantage of the reduced formality in the acquisition of goods and service where the acquisition occurs at a lower estimated cost. Related procurements shall be combined wherever possible with a view to obtaining the lowest overall cost to the ratepayer.

3.07 Prequalification Processes

(a) Except for the acquisition of consulting services in accordance with Chapter 5, it is the policy of BPI that prequalification processes are generally discouraged in the acquisition of goods and services.

(b) Except for the acquisition of consulting services in accordance with Chapter 5 of this Policy, prequalification processes may only be used in any solicitation if the Purchasing Officer has concluded that their application is appropriate in the circumstances of the particular acquisition.

(c) In generating specifications for any prequalification process, the Purchasing Officer shall ensure that any Request for Prequalification:

(i) Includes only reasonable requirements;
(ii) does not include any unnecessary condition or restriction which would prevent an appropriate level of competition in the solicitation; and,
(iii) does not disallow the participation of bidders or proponents who are capable of performing the work.

(d) Nothing in (c) above shall prohibit the inclusion within any Request for Prequalification of a requirement which only permits a fixed number of candidates to advance to the next phase of a solicitation process if the Purchasing Officer concludes that such a requirement is necessary and advisable in the circumstances.

3.08 Authority of Department Staff

References within Table One or within the remainder of this policy to “Department Staff” or “Operating Departments” shall not be deemed to confer upon any staff member any jurisdiction or authority which that staff member would not otherwise have and, without limiting the generality of the foregoing, nothing in this policy shall diminish or reduce any reporting relationship or the authority of management to give direction to subordinate employees.

3.09 Prohibited Classes of Vendor

(a) BPI shall not acquire goods and services from any of the following:

- (i) Municipal Councillors and members of the Board of Directors of BPI's shareholder;
- (ii) Members of the BPI Board of Directors;
- (ii) Staff of BPI at or above the level of Director; or,
- (iii) Corporations or partnerships in which the individuals in (i) or (ii) hold a "controlling interest". For purposes of the foregoing, "controlling" shall be interpreted and applied in the same manner that it is defined and applied in the Income Tax Act (Canada).

(b) In any solicitations which occur by way of Request for Expressions of Interest, Request for Quotations, Request for Tender, or Request for Proposal, information shall be solicited which shall permit BPI to determine whether the prohibition in (a) will be contravened. The Purchasing Officer shall, unless he or she has actual notice to the contrary, be entitled to rely upon any certificate or affidavit so produced.

(c) Nothing in (a) above shall prohibit the supply of the normal functions of the office or employment of BPI staff or members of the Board of Directors.

# CHAPTER 4
# NON-COMPETITIVE PROCUREMENT

4.01 General Rule

Unless permitted by a specific exception within this Policy, all acquisitions of goods and services made pursuant to this Policy shall include a competitive process.

4.02 Exceptions

In acquiring goods and services for BPI, non-competitive procurement processes may be used in the following circumstances:

(a) For low-value informal procurements as set forth in Table One;

(b) For procurements of goods and services where there is a statutory or market based monopoly; or in circumstances where in the Purchasing Officer has concluded that market conditions make it impractical to use competitive procurement processes;

(c) For procurements of goods and services where the required item is covered by an exclusive right such as a patent, copyright or exclusive licence;

(d) For procurements of goods and services when BPI is exercising an existing “option to buy” where such option to buy was obtained through a competitive process or pursuant to specific Board of Directors approval;

(e) For procurements of goods and services when in the opinion of the Purchasing Officer it is important to acquire compatible goods or services and compatible goods or services are only available from a particular vendor;

(f) For procurements of goods and services when the acquisition of the goods and services are necessary to respond to an emergency and there is insufficient time to use competitive procurement processes;

(g) In any case where the Board of Directors has granted specific approval for the use of non-competitive procurement processes;

(h) In any case where the Board of Directors has approved a specific standard for goods or services, and the approval of the standard necessarily implies that non-competitive procurement processes will be used;

(i) In any case where elsewhere within this Policy the use of non-competitive procurement processes is expressly authorized.

(j) In any case involving the acquisition of unique historical artifacts;

(k) When no compliant submissions have been received in response to a competitive solicitation, and the Purchasing Officer has concluded that it would be impractical to issue a further competitive solicitation.

(l) To permit a temporary extension of no more than three (3 months) of an existing contract that has expired or is about to expire to permit the uninterrupted supply of goods and services while a new solicitation is being prepared.

# CHAPTER 5
# ACQUISITION OF CONSULTING SERVICES

5.01 Considerations in the engagement of consulting services

While price is always an important consideration in any procurement, when consultants are being engaged by BPI I, price is very often secondary to considerations of the experience and qualifications of the proposed consultant examined in light of the requirements of the particular project or engagement for which the consultant is being retained.

5.02 Use of Two-Envelope Processes

(a) When acquiring consulting services and the estimated cost is at the High Level of Value depicted in Table One, BPI shall employ the Two-Envelope Process and shall only open the envelope containing the prices of bidders if the other envelope has permitted the evaluation committee to determine that the bidder has the necessary technical and qualitative requirements to perform the consulting engagement.

(b) The evaluation committee shall be composed of the Purchasing Officer and such other individuals as may be appointed thereto by the BPI CEO or BPI Director where applicable) responsible for the project. In addition to the other members of the committee appointed by the BPI CEO or BPI Director, the BPI CEO may also place himself or herself on the committee.

(c) As an alternative to the Two-Envelope process when acquiring consulting services at the High Level of Value depicted in Table One, the Purchasing Officer may choose to engage in a preliminary prequalification process to select not less than three qualified bidders who shall be invited to make a submission in response to a formal Solicitation. In circumstances where such a choice has been made to proceed through a preliminary prequalification process, an evaluation committee composed exactly as set forth in (a) and (b) above shall be established to determine the list of qualified bidders who shall receive an invitation.

(d) Solicitations for consulting services shall include evaluation criteria consistent with section 1.01 of this Policy to be used in the selection process.

5.03 Procedures

(a) The Purchasing Officer may make written procedures from time to time consistent with the requirements of this Policy to reflect best purchasing and acquisition practices respecting the solicitation of consulting services.

(b) Procedures enacted pursuant to (a) shall have been approved by the Senior Leadership Team of BPI.

(c) Where the Purchasing Officer has developed procedures in accordance with (a) above, operating departments shall follow such procedures.

# CHAPTER 6
# SELECTION OF SUCCESSFUL VENDORS

6.01 General Rule

(a) Unless permitted by a specific exception within this policy, whenever a competitive process is used to acquire goods and services for BPI, the vendor who has made the lowest responsive submission shall be awarded the contract to supply the goods and services to BPI.

(b) The rule in (a) shall be read with necessary modifications when a solicitation includes a revenue component. In such circumstances, the vendor who has made the responsive submission, which has the best financial impact on BPI, shall be awarded the contract to supply the goods and services to BPI.

(c) When possible, solicitations should include specific reference to those components of the definition of lowest overall cost, which pertain to the competition and shall be used in the analysis of submissions.

6.02 Exceptions

In acquiring goods and services for BPI, the general rule in section 6.01 shall not apply in the following circumstances:

(a) When there has been a documented failure of the Vendor to provide appropriate performance in past procurements with BPI; and the Purchasing Officer gave notice to the Vendor at the time of the non-performance that the Vendor's default would be taken into account in future competitions involving the Vendor;

(b) When factors other than price are specifically solicited by BPI, and after taking these other factors into account, BPI has determined that the contract to supply the goods and services should not be awarded to the lowest responsive bidder;

(c) When considering proposals submitted in response to a request for proposals;

(d) When there are litigious circumstances as set forth in Section 6.04; and,

(e) In solicitations for consulting services as set forth in Chapter 5.

6.03 Procedures

(a) The Purchasing Officer shall make written procedures from time to time consistent with the requirements of this Policy to reflect best practices for the documentation of past failures of Vendors to provide appropriate performance in past procurements.

(b) Procedures enacted pursuant to (a) shall have been approved by the Senior Leadership Team of BPI.

(c) Where the Purchasing Officer has developed procedures in accordance with (a), operating departments shall follow such procedures and shall cooperate with the Purchasing Officer in the documentation of such past failures.

6.04 Litigation with potential Vendors

(a) It is a matter of great importance to BPI in the administration of contracts that BPI's relationship with vendors should be as productive, amicable, and harmonious as is reasonably possible.

(b) When a potential vendor has responded to a solicitation from BPI for the supply of goods and services to BPI, and the potential vendor is:

  (i) threatening litigation or pursuing litigation against BPI in relation to previous contracts awarded to that bidder by BPI; or,

  (ii) a person against whom BPI is pursuing litigation,

  BPI shall be entitled to reject the submission of the Vendor, despite the fact that its submission might otherwise have met the conditions, which would have made it successful.

(c) All solicitations prepared by or on behalf of BPI shall implement and reflect the requirements of this section.

# CHAPTER 7
# PROCUREMENTS WHICH MUST BE AWARDED BY THE BOARD OF DIRECTORS

7.01 General

The rules for determining whether or not it is the Board of Directors or staff that must award particular procurements and contracts are generally contained within Table One, as interpreted in conjunction with the definition of the term "pre-approved solicitation" in Section 1.05.

7.02 Contracts which must be awarded by the Board of Directors

Despite the contents of Table One or any other requirement of this Policy, the following contracts shall be awarded by the Board of Directors and not BPI Staff:

(a) Contracts for the supply of goods and services which have a term of one year and a day, or greater, provided that the foregoing shall not apply to:

(i) a contract which includes a non-binding option under which BPI may obtain not more than four successive one-year extensions of the term;

(ii) a contract for which funding is to be paid from an account or accounts which have been approved as part of a multi-year budget, and the contract is within the limits of such multi-year budget, as approved;

(iii) a contract awarded following a solicitation for which the Board of Directors has made a specific exception pursuant to this subsection; or

(iv) a contract under which the total amount to be paid over the full term of the contract will not exceed Twenty-Five thousand dollars ($25,000.00).

(b) Contracts awarded pursuant to Section 3.05(b); and,

(c) Such other specific contracts as the Board of Directors may from time to time specify by Resolution, provided that the addition on a general or continuing basis of any class or variety of contract which shall thereafter be awarded by the Board of Directors must be approved through a resolution which amends this Policy.

7.03 Information to be obtained

In any solicitations which occur by way of Request for Expressions of Interest, Request for Quotations, Request for Tender, or Request for Proposal, a certificate or affidavit shall be solicited verifying whether or not any of the items in Section 7.02 apply. The Purchasing Officer shall, unless he or she has actual notice to the contrary, be entitled to rely upon any certificate or affidavit so produced.

# CHAPTER 8
# UNFORSEEN AND CONTINGENT EVENTS

8.01 Introduction

(a) The acquisition of goods and services is sometimes complicated by the happening of events and circumstances which are either entirely unforeseen or are foreseen with greater or lesser degrees of probability.

(b) The purpose of this Chapter is to make provision for the treatment of some of the more common examples of the foregoing. It is not intended to provide an exhaustive description of all possibilities.

8.02 Insufficient Budget at time of award of solicitation

In the event that all submissions received in response to a solicitation exceed the funds available for the completion of the project, BPI may pursue the following options:

(a) BPI may add funds to those already allocated to the project so that there are sufficient funds to enable BPI to select a submission;

(b) All submissions may be rejected and BPI may cancel the solicitation and abandon the procurement of the good or service;

(c) All submissions may be rejected and BPI may engage in a further solicitation, either with or without amendments from the preceding solicitation. Before proceeding to engage in a further solicitation which does not include any significant amendment from the preceding solicitation, the Purchasing Officer shall consider whether any unfair advantage will be obtained by any person by so proceeding, and the Purchasing Officer shall consult with the Solicitor with respect to same; or,

(d) If the lowest submission is within 15% of the available funds (excluding HST), BPI may negotiate with the Vendor who submitted the lowest responsive submission in an attempt to achieve the acquisition of the goods and services at a price which fits within the available funds. BPI may proceed to the Vendor who submitted the next lowest responsive submission in the event that negotiations are unsuccessful, and so on until BPI is able to negotiate a price or BPI chooses to abandon the process and reject all submissions. For purposes of the foregoing, negotiation may include minor adjustments in the specifications of the goods and services to be acquired, and the minor adjustment of other obligations of the parties.

8.03 Additional costs encountered during completion of contract or project

(a) Whenever any purchase of goods or services has been authorized pursuant to this Policy, the responsible operating department may authorize the disbursement of additional funds to complete the purchase of goods and services where unexpected contingencies have arisen for which no or insufficient provision has been made, provided that:

(i) When dealing with medium value and low value acquisitions, such additional funds shall not exceed the lesser of 15% of the original contract, or $15,000;

or,

When dealing with high value acquisitions, such additional funds shall not exceed the lesser of 10% of the original contract, or $100,000; and,

(ii) the additional funds are required in order to complete the work set out in the original contract; and,

(iii) there are sufficient funds in the applicable department budget to pay the additional funds.

(b) Where the original contract for the acquisition of goods and services was approved by Board of Directors, a further approval of the amounts permitted to be disbursed pursuant to (a) above shall not be required unless a contrary intention was expressed in the original Board of Directors approval.

(c) If the rules in (a) and (b) are insufficient to provide the additional funds required to complete the work set out in the original contract, a further approval shall be required in respect of the funds, obtained as follows:

(i) If the contract was originally approved by Board of Directors, the additional funds required to complete the work shall be requested from Board of Directors; or,

(ii) If the contract was originally approved by Staff, the additional funds required to complete the work shall be requested from the BPI CEO. .

8.04 Application of amounts set aside as a contingency

(a) Staff are encouraged to make reasonable provision for probable contingencies in the development of the Estimated Value of Goods and Services, the specifications, and the contract documents for the acquisition of goods and services for BPI.

(b) In the event that a contract or solicitation makes explicit provision or allowance for the happening of any contingency, the application of such provision or the expenditure of any related allowance shall be a normal part of the administration of the contract for all purposes of this Policy.

# CHAPTER 9
# INTEGRITY

## 9.01 Integrity

Without limiting the application of the confidentiality provisions of the Municipal Freedom of Information and Protection of Privacy Act or the requirements of policies governing staff conduct which the Board of Directors may from time to time establish, no employee shall share confidential information with any potential Vendor which would cause that potential Vendor to gain an unfair advantage or to suffer any disadvantage in a competitive process for the supply of goods and services to BPI.

# CHAPTER 10
# ERRORS IN SUBMISSIONS

10.01 Recognition of Issue

BPI recognizes that submissions presented in response to solicitations of BPI may from time to time contain errors, not all of which shall be fatal to the consideration of the submission. The purpose of this Chapter is to define the consequences of certain common errors in submissions which may be received by BPI.

10.02 Consequences of specific varieties of error

The following Table Two is a list of some errors or irregularities in the submission of a solicitation to BPI and the consequences associated with each such error or irregularity. Errors or irregularities which are capable of being corrected and have been corrected in accordance with Table Two shall not prevent a submission from being classified as "Responsive" for purposes of this policy. Table Two is not intended to provide an exhaustive description of all possibilities.

**Table Two**
**ERRORS AND IRREGULARITIES IN SUBMISSIONS AND CONSEQUENCES OF EACH ERROR OR IRREGULARITY**

| ERROR OR IRREGULARITY | CONSEQUENCE |
|---|---|
| Late submission. | Automatic rejection. |
| Bid security, assurance to bond or other required performance security not contained within Submission. | Automatic rejection. |
| Bid security, assurance to bond or other required performance security not in required amount or form. | Automatic rejection. |
| Bid security, assurance to bond or other required performance security is either unenforceable, or is not fully enforceable on its face. Includes the situation where a bid bond or agreement to bond is issued by a surety company which is not licensed in Ontario. | Automatic rejection. |
| Submission not written in ink or other non-erasable medium. | Automatic rejection. |
| Submission, bid security or assurance to bond is not originally signed but is a completed photocopy - i.e. Submission has only a photocopy of the Vendor's signature, not the original. | May provide original signed document within two business days of notification by BPI, but no change in Submission permitted. |
| Submission is qualified – i.e. contains a restriction or qualification where such restrictions or qualifications are not permitted by the Solicitation. | Automatic rejection. |

| | |
|---|---|
| All required items not included in Submission, including but not limited to:<br>• missing signature on the Form of Tender/Proposal/ Quotation;<br>• missing Form of Tender/Proposal/Quotation pages or schedules;<br>• missing form or other document where the Solicitation requires that information to be a mandatory requirement within the Submission. | Automatic rejection. |
| An unauthorized amendment to the Solicitation's Form of Tender/Proposal/Quotation - i.e. Form of Tender is not the exact reproduction of the form provided in the Solicitation or includes alterations not provided for in the Solicitation. | Automatic rejection. |
| Any addenda to Solicitation not acknowledged. | May provide acknowledgement within two business days of BPI's notification of the error, but no change in Submission is permitted. |
| Submission contains obvious clerical or mathematical errors. | May correct error within two business days of BPI's notification of the error, but no change in unit price or lump sum price in Submission is permitted. |
| Item shown as a "total" or sum inconsistent with figures added. | May correct error within two business days of BPI's notification of the error, but no change in unit price or lump sum price in Submission is permitted. |
| Alterations have been made to the Submission but have not been initialed to verify authenticity. | May correct error within two business days of BPI's notification of the error, but no change in the Submission is permitted. |
| Mistake in Submission not obvious on the face of the Submission. | No relief. |
| Failure to attend mandatory site meeting at the time specified in the Solicitation or failure to sign in as required in the Solicitation. | Automatic rejection. |

# CHAPTER 11
# ENFORCEMENT

11.01 Role of Purchasing Officer

(a) The Purchasing Officer shall enforce compliance with this Policy.

(b) In enforcing compliance with this Policy, the Purchasing Officer may report transgressions of this Policy directly to the Board of Directors, CEO or such other management staff of BPI who may seem appropriate to him or her in the circumstances.

(c) It is the intention that in reporting transgressions pursuant to (b) above, the Purchasing Officer shall generally report to the next highest level in the management chain above the person who has committed the transgression, but the Purchasing Officer may report directly to a higher level if the consequences of the transgression appear especially significant to him or her.

(d) If reporting transgressions to the BPI CEO or to the Board of Directors pursuant to the foregoing, the Purchasing Officer shall liaise with and seek direction from the Solicitor prior to so doing.

11.02 Independence of Purchasing Officer

(a) In fulfilling his or her role in enforcing compliance with this Policy and subject to section 11.01(d) above, the Purchasing Officer shall be independent of management structure and any inappropriate administrative or political influences.

(b) The Purchasing Officer shall otherwise be subject to usual management and administrative control and direction, including administrative control and direction regarding his or her administrative roles and responsibilities (such as the development of procedures) pursuant to this Policy.

11.03 Review Rights

For purposes of enforcement of this Policy, the Purchasing Officer shall have the right to examine any document or file in the possession of any operating department which pertains to the acquisition of goods or services by that department.

11.04 Training

As a proactive means of enforcing compliance with this Policy, the Purchasing Officer shall conduct training as required to teach the requirements of this Policy to the staff of BPI.

11.05 Discipline

Breaches of this Policy by employees may be subject to disciplinary action in accordance with principles and practices enforced by the Human Resources Department.

11.06 Accountability

Staff are accountable for the decisions and actions which they take pursuant to this Policy and in the administration of contracts which have been awarded pursuant to this policy.

# SCHEDULE 1
# EXEMPTIONS

In acquiring the following goods and services, operating departments shall not be required to follow the procedures and methods described in this Policy:

1. Transaction-specific exceptions approved by the Board of Directors

   Transaction-specific exceptions approved by the Board of Directors from time to time through resolution, it being the intention that any new exceptions of general or continuing application will be approved by resolution as additions to this Schedule.

2. Training and Education

   (a) Conferences, conventions, workshops, courses and seminars
   (b) Magazines, subscriptions, books and periodicals,
   (c) Memberships
   (d) Staff development

3. Refundable Employee Expenses

   (a) Advances
   (b) Meal Allowances
   (c) Travel and Entertainment

4. Employer's General Expenses

   (a) Reimbursed Employee expenses
   (b) Payroll and honoraria remittances
   (c) Medical exams,
   (d) Government licence fees
   (e) Grants and levies payable to outside agencies
   (f) Grants pursuant to community improvement plans and other similar initiatives
   (g) Damage and insurance deductible claims
   (h) Petty cash replenishment
   (i) Tax remittances
   (j) Refunds/overpayments of taxes/fees
   (k) Payments pursuant to agreements approved by the Board of Directors
   (l) Realty taxes
   (m) Payment for employment
   (n) Bank charges and services payable to the Board-approved banker
   (o) Commodity Price Hedging Agreements if done in accordance with BPI policy affecting such agreements.
   (p) Debenture Payments;
   (q) Purchases of Investments where done pursuant to the approved investment and Financial Policies of BPI.
   (r) Temporary staffing agencies and services

5. Professional and Special Services

   (a) Special tax, accounting and audit services and advice from the Shareholder - approved auditor.
   (b) Outside Legal Services
   (c) Witness fees
   (d) Board honoraria
   (e) Real Estate Appraisals
   (f) Arbitration Fees
   (g) Counseling fees
   (h) Advertising
   (i) Entertainers for theatre or special events
   (j) Medical fees

6. Utilities

   (a) Water
   (b) Sewer
   (c) Natural Gas
   (d) Electricity
   (e) Postage
   (f) Television charges

7. Real Property Interests

   (a) All real estate transactions

# DEPRECIATION, AMORTIZATION AND DEPLETION

Amortization on capital assets is calculated as follows:

- BPI uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year plus 50% of the current year capital additions.

- BPI's amortization policy has been to take a full year's amortization on capital additions during the current year. Per Board guidelines, BPI used the half-year rule when accounting for amortization expense in the 2008 Board Approved Cost-of-Service Rate Application. BPI has not applied the half-year rule for financial reporting purposes; however it was applied again for rate-making purposes in the current Application. Depreciation rates are in line with rates set out in the Asset Depreciation Study completed by Kinectrics Inc. These rates are reflected in the tables that follow.

- BPI does not have any Asset Retirement Obligations to identify.

- Below is BPI's Amortization Policy. The full Capitalization Policy can be found in Exhibit 2, Tab 3, Schedule 3. There are no changes between this Depreciation/Amortization policy and the policy that was filed in the 2008 Cost-of-Service Rate Application.

**Depreciation and Amortization**

There are a number of factors that BPI must consider to comply with its obligation to depreciate and amortize certain capital assets. Among the most significant which forms part of the Capital assets Policy are the following:

- For general purpose financial statement reporting, BPI is required to perform a review of depreciation/amortization methods and useful lives at least at each financial year end.
- As many of the assets have long service lives, changes to useful lives would typically be

implemented in tandem with Cost-of-Service Rate Applications to maintain harmonization between capital asset values for regulatory and general purposes. Nevertheless, where there is clear evidence that useful lives selected are inappropriate; BPI will consider proceeding with such a change.

- The residual value will also be reviewed at least every financial year-end to ensure the depreciation of an asset ceases when the carrying amount of the asset is equal to the residual value for that asset. The residual value of an asset is the estimated amount that BPI would currently obtain from disposal of the asset, after deducting the estimated costs of disposal, if the asset were already of the age and in the condition expected at the end of its useful life.
- Significant parts or components of an asset that are significant in relation to the total cost of an asset will be depreciated separately when the component's useful life differs from the primary asset.
- In line with the discussion above related to Grouped or like assets, the vintage basis of depreciation is the system of categorizing like assets together for depreciation purposes using a depreciation method that will allocate the combined cost of the assets over their estimated useful life in a rational and systematic manner. BPI will use this approach in depreciating or amortizing like or grouped capital assets.
- While depreciation and amortization expense is typically included in net income, there are situations where it may be included in the carrying amount of another asset. In these situations, the future economic benefits embodied in an asset are absorbed in producing other assets. In this case, the depreciation charge constitutes part of the cost of the other asset and is included in its carrying amount. For example, BPI includes in the cost of a self-constructed asset, amounts related to depreciation of vehicles used in the construction of that asset.
- Depreciation or amortization of an asset begins when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management. Depreciation or amortization of an asset ceases at the earlier of

the date that the asset is classified as held for sale and the date that the asset is derecognized. Therefore, depreciation does not cease when the asset becomes idle or is retired from active use unless the asset is fully depreciated.

The future economic benefits embodied in an asset are consumed by BPI principally through its use. However, other factors, such as technical or commercial obsolescence and wear and tear while an asset remains idle, often result in the diminution of the economic benefits that might have been obtained from the asset. Consequently, all the following factors are to be considered in determining the useful life of an asset:

- Expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output;

  Expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance program, and the care and maintenance of the asset while idle;

- Technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset;

- Legal or similar limits on the use of the asset e.g. expiry dates of licenses or leases. The useful life of an asset is defined in terms of the asset's expected utility to BPI. The asset management policy of BPI factors various attributes in determining the expected disposal time incorporating condition assessment and probability of failure. Therefore, the useful life of an asset may be shorter than its economic or physical life. The estimation of the useful life of the asset is a matter of judgment based on the experience of BPI with similar assets in similar installations.

1 **Table 4.35 – Summary of Amortization Expense for 2008 to 2013**

| Account | Description | 2008 Amortization Expense | 2009 Amortization Expense | 2010 Amortization Expense | 2011 Amortization Expense | 2012 Amortization Expense | 2013 Amortization Expense |
|---|---|---|---|---|---|---|---|
| 1611 | Computer Software (Formally known as Account 1925) | | | $ - | $ - | $ (122,545.00) | $ (121,073.62) |
| 1612 | Land Rights (Formally known as Account 1906) | | | $ - | $ - | $ (7,262.00) | $ (1,294.00) |
| 1805 | Land | $ - | $ - | $ - | $ - | $ - | $ - |
| 1806 | Land Rights | $ - | $ - | $ - | $ - | $ - | $ - |
| 1808 | Buildings | $ (23,274.00) | $ (23,274.00) | $ (23,274.00) | $ (23,274.00) | $ (23,274.00) | $ (27,086.00) |
| 1810 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - |
| 1815 | Transformer Station Equipment >50 kV | $ (111,739.00) | $ (111,739.00) | $ (111,739.00) | $ (112,708.27) | $ (112,698.00) | $ (104,104.00) |
| 1820 | Distribution Station Equipment <50 kV | $ (2,480.00) | $ (2,481.00) | $ (2,481.00) | $ (2,481.00) | $ (2,481.00) | $ (1,560.00) |
| 1825 | Storage Battery Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1830 | Poles, Towers & Fixtures | $ (547,481.35) | $ (580,646.62) | $ (611,734.45) | $ (638,939.43) | $ (663,581.00) | $ (374,253.00) |
| 1835 | Overhead Conductors & Devices | $ (418,480.58) | $ (437,209.76) | $ (458,439.22) | $ (484,656.47) | $ (522,660.00) | $ (243,122.00) |
| 1840 | Underground Conduit | $ (450,828.33) | $ (478,072.09) | $ (503,959.36) | $ (531,436.63) | $ (552,655.00) | $ (233,392.00) |
| 1845 | Underground Conductors & Devices | $ (534,022.34) | $ (609,144.94) | $ (623,972.35) | $ (696,655.10) | $ (772,213.00) | $ (640,974.00) |
| 1850 | Line Transformers | $ (595,764.04) | $ (634,683.60) | $ (654,597.81) | $ (681,294.85) | $ (713,874.00) | $ (447,040.00) |
| 1855 | Services (Overhead & Underground) | $ (36,873.69) | $ (41,313.89) | $ (31,495.02) | $ (50,765.74) | $ (55,543.00) | $ (56,061.00) |
| 1860 | Meters | $ (288,812.20) | $ (241,580.88) | $ (349,468.92) | $ (629,086.32) | $ (378,890.00) | $ (783,165.38) |
| 1860 | Meters (Smart Meters) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1905 | Land | $ - | $ - | $ - | $ - | $ - | $ - |
| 1908 | Buildings & Fixtures | $ - | $ - | $ - | $ - | $ - | $ - |
| 1910 | Leasehold Improvements | $ - | $ - | $ - | $ - | $ - | $ - |
| 1915 | Office Furniture & Equipment (10 years) | $ - | $ - | $ - | $ - | $ (500.00) | $ (500.00) |
| 1915 | Office Furniture & Equipment (5 years) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920 | Computer Equipment - Hardware | $ - | $ - | $ - | $ - | $ (200.00) | $ (18,325.73) |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1925 | Computer Software | $ (33,566.27) | $ (39,270.10) | $ (39,277.69) | $ (87,063.91) | $ - | $ - |
| 1930 | Transportation Equipment | $ (246,533.12) | $ (275,556.84) | $ (266,239.72) | $ (271,416.00) | $ (203,065.00) | $ (161,947.00) |
| 1935 | Stores Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1940 | Tools, Shop & Garage Equipment | $ (14,272.07) | $ (17,858.89) | $ (18,421.51) | $ (14,030.00) | $ (14,030.00) | $ (17,781.00) |
| 1945 | Measurement & Testing Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1950 | Power Operated Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1955 | Communications Equipment | $ (236.06) | $ (236.06) | $ (232.88) | $ - | $ - | $ - |
| 1955 | Communication Equipment (Smart Meters) | $ - | $ - | $ - | $ - | $ - | $ - |
| 1960 | Miscellaneous Equipment | $ - | $ - | $ - | $ - | $ - | $ - |
| 1970 | Load Management Controls - Customer Premises | $ (54,797.00) | $ (54,797.00) | $ (45,667.00) | $ - | $ - | $ - |
| 1975 | Load Management Controls Utility Premises | $ - | $ - | $ - | $ - | $ - | $ - |
| 1980 | System Supervisor Equipment | $ (23,107.09) | $ (29,731.25) | $ (43,509.44) | $ (43,981.54) | $ (48,869.00) | $ (31,605.00) |
| 1985 | Miscellaneous Fixed Assets | $ - | $ - | $ - | $ - | $ - | $ - |
| 1995 | Contributions & Grants | $ 105,762.30 | $ 135,583.65 | $ 143,428.65 | $ 154,073.28 | $ 154,072.28 | $ 105,753.00 |
| 2040 | Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - |
| 2055 | Work in Progress | $ - | $ - | $ - | $ - | $ - | $ - |
| | **Total** | $ (3,276,504.84) | $ (3,442,012.27) | $ (3,641,080.72) | $ (4,113,715.98) | $ (4,040,267.72) | $ (3,157,530.74) |
| | **Sub-Total Amortization Expense** | | | | | | |
| | Less: Fully Allocated Depreciation | | | | | | |
| | Transportation Equipment | $ 246,533.00 | $ 275,557.00 | $ 266,240.00 | $ 271,416.00 | $ 203,065.00 | $ 161,947.00 |
| | Stores Equipment | | | | | | |
| **NET DEPRECIATION** | | $ (3,029,971.84) | $ (3,166,455.27) | $ (3,374,840.72) | $ (3,842,299.98) | $ (3,837,202.72) | $ (2,995,583.74) |

The year-over-year fluctuations in amortization expense (as seen above) are natural based on capital additions, disposal of assets, and assets becoming fully depreciated. The $841,619 decrease for 2013 over 2012 is mainly due to longer useful lives due to the change in componentization discussed in the Asset Depreciation Study. BPI has adopted TUL estimates that were used in the Asset Depreciation Study with a few exceptions. A complete explanation can be found in Exhibit 2, Tab 3, Schedule 5. As BPI is remaining with CGAAP and reporting the 2013 Test Year in Modified CGAAP, BPI did not complete Appendix 2-CI. A description of BPI's accounting treatment and reasoning for reporting in Modified CGAAP can be found in Exhibit 1, Tab 2, Schedule 1.

BPI has provided detailed amortization expense calculations using the Board's methodology and provided a reconciliation to BPI's Audited Financial Statement amortization amounts (where applicable) in Appendices 2-CE, 2-CF, 2-CG and 2CH.

# Table 4.36 – Amortization Expense for 2011

| Account | Description | Opening Regulatory Gross PP&E as at Jan 1, 2011 (a) | Less Fully Depreciated (b) | Net for Depreciation (c) | Additions (d) | Total for Depreciation (e) = (c) + ½ x (d) [1] | Years (f) | Depreciation Rate (g) = 1 / (f) | 2011 Depreciation Expense (h) = (e) / (f) | 2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l) | Variance [2] (m) = (h) - (l) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1611 | Computer Software (Formally known as Account 1925) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1612 | Land Rights (Formally known as Account 1906) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1805 | Land | $ 181,960.63 | | $ 181,960.63 | $ - | $ 181,960.63 | | | $ - | $ - | $ - |
| 1806 | Land Rights | $ 5,968.42 | | | $ - | | | | | $ - | |
| 1808 | Buildings | $ 1,163,731.71 | | $ 1,163,731.71 | $ - | $ 1,163,731.71 | 50.00 | 2.00% | $ 23,274.63 | $ 23,274.00 | $ 0.63 |
| 1810 | Leasehold Improvements | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1815 | Transformer Station Equipment >50 kV | $ 4,469,541.30 | | $ 4,469,541.30 | $ 38,370.27 | $ 4,488,726.44 | 40.00 | 2.50% | $ 112,218.16 | $ 112,708.27 | -$ 490.11 |
| 1820 | Distribution Station Equipment <50 kV | $ 74,426.57 | | $ 74,426.57 | $ - | $ 74,426.57 | 30.00 | 3.33% | $ 2,480.89 | $ 2,481.00 | -$ 0.11 |
| 1825 | Storage Battery Equipment | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1830 | Poles, Towers & Fixtures | $ 15,293,731.41 | | $ 15,293,731.41 | $ 680,278.43 | $ 15,633,870.63 | 25.00 | 4.00% | $ 625,354.83 | $ 638,939.43 | -$ 13,584.61 |
| 1835 | Overhead Conductors & Devices | $ 11,460,981.29 | | $ 11,460,981.29 | $ 655,233.47 | $ 11,788,598.03 | 25.00 | 4.00% | $ 471,543.92 | $ 484,656.47 | -$ 13,112.55 |
| 1840 | Underground Conduit | $ 12,599,180.64 | | $ 12,599,180.64 | $ 686,868.63 | $ 12,942,614.96 | 25.00 | 4.00% | $ 517,704.60 | $ 531,436.63 | -$ 13,732.03 |
| 1845 | Underground Conductors & Devices | $ 16,270,666.20 | | $ 16,270,666.20 | $ 1,145,510.10 | $ 16,843,421.25 | 25.00 | 4.00% | $ 673,736.85 | $ 696,655.10 | -$ 22,918.25 |
| 1850 | Line Transformers | $ 16,554,086.34 | | $ 16,554,086.34 | $ 478,371.85 | $ 16,793,272.27 | 25.00 | 4.00% | $ 671,730.89 | $ 681,294.85 | -$ 9,563.96 |
| 1855 | Services (Overhead & Underground) | $ 1,077,422.88 | | $ 1,077,422.88 | $ 191,940.74 | $ 1,173,393.25 | 25.00 | 4.00% | $ 46,935.73 | $ 50,765.74 | -$ 3,830.01 |
| 1860 | Meters | $ 8,733,121.28 | | $ 8,733,121.28 | $ 411,891.78 | $ 8,939,067.17 | 25.00 | 4.00% | $ 357,562.69 | $ 629,086.32 | -$ 271,523.63 |
| 1860 | Meters (Smart Meters) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1905 | Land | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1908 | Buildings & Fixtures | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1910 | Leasehold Improvements | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1915 | Office Furniture & Equipment (10 years) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1915 | Office Furniture & Equipment (5 years) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1920 | Computer Equipment - Hardware | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1925 | Computer Software | $ 196,386.06 | | $ 196,386.06 | $ 238,942.91 | $ 315,857.52 | 5.00 | 20.00% | $ 63,171.50 | $ 87,063.91 | -$ 23,892.41 |
| 1930 | Transportation Equipment | $ 2,723,343.94 | $ 705,917.00 | $ 2,017,426.94 | $ 309,767.00 | $ 2,172,310.44 | 8.00 | 12.50% | $ 271,538.81 | $ 271,416.00 | $ 122.80 |
| 1935 | Stores Equipment | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1940 | Tools, Shop & Garage Equipment | $ 193,313.02 | $ 54,401.00 | $ 138,912.02 | $ 1,380.00 | $ 139,602.02 | 10.00 | 10.00% | $ 13,960.20 | $ 14,030.00 | -$ 69.80 |
| 1945 | Measurement & Testing Equipment | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1950 | Power Operated Equipment | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1955 | Communications Equipment | $ 1,176.32 | $ 1,176.32 | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1955 | Communication Equipment (Smart Meters) | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1960 | Miscellaneous Equipment | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1970 | Load Management Controls - Customer Premises | $ 547,972.38 | $ 547,972.38 | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1975 | Load Management Controls Utility Premises | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1980 | System Supervisor Equipment | $ 652,617.30 | | $ 652,617.30 | $ 7,701.54 | $ 656,468.07 | 15.00 | 6.67% | $ 43,764.54 | $ 43,981.54 | -$ 217.00 |
| 1985 | Miscellaneous Fixed Assets | $ - | | $ - | $ - | $ - | | | $ - | $ - | $ - |
| 1995 | Contributions & Grants | -$ 3,586,012.84 | | -$ 3,586,012.84 | -$ 265,560.28 | -$ 3,718,792.98 | 25.00 | 4.00% | -$ 148,751.72 | -$ 154,073.28 | $ 5,321.56 |
| 2040 | Plant Held for Future Use | $ 51,815.84 | | | $ 2,940.00 | $ 1,470.00 | | | $ - | $ - | $ - |
| 2055 | Work in Progress | $ 104,107.49 | | | -$ 80,098.32 | -$ 40,049.16 | | | $ - | $ - | $ - |
| etc. | | | | $ - | $ - | $ - | | | $ - | | $ - |
| | | | | $ - | | $ - | | | $ - | | $ - |
| | **Total** | $ 88,769,538.18 | $ 1,309,466.70 | $ 87,298,179.73 | $ 4,503,538.12 | $ 89,549,948.79 | | | $ 3,746,226.51 | $ 4,113,715.98 | -$ 367,489.47 |

# Table 4.37 – Amortization Expense for 2012

| Description | Opening Regulatory Gross PP&E as at Jan 1, 2012<br>(a) | Less Fully Depreciated<br>(b) | Net for Depreciation<br>(c) | Additions<br>(d) | Total for Depreciation<br>(e) = (c) + ½ x (d) [1] | Years<br>(f) | Depreciation Rate<br>(g) = 1 / (f) | 2012 Depreciation Expense<br>(h) = (e) / (f) | 2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K<br>(l) | Variance [2]<br>(m) = (h) - (l) |
|---|---|---|---|---|---|---|---|---|---|---|
| Computer Software (Formally known as Account 1925) | $ 435,328.97 | | $ 435,328.97 | $ 180,900.00 | $ 525,778.97 | 5.00 | 20.00% | $ 105,155.79 | $ 122,545.00 | -$ 17,389.21 |
| Land Rights (Formally known as Account 1906) | $ 5,968.42 | | $ 5,968.42 | $ 64,700.00 | $ 38,318.42 | 50.00 | 2.00% | $ 766.37 | $ 7,262.00 | -$ 6,495.63 |
| Land | $ 181,960.63 | | $ 181,960.63 | $ - | $ 181,960.63 | | 0.00% | $ - | $ - | $ - |
| Land Rights | $ - | | | $ - | | | | | $ - | |
| Buildings | $ 1,163,731.71 | | $ 1,163,731.71 | $ - | $ 1,163,731.71 | 50.00 | 2.00% | $ 23,274.63 | $ 23,274.00 | $ 0.63 |
| Leasehold Improvements | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Transformer Station Equipment >50 kV | $ 4,507,911.57 | | $ 4,507,911.57 | $ - | $ 4,507,911.57 | 40.00 | 2.50% | $ 112,697.79 | $ 112,698.00 | -$ 0.21 |
| Distribution Station Equipment <50 kV | $ 74,426.57 | | $ 74,426.57 | $ - | $ 74,426.57 | 30.00 | 3.33% | $ 2,480.89 | $ 2,481.00 | -$ 0.11 |
| Storage Battery Equipment | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Poles, Towers & Fixtures | $ 15,974,009.84 | | $ 15,974,009.84 | $ 584,500.00 | $ 16,266,259.84 | 25.00 | 4.00% | $ 650,650.39 | $ 663,581.00 | -$ 12,930.61 |
| Overhead Conductors & Devices | $ 12,116,214.76 | | $ 12,116,214.76 | $ 959,300.00 | $ 12,595,864.76 | 25.00 | 4.00% | $ 503,834.59 | $ 522,660.00 | -$ 18,825.41 |
| Underground Conduit | $ 13,286,049.27 | | $ 13,286,049.27 | $ 519,300.00 | $ 13,545,699.27 | 25.00 | 4.00% | $ 541,827.97 | $ 552,655.00 | -$ 10,827.03 |
| Underground Conductors & Devices | $ 17,416,176.30 | | $ 17,416,176.30 | $ 1,876,200.00 | $ 18,354,276.30 | 25.00 | 4.00% | $ 734,171.05 | $ 772,213.00 | -$ 38,041.95 |
| Line Transformers | $ 17,032,458.19 | | $ 17,032,458.19 | $ 796,400.00 | $ 17,430,658.19 | 25.00 | 4.00% | $ 697,226.33 | $ 713,874.00 | -$ 16,647.67 |
| Services (Overhead & Underground) | $ 1,269,363.62 | | $ 1,269,363.62 | $ 135,200.00 | $ 1,336,963.62 | 25.00 | 4.00% | $ 53,478.54 | $ 55,543.00 | -$ 2,064.46 |
| Meters | $ 9,145,013.06 | | $ 9,145,013.06 | $ 274,471.00 | $ 9,282,248.56 | 25.00 | 4.00% | $ 371,289.94 | $ 378,890.00 | -$ 7,600.06 |
| Meters (Smart Meters) | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Land | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Buildings & Fixtures | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Leasehold Improvements | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Office Furniture & Equipment (10 years) | $ - | | $ - | $ 5,000.00 | $ 2,500.00 | 10.00 | 10.00% | $ 250.00 | $ 500.00 | -$ 250.00 |
| Office Furniture & Equipment (5 years) | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Computer Equipment - Hardware | $ - | | $ - | $ 1,000.00 | $ 500.00 | 4.00 | 25.00% | $ 125.00 | $ 200.00 | -$ 75.00 |
| Computer Equip.-Hardware(Post Mar. 22/04) | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Computer Equip.-Hardware(Post Mar. 19/07) | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Computer Software | $ - | | | $ - | | | | | $ - | |
| Transportation Equipment | $ 3,033,110.94 | $ 1,300,989.00 | $ 1,732,121.94 | $ 325,000.00 | $ 1,894,621.94 | 8.00 | 12.50% | $ 236,827.74 | $ 203,065.00 | $ 33,762.74 |
| Stores Equipment | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Tools, Shop & Garage Equipment | $ 140,292.16 | | $ 140,292.16 | $ 25,000.00 | $ 152,792.16 | 10.00 | 10.00% | $ 15,279.22 | $ 14,030.00 | $ 1,249.22 |
| Measurement & Testing Equipment | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Power Operated Equipment | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Communications Equipment | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Communication Equipment (Smart Meters) | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Miscellaneous Equipment | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Load Management Controls - Customer Premises | $ - | | | $ - | | | | | $ - | $ - |
| Load Management Controls Utility Premises | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| System Supervisor Equipment | $ 660,318.84 | | $ 660,318.84 | $ 83,000.00 | $ 701,818.84 | 15.00 | 6.67% | $ 46,787.92 | $ 48,869.00 | -$ 2,081.08 |
| Miscellaneous Fixed Assets | $ - | | $ - | $ - | $ - | | 0.00% | $ - | $ - | $ - |
| Contributions & Grants | -$ 3,851,573.12 | | -$ 3,851,573.12 | -$ 623,500.00 | -$ 4,163,323.12 | 25.00 | 4.00% | -$ 166,532.92 | -$ 154,072.28 | -$ 12,460.64 |
| Plant Held for Future Use | $ 54,755.84 | | | $ - | | | | | $ - | |
| Work in Progress | $ 24,009.17 | | | $ - | | | | | $ - | |
| | | | | $ - | | | | | | |
| | | | $ - | $ - | $ - | | 0.00% | $ - | | $ - |
| | | | $ - | | $ - | | 0.00% | $ - | | $ - |
| **Total** | $ 92,669,526.74 | $ 1,300,989.00 | $ 91,289,772.73 | $ 5,206,471.00 | $ 93,893,008.23 | | | $ 3,929,591.25 | $ 4,040,267.72 | -$ 110,676.47 |

## Table 4.38 – Amortization Expense for 2013

| Account | Description | Opening NBV as at Jan 1, 2013 [5] (a) | Additions (d) | Average Remaining Life of Opening NBV [4] (i) | Years (new additions only) [3] (f) | Depreciation Rate on New Additions (g) = 1 / (f) | Depreciation Expense on Opening NBV (j) = (a) / (i) | Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f) | 2013 Depreciation Expense (k) = (j) + (h) | 2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l) | Variance [2] (m) = (k) - (l) | Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f) | Less Depreciation Expense on Assets Fully Depreciated during the year (o) | 2013 Full Year Depreciation [6] (p) = (j) + (n) - (o) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1611 | Computer Software (Formally known as Account 1925) | $ 296,469.00 | $ 310,000.00 | 5.00 | 5.00 | 20.00% | $ 59,293.80 | $ 31,000.00 | $ 90,293.80 | $ 121,073.62 | -$ 30,779.82 | $ 62,000.00 | | $ 121,293.80 |
| 1612 | Land Rights (Formally known as Account 1906) | $ 63,406.42 | $ - | 50.00 | 50.00 | 2.00% | $ 1,268.13 | $ - | $ 1,268.13 | $ 1,294.00 | -$ 25.87 | $ - | | $ 1,268.13 |
| 1805 | Land | $ 181,960.63 | $ - | | - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1806 | Land Rights | $ - | $ - | | - | | | | | $ - | $ - | $ - | | |
| 1808 | Buildings | $ 969,199.81 | $ - | 36.64 | | 0.00% | $ 26,451.96 | $ - | $ 26,451.96 | $ 27,086.00 | -$ 634.04 | $ - | | $ 26,451.96 |
| 1810 | Leasehold Improvements | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1815 | Transformer Station Equipment >50 kV | $ 3,614,381.00 | $ - | 33.32 | | 0.00% | $108,474.82 | $ - | $ 108,474.82 | $ 104,104.00 | $ 4,370.82 | $ - | | $ 108,474.82 |
| 1820 | Distribution Station Equipment <50 kV | $ 44,402.06 | $ - | 9.63 | | 0.00% | $ 4,610.81 | $ - | $ 4,610.81 | $ 1,560.00 | $ 3,050.81 | $ - | | $ 4,610.81 |
| 1825 | Storage Battery Equipment | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1830 | Poles, Towers & Fixtures | $ 10,132,752.00 | $ 215,000.00 | | | 0.00% | $ - | $ - | $ - | $ 374,253.00 | -$ 374,253.00 | $ - | | $ - |
| 1835 | Overhead Conductors & Devices | $ 8,684,530.00 | $ 958,000.00 | | | 0.00% | $ - | $ - | $ - | $ 243,122.00 | -$ 243,122.00 | $ - | | $ - |
| 1840 | Underground Conduit | $ 8,479,323.00 | $ 35,000.00 | | | 0.00% | $ - | $ - | $ - | $ 233,392.00 | -$ 233,392.00 | $ - | | $ - |
| 1845 | Underground Conductors & Devices | $ 14,475,705.60 | $ 856,100.00 | | | 0.00% | $ - | $ - | $ - | $ 640,974.00 | -$ 640,974.00 | $ - | | $ - |
| 1850 | Line Transformers | $ 11,444,812.00 | $ 502,000.00 | | | 0.00% | $ - | $ - | $ - | $ 447,040.00 | -$ 447,040.00 | $ - | | $ - |
| 1855 | Services (Overhead & Underground) | $ 1,140,823.00 | $ 110,000.00 | | | 0.00% | $ - | $ - | $ - | $ 56,061.00 | -$ 56,061.00 | $ - | | $ - |
| 1860 | Meters | $ 8,086,389.33 | $ 205,000.00 | | | 0.00% | $ - | $ - | $ - | $ 783,165.38 | -$ 783,165.38 | $ - | | $ - |
| 1860 | Meters (Smart Meters) | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1905 | Land | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1908 | Buildings & Fixtures | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1910 | Leasehold Improvements | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1915 | Office Furniture & Equipment (10 years) | $ 4,500.00 | $ - | | | 0.00% | $ - | $ - | $ - | $ 500.00 | -$ 500.00 | $ - | | $ - |
| 1915 | Office Furniture & Equipment (5 years) | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equipment - Hardware | $ 42,739.00 | $ 77,500.00 | | | 0.00% | $ - | $ - | $ - | $ 18,325.73 | -$ 18,325.73 | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1925 | Computer Software | $ - | $ - | | | 0.00% | $ - | $ - | | $ - | $ - | $ - | | $ - |
| 1930 | Transportation Equipment | $ 1,012,938.00 | $ 200,000.00 | | | 0.00% | $ - | $ - | $ - | $ 161,947.00 | -$ 161,947.00 | $ - | | $ - |
| 1935 | Stores Equipment | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1940 | Tools, Shop & Garage Equipment | $ 91,987.00 | $ 25,000.00 | | | 0.00% | $ - | $ - | $ - | $ 17,781.00 | -$ 17,781.00 | $ - | | $ - |
| 1945 | Measurement & Testing Equipment | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1950 | Power Operated Equipment | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1955 | Communications Equipment | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1955 | Communication Equipment (Smart Meters) | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1960 | Miscellaneous Equipment | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1970 | Load Management Controls - Customer Premises | $ - | $ - | | | 0.00% | $ - | $ - | | $ - | $ - | $ - | | $ - |
| 1975 | Load Management Controls Utility Premises | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1980 | System Supervisor Equipment | $ 544,225.71 | $ 150,000.00 | | | 0.00% | $ - | $ - | $ - | $ 31,605.00 | -$ 31,605.00 | $ - | | $ - |
| 1985 | Miscellaneous Fixed Assets | $ - | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 1995 | Contributions & Grants | -$ 3,636,217.72 | $ 203,440.00 | | | 0.00% | $ - | $ - | $ - | -$ 105,753.00 | $ 105,753.00 | $ - | | $ - |
| 2040 | Plant Held for Future Use | -$ 0.16 | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 2055 | Work in Progress | $ 24,009.17 | $ - | | | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| etc. | | | | | | 0.00% | $ - | $ - | $ - | | $ - | $ - | | $ - |
| | | | | | | 0.00% | $ - | $ - | $ - | | $ - | $ - | | $ - |
| | **Total** | $ 65,698,334.85 | $ 3,440,160.00 | | | | $200,099.51 | $ 31,000.00 | $ 231,099.51 | $ 3,157,530.74 | -$ 2,926,431.22 | $ 62,000.00 | $ - | $ 262,099.51 |

1 2013 is reported under CGAAP but BPI is aligning componentization and useful lives with

2 MIFRS.

# Table 4.39 - Appendix 2-CH

| Account | Description | Additions (d) | Years (new additions only) (f) | Depreciation Rate on New Additions (g) = 1 / (f) | 2013 Depreciation Expense [1] (h)=2012 Full Year Depreciation + ((d)*0.5)/(f) | 2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l) | Variance [2] (m) = (h) - (l) |
|---|---|---|---|---|---|---|---|
| 1611 | Computer Software (Formally known as Account 1925) | | | 0.00% | $ 121,293.80 | | $ 121,293.80 |
| 1612 | Land Rights (Formally known as Account 1906) | | | 0.00% | $ 1,268.13 | | $ 1,268.13 |
| 1805 | Land | | | 0.00% | $ - | | $ - |
| 1808 | Buildings | | | 0.00% | $ 26,451.96 | | $ 26,451.96 |
| 1810 | Leasehold Improvements | | | 0.00% | $ - | | $ - |
| 1815 | Transformer Station Equipment >50 kV | | | 0.00% | $ 108,474.82 | | $ 108,474.82 |
| 1820 | Distribution Station Equipment <50 kV | | | 0.00% | $ 4,610.81 | | $ 4,610.81 |
| 1825 | Storage Battery Equipment | | | 0.00% | $ - | | $ - |
| 1830 | Poles, Towers & Fixtures | | | 0.00% | $ - | | $ - |
| 1835 | Overhead Conductors & Devices | | | 0.00% | $ - | | $ - |
| 1840 | Underground Conduit | | | 0.00% | $ - | | $ - |
| 1845 | Underground Conductors & Devices | | | 0.00% | $ - | | $ - |
| 1850 | Line Transformers | | | 0.00% | $ - | | $ - |
| 1855 | Services (Overhead & Underground) | | | 0.00% | $ - | | $ - |
| 1860 | Meters | | | 0.00% | $ - | | $ - |
| 1860 | Meters (Smart Meters) | | | 0.00% | $ - | | $ - |
| 1905 | Land | | | 0.00% | $ - | | $ - |
| 1908 | Buildings & Fixtures | | | 0.00% | $ - | | $ - |
| 1910 | Leasehold Improvements | | | 0.00% | $ - | | $ - |
| 1915 | Office Furniture & Equipment (10 years) | | | 0.00% | $ - | | $ - |
| 1915 | Office Furniture & Equipment (5 years) | | | 0.00% | $ - | | $ - |
| 1920 | Computer Equipment - Hardware | | | 0.00% | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | | | 0.00% | $ - | | $ - |
| 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | | | 0.00% | $ - | | $ - |
| 1930 | Transportation Equipment | | | 0.00% | $ - | | $ - |
| 1935 | Stores Equipment | | | 0.00% | $ - | | $ - |
| 1940 | Tools, Shop & Garage Equipment | | | 0.00% | $ - | | $ - |
| 1945 | Measurement & Testing Equipment | | | 0.00% | $ - | | $ - |
| 1950 | Power Operated Equipment | | | 0.00% | $ - | | $ - |
| 1955 | Communications Equipment | | | 0.00% | $ - | | $ - |
| 1955 | Communication Equipment (Smart Meters) | | | 0.00% | $ - | | $ - |
| 1960 | Miscellaneous Equipment | | | 0.00% | $ - | | $ - |
| 1975 | Load Management Controls Utility Premises | | | 0.00% | $ - | | $ - |
| 1980 | System Supervisor Equipment | | | 0.00% | $ - | | $ - |
| 1985 | Miscellaneous Fixed Assets | | | 0.00% | $ - | | $ - |
| 1995 | Contributions & Grants | | | 0.00% | $ - | | $ - |
| etc. | | | | 0.00% | $ - | | $ - |
| | | | | 0.00% | $ - | | $ - |
| | **Total** | $ - | | | $ 262,099.51 | $ - | $ 262,099.51 |
| | Depreciation expense adjustment resulting from amortization of Account 1575 | | | | $ - | | |
| | **Total Depreciation expense to be included in the test year revenue requirement** | | | | **$ 262,099.51** | | |

**Notes:**

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

**General: Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

# TAXES, PAYMENTS IN LIEU OF TAXES (PILS) AND PROPERTY TAXES

BPI is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. BPI does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. In accordance with the June 2012 filing requirements the Board's PILs model has also been completed and submitted and is consistent with the PILs included in the 2013 revenue requirement. Please refer to Appendix D for the completed PILs model.

## Integrity Checks

Pursuant to the Board's F*iling Requirements For Electricity Transmission and Distribution Applications* dated June 28, 2012 with respect to the Integrity Checks listed under section 2.7.8.2, BPI hereby provides the following confirmations:

- *Integrity Check:* The depreciation and amortization added back in the PILs model agree with the numbers disclosed in the rate base section of the Cost-of-Service Rate Applications.

  *Confirmation:* Table 4.40 shows a reconciliation between depreciation and amortization as reported in the PILs model compared to that reported in the Fixed Asset (FA) Continuity Schedules and amounts agree.

**Table 4.40 - Depreciation per Rate Base in Comparison to PILs Model**

| | 2011 CGAAP | 2012 CGAAP | 2013 MCGAAP* |
|---|---|---|---|
| Depreciation/Amortization per FA Continuity Schedules | $ 4,113,716 | $ 2,007,887 | $ 3,157,531 |
| Add: Amortization of Stranded Meters | - | $ 2,032,381 | |
| Less: Amortization of Smart Meters | | | $ (364,103) |
| Depreciation/Amortization per PILs Model | $ (4,113,716) | $ (4,040,268) | $ (2,793,428) |
| | - | - | - |
| *Modified CGAAP | | | |

- *Integrity Check:* The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base historic, bridge and test years.

*Confirmation:* Below Table 4.41 shows BPI's reconciliation between capital asset additions for Rate Base in comparison to that used for income tax purposes.

**Table 4.41 - Capital asset additions per rate Base in comparison to CCA/UCC schedules**

| | 2011 CGAAP | 2012 CGAAP | 2013 MCGAAP |
|---|---|---|---|
| Capital asset additions as per FA Continuity Schedules | $ 3,892,577 | $ 5,206,471 | $ 3,440,160 |
| Less: capitalized overheads | | $ (1,033,000) | |
| Less: land rights not deductible for tax purposes | | $ (64,700) | |
| Add: smart meter additions through deferral accounts | | $ 86,528 | |
| UCC/CCA Additions | $ (3,892,577) | $ (4,195,299) | $ (3,440,161) |
| difference = rounding | - | - | **(1.00)** |

- *Integrity Check:* Schedule 8 of the most recent federal T2 tax return filed with the Cost-of-Service Rate Applications has a closing December 31st historical year UCC that agrees with the opening bridge year UCC at January 1st. If the amounts do not agree, then the applicant must provide a reconciliation with explanations for the reasons.

*Confirmation:* Table 4.42 below shows the ending balance of CCA Schedule 8 at December 31, 2011 (Historical Year) represents the opening balance of CCA Schedule 8 at January 1, 2012 (Bridge Year) and the amounts match.

**Table 4.42 - Schedule 8 December 31st historical year UCC compared to the opening bridge year UCC at January 1st**

| | |
|---|---|
| Schedule 8 closing balance December 31, 2011 | $ 62,368,243 |
| Opening UCC balance January 1st , 2012 (Bridge Year) | $(62,368,243) |
| | - |

- *Integrity Check:* The CCA deductions in the Cost-of-Service Rate Application's PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the Cost-of-Service Rate Application.

  *Confirmation:* CCA deductions agree as shown in Table 4.43 below.

**Table 4.43 - CCA deduction in PILs model in comparison to CCA Schedules**

| | 2011 CGAAP | 2012 CGAAP | 2013 MCGAAP |
|---|---|---|---|
| CCA deduction per Schedule 8 | 4,172,471 | $ 4,250,887 | $ 4,376,304 |
| CCA deduction per PILs model | (4,172,471) | $ (4,250,887) | $ (4,376,304) |
| | - | - | - |

- *Integrity Check:* Loss carry-forwards, if any, from tax returns (Schedule 4) agrees with those disclosed in the Cost-of-Service Rate Application.

  *Confirmation:* Not applicable to BPI.

- *Integrity Check:* CCA is maximized even if there tax loss carry-forwards.

  *Confirmation:* BPI is claiming the maximum CCA and has no loss carry-forwards.

- *Integrity Check:* A statement is included in the Cost-of-Service Rate Application as to when the losses, if any, will be fully utilized.

  *Confirmation:* Not applicable to BPI.

- *Integrity Check:* Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of account income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.

*Confirmation:* Table 4.44 shows a reconciliation between employee future benefits in comparison to that recorded on Schedule 1 as non-deductible company pension plans relating to the increase in BPI's employee future benefits.

**Table 4.44 OPEB and Pension amounts per benefits expense in comparison to T2 Schedule 1**

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Employee future benefits per Exhibit 4, Table 4.# | 220,062 | 244,532 | 215,393 | 175,099 | 302,001 | 108,001 |
| Less: retiree benefits paid in the year | (115,995) | (127,702) | (115,859) | (94,547) | (302,000) | (108,001) |
| Less: increase in future benefits liability reported per T2S(1) | (104,067) | (116,830) | (115,758) | (80,552) | | |
| Add: accounting coding error between Accounts 5605 & 5645 | | | 16,224 | | | |
| difference = rounding | - | - | - | - | 1 | - |

- *Integrity Check:* The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.

*Confirmation:* Below Table 4.45 displays actual tax rates used by BPI in this Cost-of-Service Rate Application.

**Table 4.45 - Tax rate per Application in comparison to tax facts**

| | 2011 | 2012 | 2013 |
|---|---|---|---|
| Federal - actual | 16.50 | 15.00 | 15.00 |
| Provincial - actual | 11.75 | 11.50 | 11.50 |
| PILs model | (28.25) | (26.50) | (26.50) |
| | - | - | - |

# APPENDIX D

# PILs MODEL – 2012 & 2013

# Adjusted Taxable Income - Historic Year

| | T2S1 line # | Total for Legal Entity | Non-Distribution Eliminations | Historic Wires Only |
|---|---|---|---|---|
| **Income before PILs/Taxes** | A | 3,059,646 | | 3,059,646 |
| **Additions:** | | | | |
| Interest and penalties on taxes | 103 | | | 0 |
| Amortization of tangible assets | 104 | 4,113,716 | | 4,113,716 |
| Amortization of intangible assets | 106 | | | 0 |
| Recapture of capital cost allowance from Schedule 8 | 107 | | | 0 |
| Gain on sale of eligible capital property from Schedule 10 | 108 | | | 0 |
| Income or loss for tax purposes- joint ventures or partnerships | 109 | | | 0 |
| Loss in equity of subsidiaries and affiliates | 110 | | | 0 |
| Loss on disposal of assets | 111 | | | 0 |
| Charitable donations | 112 | 1,450 | | 1,450 |
| Taxable Capital Gains | 113 | | | 0 |
| Political Donations | 114 | | | 0 |
| Deferred and prepaid expenses | 116 | | | 0 |
| Scientific research expenditures deducted on financial statements | 118 | | | 0 |
| Capitalized interest | 119 | | | 0 |
| Non-deductible club dues and fees | 120 | | | 0 |
| Non-deductible meals and entertainment expense | 121 | 1,834 | | 1,834 |
| Non-deductible automobile expenses | 122 | | | 0 |
| Non-deductible life insurance premiums | 123 | | | 0 |
| Non-deductible company pension plans | 124 | | | 0 |
| Tax reserves deducted in prior year | 125 | 2,508,520 | | 2,508,520 |
| Reserves from financial statements- balance at end of year | 126 | 3,651,679 | | 3,651,679 |
| Soft costs on construction and renovation of buildings | 127 | | | 0 |
| Book loss on joint ventures or partnerships | 205 | | | 0 |
| Capital items expensed | 206 | | | 0 |
| Debt issue expense | 208 | | | 0 |
| Development expenses claimed in current year | 212 | | | 0 |
| Financing fees deducted in books | 216 | | | 0 |
| Gain on settlement of debt | 220 | | | 0 |
| Non-deductible advertising | 226 | | | 0 |
| Non-deductible interest | 227 | | | 0 |
| Non-deductible legal and accounting fees | 228 | | | 0 |
| Recapture of SR&ED expenditures | 231 | | | 0 |
| Share issue expense | 235 | | | 0 |
| Write down of capital property | 236 | | | 0 |
| Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2) | 237 | | | 0 |
| ***Other Additions*** | | | | |
| Interest Expensed on Capital Leases | 290 | | | 0 |
| Realized Income from Deferred Credit Accounts | 291 | | | 0 |
| Pensions | 292 | | | 0 |
| Non-deductible penalties | 293 | | | 0 |
| | 294 | | | 0 |
| | 295 | | | 0 |
| ARO Accretion expense | | | | 0 |
| Capital Contributions Received (ITA 12(1)(x)) | | | | 0 |
| Lease Inducements Received (ITA 12(1)(x)) | | | | 0 |
| Deferred Revenue (ITA 12(1)(a)) | | | | 0 |
| Prior Year Investment Tax Credits received | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| **Total Additions** | | **10,277,199** | **0** | **10,277,199** |

| | | | | |
|---|---|---|---|---|
| **Deductions:** | | | | |
| Gain on disposal of assets per financial statements | 401 | 19,025 | | 19,025 |
| Dividends not taxable under section 83 | 402 | | | 0 |
| Capital cost allowance from Schedule 8 | 403 | 4,172,471 | | 4,172,471 |
| Terminal loss from Schedule 8 | 404 | | | 0 |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 47,014 | | 47,014 |
| Allowable business investment loss | 406 | | | 0 |
| Deferred and prepaid expenses | 409 | | | 0 |
| Scientific research expenses claimed in year | 411 | | | 0 |
| Tax reserves claimed in current year | 413 | 2,073,612 | | 2,073,612 |
| Reserves from financial statements - balance at beginning of year | 414 | 3,934,035 | | 3,934,035 |
| Contributions to deferred income plans | 416 | | | 0 |
| Book income of joint venture or partnership | 305 | | | 0 |
| Equity in income from subsidiary or affiliates | 306 | | | 0 |
| *Other deductions: (Please explain in detail the nature of the item)* | | | | |
| | | | | |
| Interest capitalized for accounting deducted for tax | 390 | | | 0 |
| Capital Lease Payments | 391 | | | 0 |
| Non-taxable imputed interest income on deferral and variance accounts | 392 | | | 0 |
| | 393 | | | 0 |
| Previously capitalized overhead | 394 | 1,162,134 | | 1,162,134 |
| ARO Payments - Deductible for Tax when Paid | | | | 0 |
| ITA 13(7.4) Election - Capital Contributions Received | | | | 0 |
| ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds | | | | 0 |
| Deferred Revenue - ITA 20(1)(m) reserve | | | | 0 |
| Principal portion of lease payments | | | | 0 |
| Lease Inducement Book Amortization credit to income | | | | 0 |
| Financing fees for tax ITA 20(1)(e) and (e.1) | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | 0 |
| | | | | |
| **Total Deductions** | | **11,408,291** | **0** | **11,408,291** |
| | | | | |
| **Net Income for Tax Purposes** | | **1,928,554** | **0** | **1,928,554** |
| | | | | |
| Charitable donations from Schedule 2 | 311 | | | 0 |
| Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82) | 320 | | | 0 |
| Non-capital losses of preceding taxation years from Schedule 4 | 331 | | | 0 |
| Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)* | 332 | | | 0 |
| Limited partnership losses of preceding taxation years from Schedule 4 | 335 | | | 0 |
| | | | | |
| **TAXABLE INCOME** | | **1,928,554** | **0** | **1,928,554** |

## TAX CALCULATIONS

Table 4.46 below provides a summary of 2008 Board Approved, the 2008, 2009, 2010 and 2011 actual, included in audited financial statements, and the 2012 Bridge Year and 2013 Test Year income tax forecast. Copies of BPI's annual federal and provincial tax returns have been provided as Appendix E to this Exhibit.

**Table 4.46 – Summary of Income & Capital Taxes 2008 to 2013**

| Description | 2008 Board Approved | 2008 Actual | 2009 Actual | 2010 Actual | 2011 Actual | 2012 Bridge | 2013 Test |
|---|---|---|---|---|---|---|---|
| Income Taxes - Current | $ 1,237,171 | $ 2,754,613 | $ 1,930,422 | $ 1,120,928 | $ (258,956) | $ 497,030 | $(783,636) |
| Less: Prior Period Adjustments | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ontario Capital Tax | $ 122,854 | $ 113,116 | $ 151,200 | $ 24,236 | $ (1,318) | $ - | $ - |
| Total | $ 1,360,025 | $ 2,867,729 | $ 2,081,622 | $ 1,145,164 | $ (260,274) | $ 497,030 | $(783,636) |

BPI's detailed tax calculations using the most recent tax rates are provided in Table 4.47. BPI does not receive any tax credits.

## Table 4.47 – Detailed Tax Calculations for 2009 to 2013

| Item | 2008 Actual | 2009 Actual | 2010 Actual | 2011 Actual | 2012 Bridge Year | 2013 Test Year |
|---|---|---|---|---|---|---|
| **Accounting Net Income Before Taxes** | $ 3,259,818 | $ 3,106,967 | $ 3,480,384 | $ 3,059,646 | $ 1,083,093 | $ 2,794,528 |
| | | | | | | |
| **Additions:** | | | | | | |
| Amortization of tangible assets | $ 3,276,505 | $ 3,442,012 | $ 3,641,081 | $ 4,113,716 | $ 4,040,268 | $ 2,793,428 |
| Charitable donations | $ - | $ - | $ 7,075 | $ 1,450 | $ 1,300 | $ 1,300 |
| Non-deductible meals and entertainment expense | $ 4,301 | $ 3,164 | $ 2,431 | $ 1,834 | $ 3,958 | $ 6,566 |
| Tax reserves beginning of year | $ - | | | $ 2,508,520 | $ 2,073,612 | $ 1,860,150 |
| Reserves from financial statements- balance at end of year | $ 1,064,927 | $ 1,270,757 | $ 3,934,035 | $ 3,651,679 | $ 2,924,763 | $ 2,983,258 |
| Interest and Penalties on Taxes | $ 21,224 | | | | | |
| Taxable Capital Gains on Schedule 6 | $ 2,463 | $ 2,463 | $ 3,694 | | | |
| Loss on Disposal of Assets | $ - | $ 22,969 | | | | |
| **Total Additions** | $ 4,369,420 | $ 4,741,365 | $ 7,588,316 | $ 10,277,199 | $ 9,043,901 | $ 7,644,702 |
| | | | | | | |
| **Deductions:** | | | | | | |
| Capital Cost Allowance from Schedule 8 | $ 3,410,315 | $ 3,637,692 | $ 3,882,824 | $ 4,172,471 | $ 4,250,887 | $ 4,376,304 |
| Cumulative eligible capital deduction from Schedule 10 | $ 58,449 | $ 54,358 | $ 50,553 | $ 47,014 | $ 47,120 | $ 43,821 |
| Tax reserves end of year | $ - | | $ 2,508,520 | $ 2,073,612 | $ 1,860,150 | $ 1,625,000 |
| Reserves from financial statements - balance at beginning of year | $ 960,860 | $ 1,064,927 | $ 1,270,757 | $ 3,934,035 | $ 1,578,067 | $ 2,924,763 |
| Other Deductions | $ 4,550 | $ - | $ 51,067 | $ 19,025 | $ 1,033,000 | |
| Previously Capitalized Overheads | $ - | $ - | | $ 1,162,134 | | |
| **Total Deductions** | $ 4,434,174 | $ 4,756,977 | $ 7,763,721 | $ 11,408,291 | $ 8,769,223 | $ 8,969,888 |
| | | | | | | |
| **Total Tax Adjustments to Accounting Income** | $ (64,754) | $ (15,612) | $ (175,405) | $ (1,131,092) | $ 274,678 | $ (1,325,186) |
| | | | | | | |
| **Regulatory Taxable Income** | $ 3,195,064 | $ 3,091,355 | $ 3,304,979 | $ 1,928,554 | $ 1,357,771 | $ 1,469,342 |
| | | | | | | |
| Effective Tax Rate (Federal & Provincial) | 34% | 33% | 31% | 28.17% | 23.92% | 24.12% |
| | | | | | | |
| **Income Taxes Before Credits** | $ 1,086,322 | $ 1,020,147 | $ 1,024,543 | $ 543,274 | $ 324,779 | $ 354,405 |
| **Income Taxes After Credits** | $ 1,086,322 | $ 1,020,147 | $ 1,024,543 | $ 543,274 | $ 324,779 | $ 354,405 |
| | | | | | | |
| **Capital Tax Calculation:** | | | | | | |
| Total Rate Base | $ 69,637,867 | $ 71,086,210 | $ 73,714,414 | $ 75,595,523 | $ 76,015,169 | $ 78,748,369 |
| Reduction | 0 | 0 | 0 | 0 | 0 | 0 |
| Rate | 0.225% | 0.225% | | | | 0 |
| | | | | | | |
| **Capital Tax As Calculated** | $ 156,685 | $ 159,944 | | | 0 | 0 |
| **Capital Tax - Per Audited Financial Statements** | $ 113,116 | $ 151,200 | $ 24,236 | $ (1,318) | $ - | $ - |

# APPENDIX E

# 2011 FEDERAL & ONTARIO TAX RETURN

Canada Revenue Agency / Agence du revenu du Canada

# Business Consent form

Complete this form to consent to the release of confidential information about your program account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre (see Instructions).** Make sure you complete this form correctly, since we cannot change the information that you provided. You can also give **or** cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount.**

**Note:** Read all the instructions on the first page before completing this form.

## Part 1 – Business information

Complete this part to identify your business (all fields have to be completed)

Business name: BRANTFORD POWER INC.

BN: 865858773 Telephone number: (519) 751-3522

## Part 2 – Authorize a representative – Complete either part a) or b)

**a) Authorize access by telephone, fax, mail or in person by appointment**

If you are giving consent for an individual, enter that person's full name. If you are giving consent to a firm, enter the name and BN of the firm. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the firm's name and BN. If you do not identify an individual of the firm, then you are giving us consent to deal with anyone from that firm.

**Note:** If you are authorizing a representative (individual or firm) who is not registered with the "Represent a Client" service, the phone number is required.

Name of Individual: ____________________

Name of Firm: ____________________

Telephone number: ________ Extension: ________ BN: ________

**or**

**b) Authorize online access (includes access by telephone, fax, mail or by appointment)**

You can authorize your representative to deal with us through our online service for representatives. The BN must be registered with the "Represent a Client" service to be an online representative. **Our online service does not have a year-specific option, so your representative will have access to all years.** Please enter the name and RepID of the individual or the name of the group and GroupID **or** name and BN of the firm.

Name of individual: ____________________ **and** RepID: ________

**or**

Name of group: ____________________ **and** GroupID: G

**or**

Name of firm: KPMG LLP **and** BN: 122363153

Telephone number: (905) 523-8200 Extension: ________

## Part 3 – Select the program accounts, years and authorization level

**a) Program Accounts** – Select the program accounts the above individual or firm is authorized to access (tick only box A **or** B).

**A.** [X] This authorization applies to all program accounts and all years.

Expiry date: ________

**and**

**Authorization level (tick level 1 or 2)**

[X] Level 1 lets CRA disclose information only on your program account(s); **or**

[ ] Level 2 lets CRA disclose information **and** accept changes to your program account(s).

**or**

**B.** [ ] This authorization applies only to program accounts and periods listed in Part 3b). If you ticked this option, you must complete 3b).

# Business Consent form

## Part 3 – Select the program accounts, years and authorization level (continued)

**b) Details of program accounts and fiscal periods** – Complete this area only if you ticked box B in Part 3a) on page 1.

If you ticked box B in part 3a), you have to provide at least one program identifier. You can then tick the box "All program accounts" for that program identifier **or** enter a reference number. Provide the authorization level (tick **either** box 1 to allow the CRA to disclose information **or** box 2 to disclose information **and** accept changes to your program account).

You can also tick the box "All years" to allow unlimited tax year access **or** enter a specific fiscal period (specific period authorization **is not available** for online access). You can also enter an expiry date to automatically cancel authorization. If more authorizations or more than four program identifiers are needed, complete another Form RC59.

| Program identifier | All program accounts | | Reference number | Authorization level | | All years | or | Specific fiscal period (not available for online access) | Expiry date |
|---|---|---|---|---|---|---|---|---|---|
| | | | | 1 | 2 | | | Year-end | |
| | | or | | | | | or | | |
| | | or | | | | | or | | |
| | | or | | | | | or | | |
| | | or | | | | | or | | |

## Part 4 – Cancel one or more authorizations

Complete this part **only** to cancel authorization(s)

**A.** ☐ Cancel **all** authorizations.

**B.** ☐ Cancel authorization for the individual, group, or firm identified below.

**C.** ☐ Cancel authorization for specific program account(s) ______________________

Name of individual: ______________________ **and** **RepID:** ______

**or**

Name of group: ______________________ **and** **GroupID:** G

**or**

Name of firm: ______________________ **and** **BN:** ______

Telephone number: ______________________

## Part 5 – Certification

This form has to be signed by an authorized person of the business such as an owner, a partner of a partnership, a director of a corporation, an officer of a non-profit organization or a trustee of an estate.
By signing and dating this form, you authorize the CRA to deal with the individual, group, or firm listed in Part 2 of this form or cancel the authorizations listed in Part 4.

First name: BRIAN Last name: D'AMBOISE

Sign here: ► ______________________ Date: ______

This form will not be processed unless it is signed and dated by an authorized person of the business.

*Privacy Act*, Personal Information Bank numbers CRA PPU 175 and CRA PPU 223

Canada Revenue Agency | Agence du revenu du Canada

# T2 CORPORATION INCOME TAX RETURN

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide.*

## Identification

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

**Corporation's name**

002 BRANTFORD POWER INC.

**Address of head office**

Has this address changed since the last time we were notified? . . . . . . . . . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 84 MARKET SQUARE

012 P.O. BOX 308

| City | Province, territory, or state |
|---|---|
| 015 BRANTFORD | 016 ON |
| **Country (other than Canada)** | **Postal code/Zip code** |
| 017 CA | 018 N3T 5N8 |

**Mailing address** (if different from head office address)

Has this address changed since the last time we were notified? . . . . . . . . . . . 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

| City | Province, territory, or state |
|---|---|
| 025 | 026 |
| **Country (other than Canada)** | **Postal code/Zip code** |
| 027 | 028 |

**Location of books and records**

Has the location of books and records changed since the last time we were notified? . . . . . . . . . . . . . . . . . . . . . 030 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 84 MARKET SQUARE

032 P.O. BOX 308

| City | Province, territory, or state |
|---|---|
| 035 BRANTFORD | 036 ON |
| **Country (other than Canada)** | **Postal code/Zip code** |
| 037 CA | 038 N3T 5N8 |

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

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

**To which tax year does this return apply?**

Tax year start 060 2011-01-01 (YYYY MM DD) — Tax year-end 061 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . . . . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . . . . . . . . . . 065 ________ YYYY MM DD

**Is the date on line 061 a deemed tax year-end according to:**

subparagraph 88(2)(a)(iv)? . . . . . . . . 064 1 Yes [ ] 2 No [X]

subsection 249(3.1)? . . . . . . . . . . . 066 1 Yes [ ] 2 No [X]

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

**Is this the first year of filing after:**

Incorporation? . . . . . . . . . . . . . . . 070 1 Yes [ ] 2 No [X]

Amalgamation? . . . . . . . . . . . . . . . 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

**Has there been a wind-up of a subsidiary under section 88 during the current tax year?** . . . . . . . . . . . . . . 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

**Is this the final tax year before amalgamation?** . . . . . . . . . . 076 1 Yes [ ] 2 No [X]

**Is this the final return up to dissolution?** . . . . . . . . . . . . . . . . . . 078 1 Yes [ ] 2 No [X]

**If an election was made under section 261, state the functional currency used** . . . . . . . . . . . . . . . . 079 ________

**Is the corporation a resident of Canada?**

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ________

**Is the non-resident corporation claiming an exemption under an income tax treaty?** . . . . . . . . . . . 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

**If the corporation is exempt from tax under section 149, tick one of the following boxes:**

085

1 [ ] Exempt under paragraph 149(1)(e) or (l)

2 [ ] Exempt under paragraph 149(1)(j)

3 [ ] Exempt under paragraph 149(1)(t)

4 [ ] Exempt under other paragraphs of section 149

**Do not use this area**

095 096

## Attachments

**Financial statement information:** Use GIFI schedules 100, 125, and 141.
**Schedules** – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

| Question | Line | Yes | Schedule |
|---|---|---|---|
| Is the corporation related to any other corporations? | 150 | X | 9 |
| . Is the corporation an associated CCPC? | 160 | X | 23 |
| . Is the corporation an associated CCPC that is claiming the expenditure limit? | 161 | | 49 |
| Does the corporation have any non-resident shareholders? | 151 | | 19 |
| . Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents | 162 | | 11 |
| If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee? | 163 | | 44 |
| Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada? | 164 | X | 14 |
| Is the corporation claiming a deduction for payments to a type of employee benefit plan? | 165 | | 15 |
| Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989? | 166 | | T5004 |
| Is the corporation a member of a partnership for which a partnership identification number has been assigned? | 167 | | T5013 |
| Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)? | 168 | | 22 |
| Did the corporation have any foreign affiliates during the year? | 169 | | 25 |
| Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*? | 170 | | 29 |
| Has the corporation had any non-arm's length transactions with a non-resident? | 171 | | T106 |
| For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares? | 173 | X | 50 |
| Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year? | 172 | | ——— |
| Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes? | 201 | X | 1 |
| Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine? | 202 | X | 2 |
| Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund? | 203 | X | 3 |
| Is the corporation claiming any type of losses? | 204 | X | 4 |
| Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction? | 205 | | 5 |
| Has the corporation realized any capital gains or incurred any capital losses during the tax year? | 206 | X | 6 |
| i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440? | 207 | | 7 |
| Does the corporation have any property that is eligible for capital cost allowance? | 208 | X | 8 |
| Does the corporation have any property that is eligible capital property? | 210 | X | 10 |
| Does the corporation have any resource-related deductions? | 212 | | 12 |
| Is the corporation claiming deductible reserves? | 213 | X | 13 |
| . Is the corporation claiming a patronage dividend deduction? | 216 | | 16 |
| Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction? | 217 | | 17 |
| Is the corporation an investment corporation or a mutual fund corporation? | 218 | | 18 |
| Is the corporation carrying on business in Canada as a non-resident corporation? | 220 | | 20 |
| Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits? | 221 | | 21 |
| Does the corporation have any Canadian manufacturing and processing profits? | 227 | | 27 |
| Is the corporation claiming an investment tax credit? | 231 | | 31 |
| . Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures? | 232 | | T661 |
| Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000? | 233 | X | ——— |
| Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? | 234 | X | ——— |
| Is the corporation claiming a surtax credit? | 237 | | 37 |
| . Is the corporation subject to gross Part VI tax on capital of financial institutions? | 238 | | 38 |
| . Is the corporation claiming a Part I tax credit? | 242 | | 42 |
| Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid? | 243 | | 43 |
| Is the corporation agreeing to a transfer of the liability for Part VI.1 tax? | 244 | | 45 |
| Is the corporation subject to Part II - Tobacco Manufacturers' surtax? | 249 | | 46 |
| For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax? | 250 | | 39 |
| Is the corporation claiming a Canadian film or video production tax credit refund? | 253 | | T1131 |
| Is the corporation claiming a film or video production services tax credit refund? | 254 | | T1177 |
| Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.) | 255 | | 92 |

## Attachments – continued from page 2

| | Code | Yes | Schedule |
|---|---|---|---|
| Did the corporation have any foreign affiliates that are not controlled foreign affiliates? | 256 | | T1134-A |
| Did the corporation have any controlled foreign affiliates? | 258 | | T1134-B |
| Did the corporation own specified foreign property in the year with a cost amount over $100,000? | 259 | | T1135 |
| Did the corporation transfer or loan property to a non-resident trust? | 260 | | T1141 |
| Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year? | 261 | | T1142 |
| Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada? | 262 | | T1145 |
| Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts? | 263 | | T1146 |
| Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED? | 264 | | T1174 |
| Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year? | 265 | X | 55 |
| Has the corporation made an election under subsection 89(11) not to be a CCPC? | 266 | | T2002 |
| Has the corporation revoked any previous election made under subsection 89(11)? | 267 | | T2002 |
| Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year? | 268 | X | 53 |
| Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year? | 269 | | 54 |

## Additional information

| | Code | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Is the corporation inactive? | 280 | | X |

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

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.

| Product/service | % |
|---|---|
| ELECTRICITY DISTRIBUTION | 100.000 % |
| | % |
| | % |

| | Code | 1 Yes | 2 No |
|---|---|---|---|
| Did the corporation immigrate to Canada during the tax year? | 291 | | X |
| Did the corporation emigrate from Canada during the tax year? | 292 | | X |
| Do you want to be considered as a quarterly instalment remitter if you are eligible? | 293 | | |

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

| | Code | 1 Yes | 2 No |
|---|---|---|---|
| If the corporation's major business activity is construction, did you have any subcontractors during the tax year? | 295 | | |

## Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI. 300 -1,200,833 A

| | | Code | Amount | | |
|---|---|---|---|---|---|
| **Deduct:** | Charitable donations from Schedule 2 | 311 | | | |
| | Gifts to Canada, a province, or a territory from Schedule 2 | 312 | | | |
| | Cultural gifts from Schedule 2 | 313 | | | |
| | Ecological gifts from Schedule 2 | 314 | | | |
| | Gifts of medicine from Schedule 2 | 315 | | | |
| | Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3 | 320 | | | |
| | Part VI.1 tax deduction* | 325 | | | |
| | Non-capital losses of previous tax years from Schedule 4 | 331 | | | |
| | Net capital losses of previous tax years from Schedule 4 | 332 | | | |
| | Restricted farm losses of previous tax years from Schedule 4 | 333 | | | |
| | Farm losses of previous tax years from Schedule 4 | 334 | | | |
| | Limited partnership losses of previous tax years from Schedule 4 | 335 | | | |
| | Taxable capital gains or taxable dividends allocated from a central credit union | 340 | | | |
| | Prospector's and grubstaker's shares | 350 | | | |
| | Subtotal | | | | B |
| | Subtotal (amount A **minus** amount B) (if negative, enter "0") | | | | C |
| **Add:** | Section 110.5 additions or subparagraph 115(1)(a)(vii) additions | 355 | | | D |
| **Taxable income** (amount C **plus** amount D) | | 360 | | | |
| Income exempt under paragraph 149(1)(t) | | 370 | | | |
| **Taxable income** for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370) | | | | | Z |

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

## Small business deduction

**Canadian-controlled private corporations (CCPCs) throughout the tax year**

Income from active business carried on in Canada from Schedule 7 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 400 ____ A

Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 405 ____ B

Business limit (see notes 1 and 2 below) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 410 ____ C

**Notes:**

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

**Business limit reduction:**

Amount C ____ x 415 ***** 184,200 D / 11,250 = . . . . . . . . . . . . . . . . . . . . . . . . ____ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 425 ____ F

**Small business deduction**

Amount A, B, C, or F, whichever is the least ____ x 17 % = . . . . . . . . . . . . . . . . . . . . . . 430 ____ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

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

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

## General tax reduction for Canadian-controlled private corporations

**Canadian-controlled private corporations throughout the tax year**

Taxable income from line 360 on page 3* . . . . . . . . . . . . . . . . . . . . . . A

Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 . . . . . . . B

Amount QQ from Part 13 of Schedule 27 . . . . . . . C

Personal service business income** . . . . . . . 432 D

Amount used to calculate the credit union deduction from Schedule 17 . . . . . . . E

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . . . F

Aggregate investment income from line 440 on page 6*** . . . . . . . G

Total of amounts B to G . . . . . . . ▶ H

Amount A **minus** amount H (if negative, enter "0") . . . . . . . I

Amount I x (Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365) x 9 % = J

Amount I x (Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365) x 10 % = K

Amount I x (Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365) x 11.5 % = L

Amount I x (Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365) x 13 % = M

**General tax reduction for Canadian-controlled private corporations** – Total of amounts J to M . . . . . . . N
Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

## General tax reduction

**Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.**

Taxable income from page 3 (line 360 or amount Z, whichever applies) . . . . . . . O

Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 . . . . . . . P

Amount QQ from Part 13 of Schedule 27 . . . . . . . Q

Personal service business income* . . . . . . . 434 R

Amount used to calculate the credit union deduction from Schedule 17 . . . . . . . S

Total of amounts P to S . . . . . . . ▶ T

Amount O **minus** amount T (if negative, enter "0") . . . . . . . U

Amount U x (Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365) x 9 % = V

Amount U x (Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365) x 10 % = W

Amount U x (Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365) x 11.5 % = X

Amount U x (Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365) x 13 % = Y

**General tax reduction** – Total of amounts V to Y . . . . . . . Z
Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

## Refundable portion of Part I tax

**Canadian-controlled private corporations throughout the tax year**

| | | | | |
|---|---|---|---|---|
| Aggregate investment income from Schedule 7 | 440 | x 26 2/3 % = | | A |
| Foreign non-business income tax credit from line 632 on page 7 | | | | |
| **Deduct:** Foreign investment income from Schedule 7 | 445 | x 9 1/3 % = | | |
| (if negative, enter "0") | | | ▶ | B |
| Amount A **minus** amount B (if negative, enter "0") | | | | C |
| Taxable income from line 360 on page 3 | | | | |
| **Deduct:** | | | | |
| Amount from line 400, 405, 410, or 425 on page 4, whichever is the least | | | | |
| Foreign non-business income tax credit from line 632 on page 7 | | 25/9* x 25 / 9 = | | |
| Foreign business income tax credit from line 636 on page 7 | | x 1(0.38 - X**) / 3.77358 = | | |
| | | | ▶ | |
| | | x 26 2/3 % = | | D |
| Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) | | | | E |
| **Refundable portion of Part I tax** – Amount C, D, or E, whichever is the least | 450 | | | F |

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

## Refundable dividend tax on hand

| | | | | |
|---|---|---|---|---|
| Refundable dividend tax on hand at the end of the previous tax year | 460 | 985 | | |
| **Deduct:** Dividend refund for the previous tax year | 465 | 985 | | |
| | | | ▶ | G |
| **Add** the total of: | | | | |
| Refundable portion of Part I tax from line 450 above | | | | |
| Total Part IV tax payable from Schedule 3 | | | | |
| Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation | 480 | | | |
| | | | ▶ | H |
| **Refundable dividend tax on hand at the end of the tax year** – Amount G **plus** amount H | 485 | | | |

## Dividend refund

**Private and subject corporations at the time taxable dividends were paid in the tax year**

| | | | | |
|---|---|---|---|---|
| Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 | 1,450,000 | x 1 / 3 | 483,333 | I |
| Refundable dividend tax on hand at the end of the tax year from line 485 above | | | | J |
| **Dividend refund** – Amount I or J, whichever is less (enter this amount on line 784 on page 8) | | | | |

## Part I tax

**Base amount of Part I tax** – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % **550** ____ A

**Recapture of investment tax credit from Schedule 31** . . . . . **602** ____ B

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

Aggregate investment income from line 440 on page 6 . . . . . ____ i

Taxable income from line 360 on page 3 . . . . . ____

**Deduct:**

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . ____

Net amount . . . . . ____ ► ____ ii

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

Subtotal (**add** lines A to C) ____ D

**Deduct:**

Small business deduction from line 430 on page 4 . . . . . ____ 1

Federal tax abatement . . . . . **608** ____

Manufacturing and processing profits deduction from Schedule 27 . . . . . **616** ____

Investment corporation deduction . . . . . **620** ____

Taxed capital gains **624** ____

Additional deduction – credit unions from Schedule 17 . . . . . **628** ____

Federal foreign non-business income tax credit from Schedule 21 . . . . . **632** ____

Federal foreign business income tax credit from Schedule 21 . . . . . **636** ____

General tax reduction for CCPCs from amount N on page 5 . . . . . **638** ____

General tax reduction from amount Z on page 5 . . . . . **639** ____

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

Federal qualifying environmental trust tax credit . . . . . **648** ____

Investment tax credit from Schedule 31 . . . . . **652** ____

Subtotal ____ ► ____ E

**Part I tax payable** – Line D **minus** line E . . . . . ____ F

Enter amount F on line 700 on page 8.

## Summary of tax and credits

**Federal tax**

| | | |
|---|---|---|
| Part I tax payable from page 7 | 700 | |
| Part II surtax payable from Schedule 46 | 708 | |
| Part III.1 tax payable from Schedule 55 | 710 | |
| Part IV tax payable from Schedule 3 | 712 | |
| Part IV.1 tax payable from Schedule 43 | 716 | |
| Part VI tax payable from Schedule 38 | 720 | |
| Part VI.1 tax payable from Schedule 43 | 724 | |
| Part XIII.1 tax payable from Schedule 92 | 727 | |
| Part XIV tax payable from Schedule 20 | 728 | |
| Total federal tax | | |

**Add provincial or territorial tax:**

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

| | | |
|---|---|---|
| Net provincial or territorial tax payable (except Quebec and Alberta) | 760 | |
| Provincial tax on large corporations (Nova Scotia Schedule 342) | 765 | |

Total tax payable 770 ______ A

**Deduct other credits:**

| | | |
|---|---|---|
| Investment tax credit refund from Schedule 31 | 780 | |
| Dividend refund from page 6 | 784 | |
| Federal capital gains refund from Schedule 18 | 788 | |
| Federal qualifying environmental trust tax credit refund | 792 | |
| Canadian film or video production tax credit refund (Form T1131) | 796 | |
| Film or video production services tax credit refund (Form T1177) | 797 | |
| Tax withheld at source | 800 | |
| Total payments on which tax has been withheld | 801 | |
| Provincial and territorial capital gains refund from Schedule 18 | 808 | |
| Provincial and territorial refundable tax credits from Schedule 5 | 812 | |
| Tax instalments paid | 840 | |
| Total credits | 890 | |

______ B

Refund code 894 1 Overpayment ______

Balance (line A **minus** line B) ______

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . . . . . ______

Enclosed payment 898 ______

### Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

## Certification

I, 950 D'AMBOISE (Last name in block letters) 951 BRIAN (First name in block letters) 954 CEO/CFO (Position, office, or rank),
am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 ______ Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (519) 751-3522 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . . . . . . 957 1 Yes ☒ 2 No ☐

958 ______ Name in block letters 959 ______ Telephone number

## Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 100**

Form identifier 100

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Assets** | | | | |
| | Total current assets | 1599 | + | 28,634,115 | 31,439,231 |
| | Total tangible capital assets | 2008 | + | 59,873,172 | 58,307,002 |
| | Total accumulated amortization of tangible capital assets | 2009 | – | | |
| | Total intangible capital assets | 2178 | + | 3,479,311 | 4,547,613 |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | 7,452,973 | 9,836,450 |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 99,439,571 | 104,130,296 |
| | **Liabilities** | | | | |
| | Total current liabilities | 3139 | + | 14,303,812 | 16,386,487 |
| | Total long-term liabilities | 3450 | + | 50,857,627 | 54,161,668 |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | 65,161,439 | 70,548,155 |
| | **Shareholder equity** | | | | |
| | **Total shareholder equity** (mandatory field) | 3620 | + | 34,278,132 | 33,582,141 |
| | **Total liabilities and shareholder equity** | 3640 | = | 99,439,571 | 104,130,296 |
| | **Retained earnings** | | | | |
| | **Retained earnings/deficit – end** (mandatory field) | 3849 | = | 12,358,906 | 11,519,294 |

* Generic item

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SCHEDULE 100

# Current Assets

Form identifier 1599

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| **Cash and deposits** | | | | | |
| * | Cash and deposits | 1000 | | 9,200,282 | 11,180,750 |
| | **Cash and deposits** | | + | 9,200,282 | 11,180,750 |
| **Accounts receivable** | | | | | |
| * | Accounts receivable | 1060 | | 7,373,814 | 8,483,553 |
| | Taxes receivable | 1066 | | 1,262,583 | 584,850 |
| | **Accounts receivable** | | + | 8,636,397 | 9,068,403 |
| **Inventories** | | | | | |
| * | Inventories | 1120 | | 718,936 | 819,450 |
| | Work in progress | 1125 | | 8,636,720 | 8,995,538 |
| | **Inventories** | | + | 9,355,656 | 9,814,988 |
| **Other current assets** | | | | | |
| * | Other current assets | 1480 | | 1,155,522 | 1,056,193 |
| | Future (deferred) income taxes | 1481 | | 178,500 | 171,760 |
| | Prepaid expenses | 1484 | | 107,758 | 147,137 |
| | **Other current assets** | | + | 1,441,780 | 1,375,090 |
| | **Total current assets** | 1599 | = | 28,634,115 | 31,439,231 |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

**SCHEDULE 100**

# Tangible Capital Assets and Accumulated Amortization

Form identifier 2008/2009

| Account | Description | GIFI | Tangible capital assets | Accumulated amortization | Prior year |
|---|---|---|---|---|---|
| | **Other tangible capital assets** | | | | |
| * | Other tangible capital assets | 1900 | + 59,873,172 | | 58,307,002 |
| | **Total** | | 59,873,172 | | |
| | **Total tangible capital assets** | 2008 | = 59,873,172 | | 58,307,002 |
| | **Total accumulated amortization of tangible capital assets** | 2009 | | = | |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

SCHEDULE 100

# Intangible Capital Assets and Accumulated Amortization

Form identifier 2178/2179

| Account | Description | GIFI | Intangible capital assets | Accumulated amortization | Prior year |
|---|---|---|---|---|---|
| | **Intangible assets** | | | | |
| * | Intangible assets | 2010 | + 3,479,311 | | 4,547,613 |
| | **Total** | | 3,479,311 | | |
| | **Total intangible capital assets** | 2178 | = 3,479,311 | | 4,547,613 |
| | **Total accumulated amortization of intangible capital assets** | 2179 | | = | |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

# Long-term Assets

**SCHEDULE 100**

Form identifier 2589

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Other long-term assets** | | | | |
| | * Other long-term assets | 2420 | | 5,173,277 | 6,611,681 |
| | Future (deferred) income taxes | 2421 | | 2,279,696 | 3,224,769 |
| | **Other long-term assets** | | + | 7,452,973 | 9,836,450 |
| | **Total long-term assets** | 2589 | = | 7,452,973 | 9,836,450 |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

# Current Liabilities

**SCHEDULE 100**

Form identifier 3139

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Amounts payable and accrued liabilities** | | | | |
| | * Amounts payable and accrued liabilities | 2620 | | 9,357,633 | 10,822,994 |
| | Trade payables to related parties | 2622 | | 1,489,970 | 1,697,640 |
| | **Amounts payable and accrued liabilities** | | + | 10,847,603 | 12,520,634 |
| | **Due to related parties** | | | | |
| | * Due to related parties | 2860 | | 274,137 | 47,533 |
| | Interest payable to related parties | 2862 | | 1,427,564 | 1,511,823 |
| | **Due to related parties** | | + | 1,701,701 | 1,559,356 |
| | * Current portion of long-term liability | 2920 | + | 598,986 | 1,250,304 |
| | **Other current liabilities** | | | | |
| | Deposits received | 2961 | | 1,155,522 | 1,056,193 |
| | **Other current liabilities** | | + | 1,155,522 | 1,056,193 |
| | **Total current liabilities** | 3139 | = | 14,303,812 | 16,386,487 |

* Generic item

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# Long-term Liabilities

**SCHEDULE 100**

Form identifier 3450

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Long-term debt** | | | | |
| ___________* | Long-term debt | 3140 | | 40,919,451 | 40,280,376 |
| | **Long-term debt** | | + | 40,919,451 | 40,280,376 |
| | **Other long-term liabilities** | | | | |
| ___________* | Other long-term liabilities | 3320 | | 9,938,176 | 13,881,292 |
| | **Other long-term liabilities** | | + | 9,938,176 | 13,881,292 |
| ___________ | **Total long-term liabilities** | 3450 | = | 50,857,627 | 54,161,668 |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

# Shareholder Equity

**SCHEDULE 100**

Form identifier 3620

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | * Common shares | 3500 | + | 22,437,505 | 22,437,505 |
| | * Accumulated other comprehensive income | 3580 | + | -518,279 | -374,658 |
| | * Retained earnings/deficit | 3600 | + | 12,358,906 | 11,519,294 |
| | **Total shareholder equity** | 3620 | = | 34,278,132 | 33,582,141 |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

# Retained Earnings/Deficit

**SCHEDULE 100**

Form identifier 3849

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| * | Retained earnings/deficit – start | 3660 | + | 11,519,294 | 10,395,838 |
| * | Net income/loss | 3680 | + | 2,289,612 | 1,873,456 |
| | **Dividends declared** | | | | |
| * | Dividends declared | 3700 | | 1,450,000 | 750,000 |
| | **Dividends declared** | | – | 1,450,000 | 750,000 |
| | **Retained earnings/deficit – end** | 3849 | = | 12,358,906 | 11,519,294 |

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 125**

Form identifier 125

# GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

## Income statement information

| Description | GIFI | |
|---|---|---|
| Operating name | 0001 | |
| Description of the operation | 0002 | |
| Sequence number | 0003 | 01 |

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Income statement information** | | | | |
| | Total sales of goods and services | 8089 | + | 16,350,948 | 17,060,324 |
| | Cost of sales | 8518 | – | | |
| | **Gross profit/loss** | 8519 | = | 16,350,948 | 17,060,324 |
| | Cost of sales | 8518 | + | | |
| | Total operating expenses | 9367 | + | 13,901,936 | 13,995,103 |
| | **Total expenses** (mandatory field) | 9368 | = | 13,901,936 | 13,995,103 |
| | Total revenue (mandatory field) | 8299 | + | 16,961,582 | 17,475,487 |
| | Total expenses (mandatory field) | 9368 | – | 13,901,936 | 13,995,103 |
| | **Net non-farming income** | 9369 | = | 3,059,646 | 3,480,384 |
| | **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 | = | 3,059,646 | 3,480,384 |
| | **Total other comprehensive income** | 9998 | = | | |
| | **Extraordinary items and income (linked to Schedule 140)** | | | | |
| | Extraordinary item(s) | 9975 | – | | |
| | Legal settlements | 9976 | – | | |
| | Unrealized gains/losses | 9980 | + | | |
| | Unusual items | 9985 | – | | |
| | Current income taxes | 9990 | – | -258,596 | 1,120,928 |
| | Future (deferred) income tax provision | 9995 | – | 1,028,630 | 486,000 |
| | Total – Other comprehensive income | 9998 | + | | |
| | **Net income/loss after taxes and extraordinary items** (mandatory field) | 9999 | = | 2,289,612 | 1,873,456 |

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

# Revenue

**SCHEDULE 125**

Form identifier 8299

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | * Trade sales of goods and services | 8000 | + | 16,350,948 | 17,060,324 |
| | **Total sales of goods and services** | [illegible] | = | 16,350,948 | 17,060,324 |
| | **Interest income (financial institutions)** | | | | |
| | * Interest income (financial institutions) | 8100 | | 278,195 | 129,666 |
| | **Interest income (financial institutions)** | | + | 278,195 | 129,666 |
| | **Other revenue** | | | | |
| | * Other revenue | 8230 | | 332,439 | 285,497 |
| | **Other revenue** | | + | 332,439 | 285,497 |
| | **Total revenue** | 8299 | = | 16,961,582 | 17,475,487 |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

# Operating Expenses

**SCHEDULE 125**

Form identifier 9367

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| * | Amortization of tangible assets | 8670 | + | 3,842,300 | 3,374,841 |
| | **Interest and bank charges** | | | | |
| | Interest on long-term debt | 8714 | | 2,159,034 | 2,030,478 |
| | Bank charges | 8715 | | 195,748 | 89,606 |
| | **Interest and bank charges** | | + | 2,354,782 | 2,120,084 |
| | **Business taxes, licences, and memberships** | | | | |
| * | Business taxes, licences, and memberships | 8760 | | -1,318 | 24,236 |
| | **Business taxes, licences, and memberships** | | + | -1,318 | 24,236 |
| | **Repairs and maintenance** | | | | |
| * | Repairs and maintenance | 8960 | | 3,689,153 | 4,265,623 |
| | **Repairs and maintenance** | | + | 3,689,153 | 4,265,623 |
| | **Other expenses** | | | | |
| | General and administrative expenses | 9284 | | 4,017,019 | 4,210,319 |
| | **Other expenses** | | + | 4,017,019 | 4,210,319 |
| | **Total operating expenses** | 9367 | = | 13,901,936 | 13,995,103 |

***** Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 141**

# NOTES CHECKLIST

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . 097 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

**Note:** If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

## Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 1 Yes [ ] 2 No [X]

## Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) . . . . . 1 [X]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 101 1 Yes [ ] 2 No [ ]
X

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . . 105 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . 106 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . 107 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 1 Yes [ ] 2 No [X]

Canada

## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income<br>Increase (decrease) | | In OCI<br>Increase (decrease) |
|---|---|---|---|---|
| Property, plant, and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . 255 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . 260 1 Yes [ ] 2 No [X]

**Adjustments to opening equity**

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

# T2 BAR CODE RETURN

**Name: BRANTFORD POWER INC.**

**BN: 86585 8773 RC 0001**
**Tax Year Start: 2011-01-01**
**Tax Year End: 2011-12-31**

Brantford Power Inc.

Notes to the Financial Statements

for the year ended December 31, 2011

1. Incorporation

On March 1, 2000, Brantford Power Inc. (the Company) was incorporated under
the Business
Corporations Act (Ontario) along with its affiliate companies, Brantford Hydro
Inc. and
Brantford Energy Corporation. Another affiliated company, Brantford Generation
Inc., was
incorporated in 2007. The incorporations were pursuant to the provisions of
the Energy
Competition Act, 1998. The Company is a wholly-owned subsidiary of Brantford
Energy
Corporation. The Company provides electricity distribution services to
residents of the City of
Brantford. The operations of the company are regulated by the Ontario Energy
Board (OEB).

2. Accounting Policies

Basis of accounting

The financial statements of the Company have been prepared in accordance with
Canadian
generally accepted accounting principles (GAAP) and policies as set forth in
the Accounting
Procedures Manual issued by the OEB under the authority of the Ontario Energy
Board Act,
1998. Significant accounting policies are summarized below:

Regulation

The Company is regulated by the OEB and requires OEB approval for any

distribution service
rate adjustments. The following accounting policies applicable to rate
regulated operations
differ from GAAP for companies operating in an unregulated environment:
Regulatory assets and liabilities
Regulatory assets primarily represent costs that have been deferred because
they are
expected to be recovered in future rates. Similarly, regulatory liabilities
can arise from
differences in amounts billed to customers under the regulated pricing
mechanism and the
corresponding wholesale market cost of power incurred by the utility.
Regulatory assets and liabilities will be recognized for rate-setting and
financial statement
purposes only to the extent allowed by the regulator. The Company continually
assesses
the likelihood of recovery of each of its regulatory assets and continues to
believe that it is
probable that the OEB will factor its regulatory assets and liabilities into
the setting of
future rates. If, at some future date, the Company judges that it is no longer
probable that
the OEB will include a regulatory asset or liability in future rates, the
appropriate carrying
amount will be reflected in the results of operations in the period that the
assessment is
made. Asset and liability balances and current year activities are detailed in
Note 8.

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2. Accounting Policies - continued

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions towards the cost of constructing company assets. Capital contributions for the year of $265,560 (2010 - $196,588) have been recorded as an offset to capital assets. Amortization of contributed capital is recorded at an equivalent rate to that used for amortization of the related assets.

Allowance for use of funds during construction

The company capitalizes an allowance for use of funds during construction representing the cost of funds during the construction period. The rate used is prescribed by the OEB and updated on a quarterly basis. The total allowance for use of funds during construction capitalized for the year amounted to $56,469 (2010 - $63,402).

Stranded meters

As a result of the OEB's smart meter initiative, the Company has removed conventional meters and replaced them with smart meters. The net book value of the conventional meters removed from service prior to the end of their useful life has been classified as stranded meters and reallocated from property, plant and equipment to intangible assets.

The OEB will allow the Company to recover the costs of these stranded meters
through a
future rate application process.
Payment in lieu of income taxes
The Company is currently exempt from taxes under the Income Tax Act (Canada)
and the
Ontario Corporations Tax Act. Under the Electricity Act, 1998, the Company is
required to
make payments in lieu of corporate taxes (PILS) to the Ontario Electricity
Financial
Corporation (OEFC), beginning on October 1, 2001. These payments are recorded
in
accordance with the rules for computing income and taxable capital and other
relevant amounts
contained in the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario)
and modified
by the Electricity Act, 1998, and related regulations.
The Company uses the asset and liability method of accounting for payments in
lieu of
corporate income taxes. Accordingly, future tax assets and liabilities are
recognized for future
tax consequences attributable to differences between the financial statement
carrying amounts
of existing assets and liabilities and their respective tax rates. Future tax
assets and liabilities
are measured using enacted or substantively enacted tax rates expected to
apply to taxable
income in the year in which those temporary differences are expected to be

recovered or settled.

In addition, the effect of future tax assets and liabilities of a change in

tax rates is recognized in

income in the year that includes the enactment or substantive enactment date.

Page 11

2. Accounting Policies - continued

Use of estimates

The preparation of financial statements in conformity with Canadian GAAP

requires

management to make estimates and assumptions that affect the reported amounts

of assets and

liabilities and the disclosure and contingent assets and liabilities at the

date of the financial

statements and the reported amounts of revenues and expenses for the year.

During the years

presented, management has made a number of estimates and valuation assumptions

including

allowance for doubtful accounts receivable, unbilled revenue, useful lives,

certain accruals,

valuation of financial instruments including derivatives and future income tax

liabilities.

Estimates are based on historical experience, current trends and various other

assumptions that

are believed to be reasonable under the circumstances. Actual results could

differ from

estimates, including changes as a result of future decisions made by the OEB

or the Minister of

Energy.

Cash and cash equivalents

Cash and cash equivalents include cash and short-term investments with
maturities of three
months or less from the date of acquisition.

Inventories

Inventories consist of repair parts, supplies and materials and are valued at
the lower of cost or
net realizable value determined using a weighted average method. The Company
classifies
major construction related components of its electricity distribution system
to property, plant
and equipment.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the
last meter
reading during the year to the balance sheet date.

Page 12

2. Accounting Policies - continued

Property, plant and equipment

Property, plant and equipment are stated at cost and removed from the accounts
when disposed
or retired. Costs of assets which are pooled are removed from the accounts at
the end of their
estimated average service lives. Gains or losses at retirement or disposition
of such assets are
credited or charged to other income. Amortization is calculated on a straight-
line basis over the
estimated useful service life as follows.

Buildings 50 years Transformer

station 40 years Distribution stations

30 years Distribution lines - overhead

25 years

Distribution lines - underground 25 years

Distribution transformers 25 years

Distribution meters 25 years

Vehicles 5-8 years

Tools and other equipment 5-10 years

Capital contribution 25 years

Other electric plant and work in progress are amortized when put in service.

Intangible assets

Intangible assets are recorded at cost and amortized over their estimated

useful lives on a

straight-line basis. Stranded meters represent distribution meters that have

been replaced with

smart meters and reallocated from property, plant and equipment. The OEB has

allowed these

retired meters to remain in rate base for rate making purposes. Amortization

is calculated on a

straight-line basis over the estimated useful service life as follows.

Stranded meters 25 years

Software 5 years

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2. Accounting Policies - continued

Long-term prepaid expenses and special deposits

Long-term prepaid expenses consist of service fees paid providing the Company

with the right

to use non-owned specified tangible assets for future periods. These charges

are amortized on a

straight-line basis over 10 years representing the expected benefit period.

Amounts are recorded as special deposits when cash is collected related to

customer deposits

and are expected to be held for a period exceeding one year.

Revenue recognition

Distribution revenue is recorded as revenue in the period to which it relates.

Distribution

revenue includes an estimated accrual for the variable component of the

distribution rate based

on the electricity delivered but not yet billed to customers from the last

meter reading date to

the year end.

Other revenue is recognized as services are rendered or contract milestones

are achieved.

Impairment of long-lived assets

The Company reviews the valuation of long-term assets when events or changes

in

circumstances indicate that the assets' carrying value exceeds the total

undiscounted cash flows

expected from their use and eventual disposition. There was no impact on the

financial

statements as a result of asset impairments for the years ended December 31,

2011 and 2010.

Customer deposits

Customer deposits are cash collections from customers to guarantee the payment

of electricity

bills as prescribed by the OEB's Retail Settlement Code. Deposits expected to
be refunded to
customers within the next fiscal period are classified as a current liability.

Employee future benefits

The Company provides post-retirement medical and life insurance benefits to
eligible
employees. The cost of post-retirement medical and life insurance benefits is
expensed using
the projected benefit cost method prorated on services.

The Company has adopted the corridor method of accounting for the actuarially
determined
gains and losses. Cumulative gains and losses in excess of 10% of the
beginning accrued
benefit obligation are amortized into expense on a straight-line basis over
the expected
remaining lifetime of the inactive members receiving benefits under the plan
(15 years).

Page 14

2. Accounting Policies - continued

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from
acquisition,
construction, development or normal operations. The liability for an asset
retirement is initially
recorded at its fair value in the year in which it is incurred and when a
reasonable estimate of
fair value can be made. The corresponding cost is capitalized as part of the
related asset and is

amortized over the asset's useful life. In subsequent years, the liability is
adjusted for changes
resulting from the passage of time and revisions to either the timing or the
amount of the
original estimate of the undiscounted cash flows. Any adjustment to the
liability of its fair
value as a result of the passage of time is charged to earnings.
Comprehensive Income
CICA Handbook Section 1530 requires the presentation of comprehensive income
and its
components in a financial statement. Comprehensive income is composed of the
Company's net
income and other comprehensive income (OCI), which includes unrealized gains
and losses on
changes in the fair value of the effective portion of cash flow hedging
instruments. The
Company discloses comprehensive income in the financial statement "Statement
of
Comprehensive Income". The cumulative changes in OCI are included in
Accumulated other
comprehensive income net of tax (AOCI), which is presented as a category of
Shareholder's
equity on the Company's Balance Sheet.
Financial Instruments
The Corporation designates its financial instruments in one of the following
five categories: (i)
held for trading (HFT); (ii) available for sale (AFS); (iii) held to maturity
(HTM); (iv) loans and

receivables (LR); or (v) other liabilities (OL). All financial instruments are
initially measured at
fair value. Financial instruments classified as held for trading or available
for sale are
subsequently measured at fair value, with any change in fair value recognized
in earnings and
other comprehensive income, respectively. All other financial instruments are
subsequently
measured at amortized cost.
The Company has elected to add transaction costs related to financial
instruments classified as
other than HFT to the carrying amount of the financial instrument.
The Company has elected to use settlement-date accounting for regular-way
purchases and sales
of financial assets.
Page 15
3. Future Changes in Accounting Framework
International Financial Reporting Standards (IFRS)
In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed
that publicly
accountable enterprises would be required to adopt IFRS in place of Canadian
GAAP effective
January 1, 2011. Subsequently, in September 2010, the AcSB issued an optional
one year
deferral in adoption of IFRS for rate-regulated entities. The Company
qualifies for this deferral
and has elected to defer adoption until January 1, 2012. The adoption date of
January 1, 2012

will require the restatement, for comparative purposes, of amounts reported by the Company for
its year ended December 31, 2011, and of the opening balance sheet as at January 1, 2011.
The Company is continuing to assess the financial reporting impacts of the adoption of IFRS on
its financial statements. The Company does anticipate significant changes to those accounting
policies which are unique to rate regulated entities under Canadian GAAP. In particular, the
adoption of IFRS is expected to result in significant changes to the accounting of regulatory
assets and liabilities and to the capitalization and other accounting policies applicable to self
constructed property, plant and equipment. The Company also anticipates a significant increase
in disclosure resulting from the adoption of IFRS and is continuing to assess the level of
disclosure required. At this time, the preliminary impact on the Company's 2011 financial
position and results of operations is expected to be a reduction of pre-tax income by
approximately $2,500,000 related to rate regulation, capitalization policy changes, useful life
changes and changes in the treatment of employee future benefits.
4. Rate Setting
The rates of the Company's electricity distribution business are subject to regulation by the

OEB. The Company purchases electricity from the Independent Electricity System
Operator
(the IESO) at spot market or prescribed rates and charges its customers
unbundled rates. The
unbundled rates include the actual cost or prescribed cost of the electricity,
transmission,
wholesale market service charges and an approved rate for electricity
distribution. The cost of
electricity transmission and connection charges and debt retirement charges
are collected by
Brantford Power Inc. and remitted to the IESO and the Ontario Electricity
Financial
Corporation (the OEFC) respectively. The Company retains the distribution
charges reflected
on the customer billings. The distribution charges also incorporate, where
applicable, OEB
approved rate adders or riders that are necessary to dispose of regulatory
assets and liabilities.

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4. Rate Setting - continued

The OEB has the general power to include or exclude costs, revenues, losses or
gains in the
distribution rates of a specific period, resulting in a change in the timing
of accounting
recognition from that which would have applied in an unregulated company. Such
change in
timing gives rise to the recognition of regulatory assets and liabilities. The
Company's

regulatory assets represent certain amounts receivable from customers in the
future and costs
that have been deferred for accounting purposes because it is probable that
they will be
recovered in future rates. In addition, the Company has recorded regulatory
liabilities which
represent amounts of expenses incurred in different periods than would be the
case had the
company been unregulated.
Specific regulatory assets and liabilities are disclosed in note 8.
In the absence of rate regulation, distribution revenue would have been lower
by $3,367,713
(2010 - $1,707,866), cost of power would have been lower by $985,278 (2010 -
$3,753,601),
other income would have been lower by $14,601 (2010 - $16,144), distribution
operations and
maintenance would have been higher by $51,216 (2010 - lower by $46,971),
general
administration would have been higher by $57,877 (2010 - $68,032),
amortization would have
been higher by $315,364 (2010 - $373,781), and interest income would have been
higher by
$48,937 (2010 - $43,600). The net effect, in the absence of rate regulation,
is a pre-tax decrease
in net income for 2011 of $2,772,556 (2010 - increase of $1,678,349).
The Company administers several programs through the Ontario Power Authority
(OPA)
conservation project. The revenues and expenses related to these programs are

not subject to

the regulation of the OEB.

On October 21, 2009 the Company filed an application for 2010 rates on the

basis of the OEB's

third generation Incentive Regulation Mechanism (IRM) policy which

incorporates an OEBapproved

formula that considers inflation and efficiency targets. On April 12, 2010,

the OEB

released its decision. This decision included the repayment of $7,650,132 in

regulatory

liabilities over a two year period. The revised rates were approved with an

effective date of

May 1, 2010.

On October 29, 2010 the Company filed an application for 2011 rates also on

the basis of the

OEB's third generation IRM policy. On March 28, 2011, the OEB released its

decision. This

decision included the repayment of $1,192,282 in regulatory liabilities. The

revised rates were

approved with an effective date of May 1, 2011.

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4. Rate Setting - continued

On November 10, 2011 the Company filed an application for 2012 rates also on

the basis of the

OEB's third generation IRM policy. This application has proposed the repayment

of

$5,841,761 in regulatory liabilities. Included in this total is $2,021,450 in

PILs that resulted

from the OEB PILs proceeding concluded during 2011. The PILs amount was

previously not

reflected in the regulatory liabilities total and will reduce distribution

revenue as it is returned to

the customers. These rates would be effective May 1, 2012. The OEB has not

released its

decision regarding the application.

5. Property, Plant and Equipment

2011 2010

Cost

Accumulated

Amortization

Net Book

Value

Net Book

Value

$ $ $ $

Land 181,961 - 181,961 181,961

Buildings 1,163,732 171,258 992,474 1,015,748

Transformer station 4,507,912 780,833 3,727,079 3,801,417

Distribution stations 74,427 27,544 46,883 49,364

Distribution lines - overhead 28,522,309 9,630,502 18,891,807 18,624,257

Distribution lines - underground 32,009,172 9,026,027 22,983,145 22,225,393

Distribution transformers 17,352,178 5,670,172 11,682,006 11,830,709

Distribution meters 3,988,195 1,014,467 2,973,728 1,984,840

Vehicles 3,033,111 2,142,108 891,003 852,652

Tools and other equipment 800,611 209,499 591,112 640,041

Capital contributions (3,851,573) (684,783) (3,166,790) (3,055,303)

Other utility plant 54,756 - 54,756 51,816

Work in progress 24,008 - 24,008 104,107

87,860,799 27,987,627 59,873,172 58,307,002

6. Intangible Assets

2011 2010

Cost

Accumulated

Amortization

Net Book

Value

Net Book

Value

$ $ $ $

Land rights and easements 5,968 - 5,968 5,968

Stranded meters 5,269,572 2,032,381 3,237,191 4,457,373

Software 435,330 199,178 236,152 84,272

5,710,870 2,231,559 3,479,311 4,547,613

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7. Related Party Transactions

The Company is a wholly owned subsidiary of Brantford Energy Corporation and

Brantford

Energy Corporation is wholly owned by The Corporation of the City of Brantford

(the City).

Brantford Energy Corporation also owns Brantford Hydro Inc. and Brantford

Generation Inc.

The Company obtains certain administrative and management services from the

City and

Brantford Energy Corporation. The Company also provides services to the City,

Brantford
Generations Inc. and Brantford Hydro Inc. These services were made in the
normal course of
business and have been recorded at the exchange amounts.
The Company has entered into a shared services agreement with the City,
whereby the City will
provide administrative, customer care, maintenance and operational services
for the Company.
The exchange amount for these services has been set out in the agreement.
Total charges from
the City under this shared agreement were $8,063,255 (2010 - $8,696,419). As
at December
31, 2011 the balance owing to the City for these services was $1,489,970 (2010
- $1,697,640).
For the year ended December 31, 2011, the Company provided electricity to the
City in the
amount of $5,109,891 (2010 - $5,113,692). The Company also provided other
services to the
City in the amount of $138,410 (2010 - $273,143).
For the year ended December 31, 2011, the Company paid property tax to the
City in the
amount of $16,868 (2010 - $18,887)
The Company obtains management services from Brantford Energy Corporation.
Total charges
for these services were $151,041 (2010 - $124,125). As at December 31, 2011
the balance
owing to Brantford Energy Corporation for these services was $23,312 (2010 -
$11,123).

**Name:** **BRANTFORD POWER INC.**

**BN:** **86585 8773 RC 0001**

**Tax Year Start:** **2011-01-01**

**Tax Year End:** **2011-12-31**

The Company charges pole rental fees to Brantford Hydro Inc. These rental fees

allow fibre

optic cables to be attached to the Company's distribution assets. Total rental

fees for this access

were $42,532 (2010 - $41,102).

For the year ended December 31, 2011, the Company provided electricity to

Brantford

Generation Inc. in the amount of $104,059 (2010 - $48,091). A long term

customer deposit of

$6,955 (2010 - $7,665) has been paid to the Company from Brantford Generation

Inc.

For the year ended December 31, 2011, the Company purchased electricity from

Brantford

Generation Inc. in the amount of $1,641,833 (2010 - $243,060). As of December

31, 2011 the

balance owing to Brantford Generation was $192,299 (2010 - $36,410).

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8. Regulatory Assets and Liabilities

Based on existing regulatory orders or the expectation of future regulatory

orders, the Company

has recorded the following amounts, net of income tax and amortization where

applicable,

which are expected to be recovered from or refunded to customers:

2011 2010

$ $

Regulatory assets

Retail Market Settlement

Retail settlement variance account - Global Adjustment - 527,990

Retailer cost variance accounts 339,637 320,955

Other

Smart meters 3,048,342 3,520,157

Distribution revenue rate change 527,214 388,432

Special purpose charge 19,478 136,836

Other regulatory assets 212,657 152,191

Net regulatory assets 4,147,328 5,046,561

Regulatory liabilities

Retail Market Settlement

Retail settlement variance accounts 4,265,592 5,117,572

Retail settlement variance account - Global Adjustment 205,504 -

Other

Regulatory future income tax liability 509,205 466,778

Regulatory liabilities refundable through approved rate

riders 2,349,523 5,425,441

Net regulatory liabilities 7,329,824 11,009,791

Retail settlement variance accounts

The retail settlement variance accounts represent differences between charges

billed to

customers using the prescribed prices as outlined in the OEB's Retail

Settlement Code and the

actual costs billed to Brantford Power Inc. by the IESO.

Retail cost variance accounts

The retailer cost variance accounts represent differences between charges

billed to retailers

using the prescribed prices as outlined in the OEB's Retail Settlement Code

and the actual costs

paid by Brantford Power Inc. to operate and maintain the systems related to the retail market.

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8. Regulatory Assets and Liabilities - continued

Smart meters

On April 12, 2006, the OEB approved the establishment of regulatory deferral

accounts for

smart meter-related expenditures and approved a monthly rate adder charge of

$0.28 per

metered customer for the Company. Effective May 1, 2009, the OEB increased the

monthly

adder to $1.00 per metered customer. Effective May 1,2010, the OEB increased

the monthly

adder to $2.07 per metered customer. Effective May 1, 2011, the OEB maintained

the monthly

adder at $2.07 per metered customer. In its 2012 application to the OEB, the

Company has

requested the monthly adder be removed.

The Company has recorded a regulatory asset consisting of the net balance of

capital and

operating expenditures for smart meters, less recoveries received from the

rate adder. These

expenditures and recoveries will continue to be reported as regulatory assets

or liabilities until

the Company applies to the OEB to redistribute the amounts to capital or

operations.

Distribution revenue rate change

On February 25, 2009, Brant County Power Inc. (BCPI) filed a motion with the

OEB to review

and vary the Company's 2008 Electricity Distribution Rates. BCPI disputed the rates they were
being charged as well as the date that the Company could bill retroactively. The OEB released
it decision and order related to this motion on August 10, 2010. The decision allowed the
Company to record a regulatory asset consisting of the revenue deficiency between the rates
that were approved during the 2008 cost of service application for the Company's embedded
distributor and the rates that were approved as a result of the BCPI motion.

Special purpose charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge (SPC)
assessment under Section 26.1 of the OEB Act, for the Ministry of Energy and Infrastructure
conservation and renewable energy program costs. The OEB assessed the Company the amount
of $376,534 for its apportioned share of the total provincial amount of the SPC of $53,695,000
in accordance with the rules set out in Ontario Regulation 66/10 (the SPC Regulation). In
accordance with Section 9 of the SPC Regulation, the Company was allowed to recover this
balance. The recovery was completed as at April 30, 2011. As at December 31, 2011, the
balance in the account consists of the Company's assessment less the recoveries received from

customers.

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8. Regulatory Assets and Liabilities - continued

Regulatory future income tax liability

The Company has recorded a regulatory liability account that relates to the

expected future

electricity distribution rate reduction for customers arising from timing

differences in the

recognition of future tax assets.

Regulatory liabilities refundable through approved rate riders

The regulatory liabilities refundable through approved rate riders consists of

balances of

regulatory assets or regulatory liabilities approved for disposition by the

OEB through rate

riders. The amount is subject to carrying charges following the OEB prescribed

methodology

and related rates.

9. Long-Term Debt

2011 2010

$ $

Note payable, bearing interest at 5.87%, repayable to the

City, interest only payable annually - due February, 2016 24,189,168

24,189,168

Royal Bank, non-revolving term facility with interest at

prime repayable in quarterly instalments, due January,

2013 4,361,278 4,715,635

Royal Bank, non-revolving term facility with interest at

prime repayable in quarterly instalments, due November, 2016 683,657 798,292

Ontario Infrastructure and Lands Corporation nonrevolving

term facility with interest at 5.14% repayable

in semi annual instalments due December, 2032 2,212,664 2,268,400

Ontario Infrastructure and Lands Corporation nonrevolving

term facility with interest at 4.95% repayable

in semi annual instalments due December, 2050 4,769,966 4,808,821

Ontario Infrastructure and Lands Corporation construction

advances with interest at 1.75% (2010 - 1.54%) 5,301,704 4,750,364

41,518,437 41,530,680

Less current portion 598,986 1,250,304

40,919,451 40,280,376

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9. Long-Term Debt - continued

The City has an option to extend the maturity date of the promissory note for

successive five

year periods. The City also has the option to convert the principal sum

outstanding into

common shares of the Company at a conversion ratio of $ 100 per common share.

Interest

payable to the City of $1,427,564 (2010 - $1,511,823) was outstanding as at

December 31,

2011.

The Company entered into a swap agreement during 2006 with Royal Bank to hedge

against

exposure to interest rate fluctuations. The agreement represents a notional

principal amount of

$ 5,900,000. Under the terms of the agreement, the company has contracted to pay interest at a

fixed rate of 4.71% while receiving a variable rate equivalent to the one

month Canadian Dollar

Offered Rate to be repriced quarterly.

The Company entered into a second swap agreement during 2006 with Royal Bank

to hedge

against exposure to interest rate fluctuations. The agreement represents a

notional principal

amount of $ 1,200,000. Under the terms of the agreement, the company has

contracted to pay

interest at a fixed rate of 4.97% while receiving a variable rate equivalent

to the one month

Canadian Dollar Offered Rate to be repriced quarterly.

These credit facilities are secured by general security agreement over all

assets of the Company

and an assignment of related fire insurance.

Estimated principal repayment requirements are as follows:

$

2012 598,986

2013 4,230,214

2014 249,710

2015 263,489

2016 24,466,732

Thereafter 11,709,306

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10. Employee Future Benefits

The Company acquired various life insurance, health care related and dental

coverage plan

liabilities for certain retired employees of the former Hydro-Electric
Commission of the City of
Brantford. Travel, dental, vision and semi-private health care coverage is
continued until the
retiree reaches 65 years of age. Life insurance and extended health care
coverage is continued
until the retiree's death. The Company is also obligated to provide post
retirement benefits to
an active employee.

The Company measures the accrued benefit obligation for accounting purposes as
of December
31 of each year. The accrued benefit obligation as at December 31, 2011 and
the expense for
the period ended December 31, 2011 are based on an actuarial valuation done as
at January 1,
2008.

The obligation is unfunded since no assets have been segregated and restricted
to provide the
post-retirement benefits.

Significant Assumptions

The key weighted-average assumptions used by the Company for the measurement
of the
benefit obligation and benefit expense are summarized as follows:

2011 2010

$ $

To determine benefit obligation at end of year

Discount rate 3.25% 4.5%

Assumed long-term rate of return on assets N/A N/A

To determine benefit expense (income) for the year

Discount rate 4.5% 5.0%

Assumed long-term rate of return on assets N/A N/A

Rate of increase in future compensation N/A N/A

Health care cost trend rates at end of year

Initial rate 6.45% 7.30%

Ultimate rate 4.75% 4.75%

Year ultimate rate reached 2013 2013

Sensitivity Analysis Change in

Obligation

Change in

Expense

$ $

Impact of 1% increase in assumed health care trend rate 119,000 13,000

Impact of 1% decrease in assumed health care trend rate (103,000) (11,000)

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10. Employee Future Benefits - continued

2011 2010

$ $

Change in benefit obligation

Benefit obligation at beginning of year 1,810,444 1,713,447

Interest cost on benefit obligation 80,151 85,054

Benefits paid (58,616) (24,737)

Actuarial (gain ) loss on accrued benefit obligation (68,747) 36,680

Benefit obligation at end of year 1,763,232 1,810,444

Change in fair value of assets

Fair value of assets at beginning of year - -

Employer contributions 58,616 24,737

Benefits paid (58,616) (24,737)

Fair value of assets at end of year - -

Reconciliation of funded status to accrued benefit

liability

Deficit of fair value of assets over benefit obligation at end

of year 1,763,232 1,810,444

Unamortized actuarial loss (786,653) (916,705)

Accrued benefit liability at end of year 976,579 893,739

Reconciliation of accrued benefit liability

Accrued benefit liability at beginning of year 893,739 774,365

Benefit expense recognized 141,456 144,111

Benefits paid (58,616) (24,737)

Accrued benefit liability at end of year 976,579 893,739

Annual benefit expense

Interest cost on benefit obligation 80,151 85,054

Actuarial loss 61,305 59,057

Benefit expense recognized 141,456 144,111

Cash payments

Benefit premiums paid 91,633 86,464

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11. Contingencies and Commitments

General Liability Insurance

The Company has obtained general liability and enhanced directors and officers

insurance

coverage from the Municipal Electric Association Reciprocal Insurance Exchange

(The Mearie

Group) expiring January 1, 2013. The Mearie Group is an insurance reciprocal

whereby all

members through the unincorporated group share risks with each other. Members
of the Mearie
Group are assessed a premium deposit at policy execution. Should the group
experience losses
that are in excess of the accumulated premium deposits of its members combined
with reserves
and supplementary insurance, members would be assessed a supplementary or
retro assessment
on a pro-rata basis for the years in which the Company was a member.
As at December 31, 2011, the Company has not been made aware of any additional
assessments. Participation in The Mearie Group covers a three year
underwriting period which
expires on January 1, 2013.
Smart Meter Initiative
The OEB has mandated that the Company is to bill Time of Use Prices using
"Smart Meter"
electricity meters and the Provincial Meter Data Management/Repository
effective July 2011.
The Company was granted an extension of the effective date to December 2011.
The Company has installed approximately 37,134 (2010 - 35,255) Smart Meters as
of the end
of 2011 and anticipates having installed a total of 37,240 Smart Meters upon
completion of its
mass deployment.
12. Subsequent Event
During December 2011, the City announced plans to restructure the Company to
better meet the
Affiliate Relationship Code of the OEB. The major change relates to

approximately 60 staff

members currently employed by the City becoming employees of the Company. The

restructuring will be effective April 1, 2012. At this time, the impact on the

Company's future

financial position and results of operations is not reasonably determinable or

estimable.

13. Share Capital

Authorized

Unlimited number of common shares

2011 2010

$ $

Issued

1,001 common shares 22,437,505 22,437,505

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14. Accumulated Other Comprehensive Loss

2011 2010

$ $

Balance at beginning of year (374,658) (342,478)

Other comprehensive loss, net of tax (143,621) (32,180)

Balance at end of year, net of tax (518,279) (374,658)

15. Pension Plan

The Company participates in the Ontario Municipal Employees Retirement System

(OMERS),

a multi-employer plan, on behalf of its employee. The plan is a contributory

defined benefit

pension plan. Contributions are 7.4% for employee earnings below the year's

maximum

pensionable earnings and 10.7% thereafter. The contribution rates are expected to change to

8.3% for employee earnings below the year's maximum pensionable earnings and

12.8%

thereafter for 2012. During 2011, the Company expensed contributions totaling

$Nil (2010 -

$11,554) made to OMERS in respect of the employer's required contributions to

the plan as its

employee had reached 35 years credited service in the OMERS plan.

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16. Electricity Distribution Service Charges

The company is licensed by the OEB to distribute electricity. As a licensed

distributor, the

Company is responsible for billing customers for electricity generated by

third parties and the

related costs of providing electricity service, such as transmission services

and other services

provided by third parties. The Company is required, pursuant to regulation, to

remit such

amounts to these third parties, irrespective of whether the Company ultimately

collects these

amounts from customers. The Company may file to recover uncollected debt

retirement

charges from OEFC once each year. Otherwise, the Company is unable to recover

uncollected

amounts formerly remitted to these third parties. The Company retains only its

electricity

distribution service charge that is regulated by the OEB.

Electricity distribution service charges comprise:

2011 2010

$ $

Gross customer billings 105,109,712 102,691,543

Less pass through charges billed by the Company

Electricity charges paid through to generators (66,724,020) (62,528,186)

Transmission and miscellaneous charges (10,618,115) (12,192,434)

Market service charges (6,186,857) (6,234,467)

Debt retirement charges (6,422,286) (6,442,494)

Total electricity distribution service charges 15,158,434 15,293,962

17. Statement of Cash Flows

2011 2010

$ $

Changes in non-cash working capital

Accounts receivable 1,109,739 (1,329,770)

Unbilled revenue 358,818 617,437

Inventories 100,514 48,853

Prepaid expenses 39,379 (6,769)

Accounts payable and accrued liabilities (1,465,361) 874,241

Accounts payable to the City of Brantford (207,670) 42,758

Interest payable to the City of Brantford (84,259) -

Due to affiliates 226,604 20,653

Payments in lieu of corporate income taxes (677,733) 266,625

(599,969) 534,028

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18. Amortization

2011 2010

$ $

Amortization of capital assets 3,842,300 3,374,841

Amortization of capital assets charged to distribution

operations and maintenance 271,416 266,240

4,113,716 3,641,081

19. Capital Disclosures

The Company's main objectives when managing capital are to:

" ensure ongoing access to funding to maintain and improve the electricity

distribution system;

" ensure compliance with covenants related to its credit facilities; and

" align its capital structure with the debt to equity structure deemed by the

OEB.

As at December 31, 2011, the Company's definition of capital includes

shareholder's equity and

long-term debt. This definition remains unchanged from prior years. As at

December 31,

2011, shareholder's equity amounts to $34,278,132 (2010 - $33,582,141) and

long-term debt,

amounts to $41,518,437 (2010 - $41,530,680). The Company's capital structure

as at

December 31, 2011 is 55% debt and 45% equity (2010 - 55% debt and 45% equity).

There

have been no changes in the Company's approach to capital management during

the year.

The Company's long-term debt agreements include both financial and non-

financial covenants.

As at December 31, 2011 and as at December 31, 2010, the Company was in

compliance with

all covenants.

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20. Financial Instruments

All financial instruments are initially recorded on the balance sheet at fair
value except for
certain related party transactions. They are subsequently valued either at
fair value or amortized
cost depending on the classification selected by the Company for the financial
instrument. All
financial instruments are classified into one of the five categories: held-for
-trading, loans and
receivables, other liabilities, held-to-maturity investments or available-for-
sale financial assets

Held-for-trading (HFT) financial instruments are financial assets and
financial liabilities
typically acquired with the objective of resale or short-term buyback. The
carrying amount is
recorded at fair value determined using market prices. Interest earned and
gains and losses
incurred are recognized in net income. Cash and cash equivalents and special
deposits are
designated as financial assets held-for-trading and are measured at fair value
with changes
being recorded in net income at each period end. Derivative liabilities are
designated as
financial liabilities held-for-trading and are measured at fair value with
changes being recorded
in other comprehensive income at each period end.

Loans and receivables (LR) are non-derivative financial assets resulting from
the delivery of

cash or other assets by a lender to a borrower in return for a promise to
repay on a specified
date, or on demand, usually with interest. Loans and receivables are measured
at amortized
cost. Accounts receivable and unbilled revenue are classified as loans and
receivables and are
measured at fair value at inception, which due to their short-term nature,
approximates
amortized cost.
Other liabilities (OL) are promises to repay on specified dates or on demand
usually with
interest. Accounts payable and accrued liabilities and accounts payable to the
City of Brantford,
interest payable to the City of Brantford and due to affiliates are classified
as other liabilities
and are measured at fair value at inception, which due to their short-term
nature, approximates
amortized cost. Long-term debt and customer deposits are also classified as
other liabilities.
After their initial fair value measurement, they are measured at amortized
cost using the
effective interest rate method.
Held-to-maturity (HTM) financial assets have fixed or determinable payments
and maturity,
and management's intention and ability are to hold to maturity. These
financial assets are
measured at amortized cost. The Company does not hold any financial assets
under this

classification.

Available-for-sale (AFS) instruments are non-derivative financial assets that

are designated as

available-for-sale or that are not classified as loans and receivables, held-

to-maturity

investments or held-for-trading financial assets. Available-for-sale

instruments are measured at

fair value with unrealized gains and losses recognized in OCI. The Company

does not hold any

financial assets under this classification.

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20. Financial Instruments - continued

Interest Rate Risk

Interest is paid on customer deposits at a market rate reset quarterly as

directed by the Ontario

Energy Board.

Two term facility loans bear interest at floating rates and thus, the carrying

values approximate

fair values. However, the Company has entered into two interest rate swap

transactions,

derivative instruments designated as a cash flow hedges, the effect of which

is to fix the interest

rate on the first $4,369,000 term facility loan at 4.71% and the second

$686,000 term facility

loan at 4.97%. The potential replacement cost to Brantford Power Inc. of the

interest rate

swaps, representing estimated fair value as presented on the balance sheet,

was $713,683 (2010

- $525,435), which was in the favour of Royal Bank. Net unrealized loss in fair value of
$191,491 (2010 - $42,910) is presented in current year Other Comprehensive Loss. The
Company entered into these interest rate swap transactions to fix the interest rates over the long
term and intends to hold these to maturity at which time there should be no replacement cost.

Credit Risk

The Company grants credit to its customers in the normal course of business and monitors their
financial condition and reviews the credit history of new customers. The Company is currently
holding customer deposits on hand in the amount of $2,073,612 (2010 - $2,508,520) which is
reflected on the Balance Sheet. Customer deposits are limited to those allowed under the
OEB's Retail Settlement Code. Allowances of $680,000 (2010 - $608,000) are also maintained
for potential credit losses. The Company's accounts receivable do not reflect the concentrated
risk of default from exposure to large customers. At December 31, 2011, the outstanding
amounts receivable from the largest ten customers represented $1,923,019 or 27% (2010 -
$2,426,830 or 29%) of the total outstanding accounts receivable. Management believes that it
has adequately provided for any exposure to normal customer and retailer

credit risk.

Liquidity Risk

The Company's objective is to have sufficient liquidity to meet its

liabilities when due. The

Company monitors its cash balances and cashflows generated from operations to

meet its

requirements.

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20. Financial Instruments - continued

Prudential Support

Brantford Power Inc. is required, through the Independent Electricity System

Operator (IESO),

to provide security to mitigate the company's risk of default based on its

expected activity in the

electricity market. The IESO could draw on this guarantee if Company fails to

make a payment

required by a default notice issued by the IESO. The maximum potential payment

is the face

value of the bank letter of credit. As at December 31, 2011, the Company

provided prudential

support in the form of a bank letter of credit of $9,375,721 (2010 -

$9,375,721).

Revolving Term Facility

As at December 31, 2011, the Company has been authorized for a revolving term

facility of

$7,000,000 of which NIL had been drawn upon. The facility bears interest at

prime and is

secured by a general security agreement over all assets of the Company and assignment of

related fire insurance.

Fair Value of Other Financial Instruments

a) Establishing fair value

The carrying values of cash and cash equivalents, accounts receivable, special

deposits,

accounts payable and accrued liabilities, accounts payable to the City of

Brantford, interest

payable to the City of Brantford, and due to Brantford Energy Corporation

approximate

their fair values due to the immediate or short-term maturity of these

financial instruments.

Fair values for other financial instruments, detailed below, have been

estimated with

reference to quoted market prices for actual or similar instruments where

available, except

for certain related party transactions.

Customer deposits fair value equals carrying value. Interest is paid on

deposits on a

monthly basis at a market rate, reset quarterly, as directed by the Ontario

Energy Board.

The fixed rate long-term debt facility, maturing December 2032, funded by the

Ontario

Infrastructure and Lands Corporation (OILC) has an estimated fair value of

$2,492,700

(carrying value - $2,212,664). The fair value was determined using the present

value of the

cash flows using the quoted OILC market rate for the debt at December 31, 2011, of 3.78%

per annum, (actual rate - 5.14% per annum). The loan is classified as an Other

Liability

(OL) with no resulting adjustment to carrying value.

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20. Financial Instruments - continued

The fixed rate long-term debt facility, maturing December 2050, funded by the

OILC has

an estimated fair value of $5,442,200 (carrying value - $4,769,966). The fair

value was

determined using the present value of the cash flows using the quoted OILC

market rate for

the debt at December 31, 2011, of 4.00% per annum, (actual rate - 4.95% per

annum). The

loan is classified as an Other Liability (OL) with no resulting adjustment to

carrying value.

The promissory note payable to the Corporation of the City of Brantford,

classified as an

OL, is valued at face value. It is not practicable within constraints of

timeliness or cost to

measure reliably the fair value of this financial liability that originated in

a related party

transaction.

Construction advances funded by the OILC, classified as OL are valued at face

value.

Upon completion of construction the term of the loan will be 15 years.

The fair value of derivative instruments is calculated using pricing models

that incorporate

current market prices and the contractual prices of the underlying
instruments, the time
value of money and yield curves.

b) Fair value hierarchy

Financial instruments recorded at fair value on the Balance Sheet are
classified using a fair
value hierarchy that reflects the significance of the inputs used in making
the
measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for
identical
assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices
included in Level 1
that are observable for the asset or liability, either directly (ie as prices)
or indirectly (ie
derived from prices);

Level 3 - valuation techniques using inputs for the asset or liability that
are not based on
observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever
such inputs
exist. A financial instrument is classified to the lowest level of the
hierarchy for which a
significant input has been considered in measuring fair value.

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20. Financial Instruments - continued

The following table presents the financial instruments recorded at fair value in the Balance

Sheet, classified using the fair value hierarchy described above:

Level 1 Level 2 Level 3

Total financial

assets and

liabilities at fair

value

$ $ $ $

Financial Assets

Cash and cash equivalents 9,200,282 - - 9,200,282

Special deposits 2,073,612 - - 2,073,612

Total financial assets 11,273,894 - - 11,273,894

Financial liabilities

Customer deposits 2,073,612 - - 2,073,612

Total financial liabilities 2,073,612 - - 2,073,612

During the year, there has been no transfer of amounts between Level 1 and

Level 2 and no

financial assets or liabilities have been identified as Level 3.

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21. Payments in Lieu of Corporate Income Taxes

The Company's income tax expense for the year ended December 31, 2011 consists

of the

following:

Temporary differences which give rise to future income tax assets and

liabilities are as follows:

2011 2010

$ $

Regulatory assets 643,641 1,658,807

Cumulative eligible capital 156,910 170,190

Allowance for doubtful accounts 178,500 171,760

Property, plant and equipment 1,063,135 1,047,872

Employee future benefits 244,390 224,150

Unrealized losses on derivative liabilities 171,620 123,750

Future income tax assets 2,458,196 3,396,529

Distributed as such:

Future payments in lieu of corporate income tax asset

Current 178,500 171,760

Non-current 2,279,696 3,224,769

2,458,196 3,396,529

The impact of differences between the Company's reported payments in lieu of

corporate

income taxes and the expense that would otherwise result from the application

of statutory rates

is as follows:

2011 2010

$ $

Income tax expense at the combined basis federal and

provincial statutory tax rate 1,003,091 1,192,799

Net change in regulatory assets 8,794 1,161,325

Capital cost allowance in excess of amortization (140,633) (779,373)

Net change in tax reserves (95,268) 47,254

Tax effect of gain on sale of fixed assets (6,373) (15,831)

Tax effect of expenses that are not deductible for income

tax purposes 423 754

770,034 1,606,928

22. Comparative Figures

**Name:** **BRANTFORD POWER INC.**

**BN:** **86585 8773 RC 0001**

**Tax Year Start:** **2011-01-01**

**Tax Year End:** **2011-12-31**

Certain prior year figures have been reclassified to conform with the current year's presentation.

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Canada Revenue Agency / Agence du revenu du Canada

# NET INCOME (LOSS) FOR INCOME TAX PURPOSES

## SCHEDULE 1

| Corporation's name | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125 ........ 2,289,612 A

**Add:**

| | Line | Amount | Total |
|---|---|---|---|
| Provision for income taxes – current | 101 | -258,596 | |
| Provision for income taxes – deferred | 102 | 1,028,630 | |
| Amortization of tangible assets | 104 | 4,113,716 | |
| Charitable donations and gifts from Schedule 2 | 112 | 1,450 | |
| Non-deductible meals and entertainment expenses | 121 | 1,834 | |
| Other reserves on lines 270 and 275 from Schedule 13 | 125 | 2,508,520 | |
| Reserves from financial statements – balance at the end of the year | 126 | 3,651,679 | |
| Subtotal of additions | | 11,047,233 | 11,047,233 |

**Other additions:**

**Miscellaneous other additions:**

| | | | Line | Amount | Total |
|---|---|---|---|---|---|
| 600 | CY cumulative adjusted regulatory asset | | 290 | 8,031,724 | |
| 603 | Additional loss on FA netted in IS | 3,275 | | | |
| | Total | 3,275 | 293 | 3,275 | |
| 604 | | | | | |
| | Total | | 294 | | |
| | Subtotal of other additions | | 199 | 8,034,999 | 8,034,999 |
| | **Total additions** | | 500 | 19,082,232 | 19,082,232 |

**Deduct:**

| | Line | Amount | Total |
|---|---|---|---|
| Gain on disposal of assets per financial statements | 401 | 19,025 | |
| Capital cost allowance from Schedule 8 | 403 | 4,172,471 | |
| Cumulative eligible capital deduction from Schedule 10 | 405 | 47,014 | |
| Other reserves on line 280 from Schedule 13 | 413 | 2,073,612 | |
| Reserves from financial statements – balance at the beginning of the year | 414 | 3,934,035 | |
| Subtotal of deductions | | 10,246,157 | 10,246,157 |

**Other deductions:**

**Miscellaneous other deductions:**

| | | | Line | Amount | Total |
|---|---|---|---|---|---|
| 700 | Capital tax recorded per books | | 390 | 1,318 | |
| 701 | PY cumulative adjusted regulatory assets | | 391 | 11,163,068 | |
| 703 | previously capitalized overhead | 1,162,134 | | | |
| | Total | 1,162,134 | 393 | 1,162,134 | |
| 704 | | | | | |
| | Total | | 394 | | |
| | Subtotal of other deductions | | 499 | 12,326,520 | 12,326,520 |
| | **Total deductions** | | 510 | 22,572,677 | 22,572,677 |

**Net income (loss) for income tax purposes** – enter on line 300 of the T2 return ........ -1,200,833

# Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

| Description | Amount | |
|---|---|---|
| Regulatory Asset per F/S | 3,182,496 | 00 |
| PPVA @ 9/30/01 | -898,000 | 00 |
| Transition Costs @ 9/30/01 | 364,437 | 00 |
| Regulatory Assets capitalized | 292,547 | 00 |
| Global Adjustment reversal | -196,966 | 00 |
| Smart Meter Capital - not in use | 5,287,210 | 00 |
| | | |
| **Total** | 8,031,724 | 00 |

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 2**

# CHARITABLE DONATIONS AND GIFTS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

## Part 1 – Charitable donations

| Charity/Recipient | Amount ($100 or more only) |
|---|---|
| Wilfred Laurier University | 1,000 |
| Subtotal | 1,000 |
| **Add:** Total donations of less than $100 each | 450 |
| Total donations in current tax year | 1,450 |

| | Line | Federal | Québec | Alberta |
|---|---|---|---|---|
| Charitable donations at the end of the previous tax year | | | | |
| **Deduct:** Charitable donations expired after five tax years* | 239 | | | |
| Charitable donations at the beginning of the tax year | 240 | | | |
| **Add:** | | | | |
| Charitable donations transferred on an amalgamation or the wind-up of a subsidiary | 250 | | | |
| Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) 210: 1,450 | | | | |
| Subtotal (line 250 **plus** line 210) | | 1,450 | 1,450 | 1,450 |
| **Deduct:** Adjustment for an acquisition of control (for donations made after March 22, 2004) | 255 | | | |
| Total charitable donations available | | 1,450 A | 1,450 | 1,450 |
| **Deduct:** Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return) | 260 | | | |
| Charitable donations closing balance | 280 | 1,450 | 1,450 | 1,450 |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amounts carried forward – Charitable donations

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2010-12-31 | | | |
| 2nd prior year | 2009-12-31 | | | |
| 3rd prior year | 2008-12-31 | | | |
| 4th prior year | 2007-12-31 | | | |
| 5th prior year | 2006-12-31 | | | |
| 6th prior year* | 2005-12-31 | | | |
| 7th prior year | 2004-12-31 | | | |
| 8th prior year | 2003-12-31 | | | |
| 9th prior year | 2002-12-31 | | | |
| 10th prior year | 2001-12-31 | | | |
| 11th prior year | 2000-12-31 | | | |
| 12th prior year | 1999-12-31 | | | |
| 13th prior year | 1998-12-31 | | | |
| 14th prior year | 1997-12-31 | | | |
| 15th prior year | 1996-12-31 | | | |
| 16th prior year | 1995-12-31 | | | |
| 17th prior year | 1994-12-31 | | | |
| 18th prior year | 1993-12-31 | | | |
| 19th prior year | 1992-12-31 | | | |
| 20th prior year | 1991-12-31 | | | |
| 21st prior year* | 1990-12-31 | | | |
| **Total** (to line A) | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % ______ B

Taxable capital gains arising in respect of gifts of capital property included in Part 1** **225** ______ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) **227** ______ D

The amount of the recapture of capital cost allowance in respect of charitable gifts **230** ______

Proceeds of disposition, less outlays and expenses** ______ E

Capital cost** ______ F

Amount E or F, whichever is less **235** ______

Amount on line 230 or 235, whichever is less ______ G

Subtotal (**add** amounts C, D, and G) ______ H

Amount H **multiplied** by 25 % ______ I

Subtotal (amount B **plus** amount I) ______ J

**Maximum allowable deduction for charitable donations** (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ______ K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

## Part 3 – Gifts to Canada, a province, or a territory

| | Line | Amount | Amount |
|---|---|---|---|
| Gifts to Canada, a province, or a territory at the end of the previous tax year | | | |
| **Deduct:** Gifts to Canada, a province, or a territory expired after five tax years | 339 | | |
| Gifts to Canada, a province, or a territory at the beginning of the tax year | 340 | | ▶ |
| **Add:** Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary | 350 | | |
| Total current-year gifts made to Canada, a province, or a territory* | 310 | | |
| Subtotal (line 350 **plus** line 310) | | | |
| **Deduct:** Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 355 | | |
| Total gifts to Canada, a province, or a territory available | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 312 of the T2 return). | 360 | | |
| Gifts to Canada, a province, or a territory closing balance | 380 | | |

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

## Part 4 – Gifts of certified cultural property

| | Line | Federal | Québec | Alberta |
|---|---|---|---|---|
| Gifts of certified cultural property at the end of the previous tax year | | | | |
| **Deduct:** Gifts of certified cultural property expired after five tax years* | 439 | | | |
| Gifts of certified cultural property at the beginning of the tax year | 440 | | | |
| **Add:** Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary | 450 | | | |
| Total current-year gifts of certified cultural property | 410 | | | |
| Subtotal (line 450 **plus** line 410) | | | | |
| **Deduct:** Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 455 | | | |
| Total gifts of certified cultural property available | | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 313 of the T2 return) | 460 | | | |
| Gifts of certified cultural property closing balance | 480 | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amount carried forward – Gifts of certified cultural property

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2010-12-31 | | | |
| 2nd prior year | 2009-12-31 | | | |
| 3rd prior year | 2008-12-31 | | | |
| 4th prior year | 2007-12-31 | | | |
| 5th prior year | 2006-12-31 | | | |
| 6th prior year* | 2005-12-31 | | | |
| 7th prior year | 2004-12-31 | | | |
| 8th prior year | 2003-12-31 | | | |
| 9th prior year | 2002-12-31 | | | |
| 10th prior year | 2001-12-31 | | | |
| 11th prior year | 2000-12-31 | | | |
| 12th prior year | 1999-12-31 | | | |
| 13th prior year | 1998-12-31 | | | |
| 14th prior year | 1997-12-31 | | | |
| 15th prior year | 1996-12-31 | | | |
| 16th prior year | 1995-12-31 | | | |
| 17th prior year | 1994-12-31 | | | |
| 18th prior year | 1993-12-31 | | | |
| 19th prior year | 1992-12-31 | | | |
| 20th prior year | 1991-12-31 | | | |
| 21st prior year* | 1990-12-31 | | | |
| **Total** | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 5 – Gifts of certified ecologically sensitive land

| | | Federal | Québec | Alberta |
|---|---|---|---|---|
| Gifts of certified ecologically sensitive land at the end of the previous tax year | | | | |
| **Deduct:** Gifts of certified ecologically sensitive land expired after five tax years* | 539 | | | |
| Gifts of certified ecologically sensitive land at the beginning of the tax year | 540 | | | |
| **Add:** Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary | 550 | | | |
| Total current-year gifts of certified ecologically sensitive land | 510 | | | |
| Subtotal (line 550 **plus** line 510) | | | | |
| **Deduct:** Adjustment for an acquisition of control (for gifts made after March 22, 2004) | 555 | | | |
| Total gifts of certified ecologically sensitive land available | | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 314 of the T2 return) | 560 | | | |
| Gifts of certified ecologically sensitive land closing balance | 580 | | | |

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

## Amounts carried forward – Gifts of certified ecologically sensitive land

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2010-12-31 | | | |
| 2nd prior year | 2009-12-31 | | | |
| 3rd prior year | 2008-12-31 | | | |
| 4th prior year | 2007-12-31 | | | |
| 5th prior year | 2006-12-31 | | | |
| 6th prior year* | 2005-12-31 | | | |
| 7th prior year | 2004-12-31 | | | |
| 8th prior year | 2003-12-31 | | | |
| 9th prior year | 2002-12-31 | | | |
| 10th prior year | 2001-12-31 | | | |
| 11th prior year | 2000-12-31 | | | |
| 12th prior year | 1999-12-31 | | | |
| 13th prior year | 1998-12-31 | | | |
| 14th prior year | 1997-12-31 | | | |
| 15th prior year | 1996-12-31 | | | |
| 16th prior year | 1995-12-31 | | | |
| 17th prior year | 1994-12-31 | | | |
| 18th prior year | 1993-12-31 | | | |
| 19th prior year | 1992-12-31 | | | |
| 20th prior year | 1991-12-31 | | | |
| 21st prior year* | 1990-12-31 | | | |
| **Total** | | | | |

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

## Part 6 – Additional deduction for gifts of medicine

| | Code | Federal | Québec | Alberta |
|---|---|---|---|---|
| Additional deduction for gifts of medicine at the end of the previous tax year | | | | |
| **Deduct:** Additional deduction for gifts of medicine expired after five tax years | 639 | | | |
| Additional deduction for gifts of medicine at the beginning of the tax year | 640 | | | |
| **Add:** Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary | 650 | | | |

Additional deduction for gifts of medicine for the current year:

| | Code | Federal | Québec | Alberta |
|---|---|---|---|---|
| Proceeds of disposition | 602 | 1 | 1 | 1 |
| Cost of gifts of medicine | 601 | 2 | 2 | 2 |
| Subtotal (line 1 **minus** line 2) | | 3 | 3 | 3 |
| Line 3 **multiplied** by 50 % | | 4 | 4 | 4 |
| Eligible amount of gifts | 600 | 5 | 5 | 5 |

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

**A** is the **lesser** of line 2 and line 4

**B** is the eligible amount of gifts (line 600)

**C** is the proceeds of disposition (line 602)

| | Code | Federal | Québec | Alberta |
|---|---|---|---|---|
| Subtotal (line 650 **plus** line 610) | | | | |
| **Deduct:** Adjustment for an acquisition of control | 655 | | | |
| Total additional deduction for gifts of medicine available | | | | |
| **Deduct:** Amount applied against taxable income (enter this amount on line 315 of the T2 return) | 660 | | | |
| Additional deduction for gifts of medicine closing balance | 680 | | | |

## Amounts carried forward – Additional deduction for gifts of medicine

| Year of origin: | | Federal | Québec | Alberta |
|---|---|---|---|---|
| 1st prior year | 2010-12-31 | | | |
| 2nd prior year | 2009-12-31 | | | |
| 3rd prior year | 2008-12-31 | | | |
| 4th prior year | 2007-12-31 | | | |
| 5th prior year | 2006-12-31 | | | |
| 6th prior year* | 2005-12-31 | | | |
| **Total** | | | | |

***** These donations expired in the current year.

## Québec – Gifts of musical instruments

| | | |
|---|---|---|
| Gifts of musical instruments at the end of the previous tax year | | A |
| **Deduct:** Gifts of musical instruments expired after twenty tax years | | B |
| Gifts of musical instruments at the beginning of the tax year | | C |
| **Add:** | | |
| Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary | | D |
| Total current-year gifts of musical instruments | | E |
| Subtotal (line D **plus** line E) | | F |
| **Deduct:** Adjustment for an acquisition of control | | G |
| Total gifts of musical instruments available | | H |
| **Deduct:** Amount applied against taxable income | | I |
| Gifts of musical instruments closing balance | | J |

## Amounts carried forward – Gifts of musical instruments

| Year of origin: | | Québec |
|---|---|---|
| 1st prior year | 2010-12-31 | |
| 2nd prior year | 2009-12-31 | |
| 3rd prior year | 2008-12-31 | |
| 4th prior year | 2007-12-31 | |
| 5th prior year | 2006-12-31 | |
| 6th prior year* | 2005-12-31 | |
| 7th prior year | 2004-12-31 | |
| 8th prior year | 2003-12-31 | |
| 9th prior year | 2002-12-31 | |
| 10th prior year | 2001-12-31 | |
| 11th prior year | 2000-12-31 | |
| 12th prior year | 1999-12-31 | |
| 13th prior year | 1998-12-31 | |
| 14th prior year | 1997-12-31 | |
| 15th prior year | 1996-12-31 | |
| 16th prior year | 1995-12-31 | |
| 17th prior year | 1994-12-31 | |
| 18th prior year | 1993-12-31 | |
| 19th prior year | 1992-12-31 | |
| 20th prior year | 1991-12-31 | |
| 21st prior year* | 1990-12-31 | |
| **Total** | | |

* These gifts expired in the current year.

Canada Revenue Agency / Agence du revenu du Canada

# DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

**SCHEDULE 3**

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

## Part 1 – Dividends received in the tax year

**Do not include dividends received from foreign non-affiliates.**

| | | Complete if payer corporation is connected | | | |
|---|---|---|---|---|---|
| Name of payer corporation (from which the corporation received the dividend) 200 | A | **B** Enter 1 if payer corporation is connected 205 | **C** Business Number of connected corporation 210 | **D** Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220 | **E** Non-taxable dividend under section 83 230 |
| | | | | | |
| | | | | **Total** (enter on line 402 of Schedule 1) | |

**Note**: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

| | | | Complete if payer corporation is connected | | |
|---|---|---|---|---|---|
| **F** Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240 | **F1** Eligible dividends (included in column F) | **F2** | **G** Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 | **H** Dividend refund of the connected payer corporation (for tax year in column D)** 260 | **I** Part IV tax before deductions F x 1 / 3 *** 270 |
| | | | | | |
| | | | | | J |

**Total** (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

## Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .

**Deduct:**

Part IV.I tax payable on dividends subject to Part IV tax . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **320**

Subtotal

**Deduct:**

Current-year non-capital loss claimed to reduce Part IV tax . . . . . . . . . . . . . . . . . **330**

Non-capital losses from previous years claimed to reduce Part IV tax . . . . . . . . . . **335**

Current-year farm loss claimed to reduce Part IV tax . . . . . . . . . . . . . . . . . . . . . **340**

Farm losses from previous years claimed to reduce Part IV tax . . . . . . . . . . . . . . **345**

Total losses applied against Part IV tax x 1 / 3 =

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **360**

## Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

| | A | B | C | D | D1 |
|---|---|---|---|---|---|
| | Name of connected recipient corporation **400** | Business Number **410** | Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD **420** | Taxable dividends paid to connected corporations **430** | Eligible dividends (included in column D) |
| 1 | Brantford Energy Corporation | 87504 1329 RC0001 | 2011-12-31 | 1,450,000 | |

**Note**

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

**Total** 1,450,000

Total taxable dividends paid in the tax year to other than connected corporations . . . . . . . . . . . . . . . . . . . . . . . . . . . **450**

Eligible dividends (included in line 450) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **460** 1,450,000

## Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) . . . . . . . . . . . . . . . . . . . . 1,450,000

Other dividends paid in the tax year (total of 510 to 540) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .

Total dividends paid in the tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** 1,450,000

**Deduct:**

Dividends paid out of capital dividend account . . . . . . . . . . . . . . . . . . . . . . . . . . **510**

Capital gains dividends . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520**

Dividends paid on shares described in subsection 129(1.2) . . . . . . . . . . . . . . . . . **530**

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **540**

Subtotal ►

Total taxable dividends paid in the tax year that qualify for a dividend refund . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1,450,000

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**SCHEDULE 4**

# CORPORATION LOSS CONTINUITY AND APPLICATION

| Name of corporation | Business number | Tax year-end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time. Also, no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

## Part 1 – Non-capital losses

**Determination of current-year non-capital loss**

| | | | | |
|---|---|---|---|---|
| Net income (loss) for income tax purposes | | | -1,200,833 | A |
| **Deduct:** (increase a loss) | | | | |
| Net capital losses deducted in the year (enter as a positive amount) | | a | | |
| Taxable dividends deductible under sections 112, 113(1), or subsection 138(6) | | b | | |
| Amount of Part VI.1 tax deductible | | c | | |
| Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2) | | d | | |
| Subtotal (total of amounts a to d) | | ▶ | | B |
| Subtotal (amount A **minus** amount B; if positive, enter "0") | | | -1,200,833 | C |
| **Deduct:** (increase a loss) | | | | |
| Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions | | | | D |
| Subtotal (amount C **minus** amount D) | | | -1,200,833 | E |
| **Add:** (decrease a loss) | | | | |
| Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss. Enter amount F on line 310) | | | | F |
| Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0"; if negative, enter amount G on line 110 as a positive) | | | -1,200,833 | G |

**Continuity of non-capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Non-capital loss at the end of the previous tax year | | | e | | |
| **Deduct:** Non-capital loss expired* | 100 | | f | | |
| Non-capital losses at the beginning of the tax year (amount e **minus** amount f) | 102 | | ▶ | | H |
| **Add:** | | | | | |
| Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation | 105 | | g | | |
| Current-year non-capital loss (amount G above) | 110 | 1,200,833 | h | | |
| Subtotal (amount g **plus** amount h) | | 1,200,833 | ▶ | 1,200,833 | I |
| Subtotal (amount H **plus** amount I) | | | | 1,200,833 | J |

* A non-capital loss expires as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

## Part 1 – Non-capital losses (continued)

Amount J from page 1 1,200,833

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Other adjustments (includes adjustments for an acquisition of control) | 150 | | i j | | |
| Section 80 – Adjustments for forgiven amounts | 140 | | j.1 | | |
| Subsection 111(10) – Adjustments for fuel tax rebate | | | | | |
| Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 Return) | 130 | | k | | |
| Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 330 and 335 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively) | 135 | | l | | |
| Subtotal (total of amounts i to l) | | | ▶ | | K |
| Non-capital losses before any request for a carryback (amount J **minus** amount K) | | | | 1,200,833 | L |

**Deduct** – **Request to carry back non-capital loss to:**

| | | | | | |
|---|---|---|---|---|---|
| First previous tax year to reduce taxable income | 901 | | m | | |
| Second previous tax year to reduce taxable income | 902 | | n | | |
| Third previous tax year to reduce taxable income | 903 | 1,207,383 | o | | |
| First previous tax year to reduce taxable dividends subject to Part IV tax | 911 | | p | | |
| Second previous tax year to reduce taxable dividends subject to Part IV tax | 912 | | q | | |
| Third previous tax year to reduce taxable dividends subject to Part IV tax | 913 | | r | | |
| Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r) | | 1,207,383 | ▶ | 1,207,383 | M |
| Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M) | 180 | | | | N |

## Part 2 – Capital losses

**Continuity of capital losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Capital losses at the end of the previous tax year | 200 | | a | | |
| Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation | 205 | | b | | |
| Subtotal (amount a **plus** amount b) | | | ▶ | | A |
| **Deduct:** | | | | | |
| Other adjustments (includes adjustments for an acquisition of control) | 250 | | c | | |
| Section 80 – Adjustments for forgiven amounts | 240 | | d | | |
| Subtotal (amount c **plus** amount d) | | | ▶ | | B |
| Subtotal (amount A **minus** amount B) | | | | | C |
| **Add:** Current-year capital loss (from the calculation on Schedule 6) | 210 | | | 3,275 | D |
| Unused non-capital losses that expired in the tax year* | | | e | | |
| Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year** | | | f | | |
| Enter amount e or f, whichever is less | 215 | | | | |
| ABILs expired as non-capital loss: line 215 **divided** by 0.500000 | 220 | | | | E |
| Subtotal (total of amounts C to E) | | | | 3,275 | F |

**Note**

If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

## Part 2 – Capital losses (continued)

| | | | |
|---|---|---|---|
| Amount F from page 2 | | 3,275 | |
| **Deduct:** Capital losses from previous tax years applied against the current-year net capital gain (see Note 1) | 225 | | G |
| Capital losses before any request for a carryback (amount F **minus** amount G) | | 3,275 | H |

**Deduct** – **Request to carry back capital loss to** (see Note 2):

| | Capital gain (100%) | | Amount carried back (100%) | | | |
|---|---|---|---|---|---|---|
| First previous tax year | 7,387 | 951 | 3,275 | g | | |
| Second previous tax year | 4,925 | 952 | | h | | |
| Third previous tax year | 4,925 | 953 | | i | | |
| Subtotal (total of amounts g to i) | | | 3,275 | ▶ | 3,275 | I |
| Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I) | | | | 280 | | J |

**Note 1**

To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

**Note 2**

On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

## Part 3 – Farm losses

**Continuity of farm losses and request for a carryback**

| | | | | | |
|---|---|---|---|---|---|
| Farm losses at the end of the previous tax year | | | a | | |
| **Deduct:** Farm loss expired* | 300 | | b | | |
| Farm losses at the beginning of the tax year (amount a **minus** amount b) | 302 | | ▶ | | A |
| **Add:** | | | | | |
| Farm losses transferred on the amalgamation or the windup of a subsidiary corporation | 305 | | c | | |
| Current-year farm loss | 310 | | d | | |
| Subtotal (amount c **plus** amount d) | | | ▶ | | B |
| Subtotal (amount A **plus** amount B) | | | | | C |
| **Deduct:** | | | | | |
| Other adjustments (includes adjustments for an acquisition of control) | 350 | | e | | |
| Section 80 – Adjustments for forgiven amounts | 340 | | f | | |
| Farm losses of previous tax years applied in the current tax year (enter on line 334 of the T2 Return) | 330 | | g | | |
| Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 340 and 345 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively) | 335 | | h | | |
| Subtotal (total of amounts e to h) | | | ▶ | | D |
| Farm losses before any request for a carryback (amount C **minus** amount D) | | | | | E |
| **Deduct** – **Request to carry back farm loss to:** | | | | | |
| First previous tax year to reduce taxable income | 921 | | i | | |
| Second previous tax year to reduce taxable income | 922 | | j | | |
| Third previous tax year to reduce taxable income | 923 | | k | | |
| First previous tax year to reduce taxable dividends subject to Part IV tax | 931 | | l | | |
| Second previous tax year to reduce taxable dividends subject to Part IV tax | 932 | | m | | |
| Third previous tax year to reduce taxable dividends subject to Part IV tax | 933 | | n | | |
| Subtotal (total of amounts i to n) | | | ▶ | | F |
| Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) | | | 380 | | G |

* A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

## Part 4 – Restricted farm losses

**Current-year restricted farm loss**

| | | | |
|---|---|---|---|
| Total losses for the year from farming business | | **485** | A |
| **Minus** the deductible farm loss: | | | |
| (amount A above – $2,500) **divided** by 2 = | a | | |
| Amount a or $ 6,250 , whichever is less | | | b |
| | 2,500 | | c |
| Subtotal (amount b **plus** amount c) | 2,500 | 2,500 | B |
| Current-year restricted farm loss (amount A **minus** amount B; enter amount C on line 410) | | | C |

**Continuity of restricted farm losses and request for a carryback**

| | Line | | |
|---|---|---|---|
| Restricted farm losses at the end of the previous tax year | | | d |
| **Deduct:** Restricted farm loss expired* | 400 | | e |
| Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) | 402 | | D |
| **Add:** | | | |
| Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation | 405 | | f |
| Current-year restricted farm loss (enter on line 233 of Schedule 1) | 410 | | g |
| Subtotal (amount f **plus** amount g) | | | E |
| Subtotal (amount D **plus** amount E) | | | F |
| **Deduct:** | | | |
| Restricted farm losses from previous tax years applied against current farming income (enter on line 333 of the T2 Return) | 430 | | h |
| Section 80 – Adjustments for forgiven amounts | 440 | | i |
| Other adjustments | 450 | | j |
| Subtotal (total of amounts h to j) | | | G |
| Restricted farm losses before any request for a carryback (amount F **minus** amount G) | | | H |
| **Deduct** – **Request to carry back restricted farm loss to:** | | | |
| First previous tax year to reduce farming income | 941 | | k |
| Second previous tax year to reduce farming income | 942 | | l |
| Third previous tax year to reduce farming income | 943 | | m |
| Subtotal (total of amounts k to m) | | | I |
| Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) | 480 | | J |

**Note**

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

## Part 5 – Listed personal property losses

**Continuité des pertes sur des biens meubles déterminés et demande de report rétrospectif**

| | | | | | |
|---|---|---|---|---|---|
| Listed personal property losses at the end of the previous tax year | | | a | | |
| **Deduct:** Listed personal property loss expired after seven tax years | 500 | | b | | |
| Listed personal property losses at the beginning of the tax year (amount a **minus** amount b) | 502 | | ▶ | | A |
| **Add:** Current-year listed personal property loss (from Schedule 6) | | | 510 | | B |
| Subtotal (amount A **plus** amount B) | | | | | C |

**Deduct:**

| | | | | | |
|---|---|---|---|---|---|
| Previous year personal property losses applied in the current tax year against listed personal property gains (enter on line 655 of Schedule 6) | 530 | | c | | |
| Other adjustments | 550 | | d | | |
| Subtotal (amount c **plus** amount d) | | | ▶ | | D |
| Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D) | | | | | E |

**Deduct – Request to carry back listed personal property loss to:**

| | | | | | |
|---|---|---|---|---|---|
| First previous tax year to reduce listed personal property gains | 961 | | e | | |
| Second previous tax year to reduce listed personal property gains | 962 | | f | | |
| Third previous tax year to reduce listed personal property gains | 963 | | g | | |
| Subtotal (total of amounts e to g) | | | ▶ | | F |
| Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F) | | | 580 | | G |

## Part 7 – Limited partnership losses

**Current-year limited partnership losses**

| 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|
| Partnership identifier 600 | Tax year ending YYYY/MM/DD 602 | Corporation's share of limited partnership loss 604 | Corporation's at-risk amount 606 | Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608 | Column 4 **minus** column 5 (if negative, enter "0") | Current-year limited partnership losses (column 3 **minus** 6) 620 |
| | | | | | | |
| | | | | | **Total** (enter this amount on line 222 of Schedule 1) | |

**Limited partnership losses from previous tax years that may be applied in the current year**

| 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|
| Partnership identifier 630 | Tax year ending YYYY/MM/DD 632 | Limited partnership losses at the end of the previous tax year 634 | Corporation's at-risk amount 636 | Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638 | Column 4 **minus** column 5 (if negative, enter "0") | Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650 |
| | | | | | | |

**Continuity of limited partnership losses that can be carried forward to future tax years**

| 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|
| Partnership identifier 660 | Limited partnership losses at the end of the previous tax year 662 | Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664 | Current-year limited partnership losses (from column 620) 670 | Limited partnership losses applied in the current year (cannot be more than column 650) 675 | Current year limited partnership losses closing balance to be carried forward to future years (662 + 664 + 670 – 675) 680 |
| | | | | | |
| | | | **Total** (enter this amount on line 335 of the T2 return) | | |

**Note**

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

## Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 190 Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

**Note**

This election is only applicable for wind-ups under 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

# Attached Schedule with Total

Third previous tax year to reduce taxable income

Title Third previous tax year to reduce taxable income

| Description | Amount |
|---|---|
| before amendment | 353,373 00 |
| additional losses available to carry back after 2011 amendment | 854,010 00 |
| | |
| **Total** | 1,207,383 00 |

# Non-Capital Loss Continuity Workchart

## Part 6 – Analysis of balance of losses by year of origin

### Non-capital losses – losses that can be carried forward over 20 years

| Year of origin | Balance at beginning of year | Loss incurred in current year | Adjustments and transfers | Loss carried back Parts I & IV | Applied to reduce Taxable income | Applied to reduce Part IV tax | Balance at end of year |
|---|---|---|---|---|---|---|---|
| Current | N/A | 1,200,833 | | 1,200,833 | N/A | | |
| 1st preceding taxation year 2010-12-31 | | N/A | | N/A | | | |
| 2nd preceding taxation year 2009-12-31 | | N/A | | N/A | | | |
| 3rd preceding taxation year 2008-12-31 | | N/A | | N/A | | | |
| 4th preceding taxation year 2007-12-31 | | N/A | | N/A | | | |
| 5th preceding taxation year 2006-12-31 | | N/A | | N/A | | | |
| 6th preceding taxation year 2005-12-31 | | N/A | | N/A | | | |
| 7th preceding taxation year 2004-12-31 | | N/A | | N/A | | | |
| 8th preceding taxation year 2003-12-31 | | N/A | | N/A | | | |
| 9th preceding taxation year 2002-12-31 | | N/A | | N/A | | | |
| 10th preceding taxation year 2001-12-31 | | N/A | | N/A | | | |
| 11th preceding taxation year 2000-12-31 | | N/A | | N/A | | | |
| 12th preceding taxation year 1999-12-31 | | N/A | | N/A | | | |
| 13th preceding taxation year 1998-12-31 | | N/A | | N/A | | | |
| 14th preceding taxation year 1997-12-31 | | N/A | | N/A | | | |
| 15th preceding taxation year 1996-12-31 | | N/A | | N/A | | | |
| 16th preceding taxation year 1995-12-31 | | N/A | | N/A | | | |
| 17th preceding taxation year 1994-12-31 | | N/A | | N/A | | | |
| 18th preceding taxation year 1993-12-31 | | N/A | | N/A | | | |
| 19th preceding taxation year 1992-12-31 | | N/A | | N/A | | | |
| 20th preceding taxation year 1991-12-31 | | N/A | | N/A | | | * |
| **Total** | | 1,200,833 | | 1,200,833 | | | |

* **This balance expires this year and will not be available next year.**

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 6**

# SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide.*

**Designation under paragraph 111(4)(e) of the *Income Tax Act***

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes [ ] 2 No [X] If **yes**, attach a statement specifying which properties are subject to such a designation.

## Part 1 – Shares

| No. of shares 100 | Name of corporation 105 | Class of shares 106 | Date of acquisition YYYY/MM/DD 110 | Proceeds of disposition 120 | Adjusted cost base 130 | Outlays and expenses (dispositions) 140 | Gain (or loss) (column 120 **minus** cols. 130 and 140) 150 | Foreign source |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| | | | Totals | | | | | |

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . . . . . . . . . . . . . . . . . . . . 160 ______

Actual gain or loss from the disposition of shares (total of line 150 **plus** line 160) . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ A

## Part 2 – Real estate (Do not include losses on depreciable property.)

| Municipal address<br>1 = Address 1<br>2 = Address 2<br>3 = City<br>4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code<br>200 | Date of acquisition YYYY/MM/DD 210 | Proceeds of disposition 220 | Adjusted cost base 230 | Outlays and expenses (dispositions) 240 | Gain (or loss) (column 220 **minus** cols. 230 and 240) 250 | Foreign source |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| Totals | | | | | | B |

## Part 3 – Bonds

| Face value 300 | Maturity date 305 | Name of issuer 307 | Date of acquisition YYYY/MM/DD 310 | Proceeds of disposition 320 | Adjusted cost base 330 | Outlays and expenses (dispositions) 340 | Gain (or loss) (column 320 **minus** cols. 330 and 340) 350 | Foreign source |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| | | | Totals | | | | | C |

## Part 4 – Other properties (Do not include losses on depreciable property.)

| | Description 400 | Date of acquisition YYYY/MM/DD 410 | Proceeds of disposition 420 | Adjusted cost base 430 | Outlays and expenses (dispositions) 440 | Gain (or loss) (column 420 **minus** cols. 430 and 440) 450 | Foreign source |
|---|---|---|---|---|---|---|---|
| 1 | Additional costs on py land disposal | 2011-12-31 | | 3,275 | | -3,275 | |
| | | Totals | | 3,275 | | -3,275 | D |

**Note:**
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

## Part 5 – Personal-use property (Do not include listed personal property.)

| Description 500 | Date of acquisition YYYY/MM/DD 510 | Proceeds of disposition 520 | Adjusted cost base 530 | Outlays and expenses (dispositions) 540 | Gain only (column 520 **minus** cols. 530 and 540) 550 | Foreign source |
|---|---|---|---|---|---|---|
| | | | | | | |
| | **Totals** | | | | | E |

**Note:**
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

## Part 6 – Listed personal property

| Description 600 | Date of acquisition YYYY/MM/DD 610 | Proceeds of disposition 620 | Adjusted cost base 630 | Outlays and expenses (dispositions) 640 | Gain (or loss) (column 620 **minus** cols. 630 and 640) 650 | Foreign source |
|---|---|---|---|---|---|---|
| | | | | | | |
| | **Totals** | | | | | |

**Subtract:** Unapplied listed personal property losses from other years 655

Net gains (or losses) F

**Note:**
Net listed personal property losses can only be applied against listed personal property gains.
The amount on line 655 is from line 530 in Part 5 of Schedule 4, *Corporation Loss Continuity and Application*.

## Part 7 – Determining allowable business investment losses

**Property qualifying for and resulting in an allowable business investment loss**

| Name of small business corporation 900 | Shares, enter 1; debt, enter 2 905 | Date of acquisition YYYY/MM/DD 910 | Proceeds of disposition 920 | Adjusted cost base 930 | Outlays and expenses (dispositions) 940 | Loss only (column 920 **minus** cols. 930 and 940) 950 | Foreign source |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | | **Totals** | | | | | G |

ABILs . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Amount G ________ x 50.0000 % = ________ H
(enter amount H on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*)
**Note:**
Properties listed in Part 7 should not be included in any other parts of Schedule 6.

## Part 8 – Determining capital gains or losses

| | | | |
|---|---|---|---|
| Total of amounts A to F (do not include F if the amount is a loss) | | -3,275 | I |
| **Add:** | | | Foreign source |
| Capital gains dividend received in the year | 875 | | J |
| Capital gains reserve opening balance (from Schedule 13) | 880 | | K |
| Subtotal (**add** amounts I, J, and K) | | -3,275 | L |
| **Deduct:** | | | |
| Capital gains reserve closing balance (from Schedule 13) | 885 | | M |
| Capital gains or losses, excluding ABILs (amount L **minus** amount M) | 890 | -3,275 | |

## Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 above) . . . . . . . . . . -3,275 N

**Deduct** the following gains that are included in amount N:

Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the Act

realized before May 2, 2006 . . . . . . . . . ______ x 50.0000 % = ______ O — Foreign source ☐

realized after May 1, 2006 . . . . . . . . . ______ P — Foreign source ☐

Subtotal (O **plus** P) **895** ______

Gain on donation of ecologically sensitive land

realized before May 2, 2006 . . . . . . . . . ______ x 50.0000 % = ______ Q — Foreign source ☐

realized after May 1, 2006 . . . . . . . . . ______ R — Foreign source ☐

Subtotal (Q **plus** R) **896** ______

**Exempt** portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . . . . . . . ______ R-2 — Foreign source ☐

Total (line 895 **plus** line 896 **plus** line R-2) ______ S

Total capital gains or losses (amount N **minus** amount S) -3,275 T

**Note:**
If amount T is a loss, enter it on line 210 of Schedule 4.

Taxable capital gains: If amount T is a gain, enter it on this line and **multiply** . . . ______ x 50.0000 % = ______ U
(Enter amount U on line 113 of Schedule 1.)

T2 SCH 6 E (10)

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**SCHEDULE 8**

# CAPITAL COST ALLOWANCE (CCA)

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

| | 1 Class number (See Note) 200 | Description | 2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201 | 3 Cost of acquisitions during the year (new property must be available for use)* 203 | 4 Net adjustments** 205 | 5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207 | 6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211 | 7 Reduced undepreciated capital cost | 8 CCA rate % **** 212 | 9 Recapture of capital cost allowance (line 107 of Schedule 1) 213 | 10 Terminal loss (line 404 of Schedule 1) 215 | 11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217 | 12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 1 | | 1,124,339 | | | 0 | | 1,124,339 | 4 | 0 | 0 | 44,974 | 1,079,365 |
| 2. | 8 | | 486,126 | 8,419 | | 0 | 4,210 | 490,335 | 20 | 0 | 0 | 98,067 | 396,478 |
| 3. | 10 | | 692,939 | 309,767 | | 22,300 | 143,734 | 836,672 | 30 | 0 | 0 | 251,002 | 729,404 |
| 4. | 1 | | 32,722,608 | | | 0 | | 32,722,608 | 4 | 0 | 0 | 1,308,904 | 31,413,704 |
| 5. | 47 | | 27,619,786 | 3,335,448 | | 0 | 1,667,724 | 29,287,510 | 8 | 0 | 0 | 2,343,001 | 28,612,233 |
| 6. | 50 | | 24,639 | 173,754 | | 0 | 86,877 | 111,516 | 55 | 0 | 0 | 61,334 | 137,059 |
| 7. | 52 | | | 65,189 | | 0 | | 65,189 | 100 | 0 | 0 | 65,189 | |
| | | **Totals** | 62,670,437 | 3,892,577 | | 22,300 | 1,902,545 | 64,638,169 | | | | 4,172,471 | 62,368,243 |

**Note:** Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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**SCHEDULE 9**

# RELATED AND ASSOCIATED CORPORATIONS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

| | Name 100 | Country of residence (other than Canada) 200 | Business number (see note 1) 300 | Relationship code (see note 2) 400 | Number of common shares you own 500 | % of common shares you own 550 | Number of preferred shares you own 600 | % of preferred shares you own 650 | Book value of capital stock 700 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | BRANTFORD ENERGY CORPORATIC | | 87504 1329 RC0001 | 1 | | | | | |
| 2 | BRANTFORD GENERATION INC. | | 83941 2814 RC0001 | 3 | | | | | |
| 3 | BRANTFORD HYDRO INC. | | 87504 1121 RC0001 | 3 | | | | | |
| 4 | The Corporation of the City of Brant | | 12268 6793 RC0001 | 3 | | | | | |

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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**SCHEDULE 10**

# CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

## Part 1 – Calculation of current year deduction and carry-forward

**Cumulative eligible capital - Balance at the end of the preceding taxation year** (if negative, enter "0") **200** 671,626 A

**Add:** Cost of eligible capital property acquired during the taxation year . . . . . . . . . . **222** ____

Other adjustments . . . . . . . . . . . . . . **226** ____

Subtotal (line 222 plus line 226) ____ x 3 / 4 = ____ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** ____ x 1 / 2 = ____ C

amount B minus amount C (if negative, enter "0") ____ ▶ ____ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . . . . . . . . . . . . . . . . . . . . **224** ____ E

Subtotal (add amounts A, D, and E) **230** 671,626 F

**Deduct:** Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . . . **242** ____ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** ____ H

Other adjustments . . . . . . . . . . . . . . . . . . . . . . . . . . **246** ____ I

(add amounts G,H, and I) ____ x 3 / 4 = **248** ____ J

**Cumulative eligible capital balance** (amount F minus amount J) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 671,626 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 671,626

**less** amount from line 249 ____

**Current year deduction** . . . . . . . . . . . . . . 671,626 x 7.00 % = **250** 47,014 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 47,014 ▶ 47,014 L

**Cumulative eligible capital – Closing balance** (amount K minus amount L) (if negative, enter "0") . . . . . **300** 624,612 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

## Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

| | | | | | |
|---|---|---|---|---|---|
| Amount from line K (show as positive amount) | | | | | N |
| Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 | | 400 | | 1 | |
| Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) | | 401 | | 2 | |
| Total of CEC deductions claimed for taxation years beginning before July 1, 1988 | 402 | 3 | | | |
| Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 | 408 | 4 | | | |
| Line 3 minus line 4 (if negative, enter "0") | | ▶ | | 5 | |
| Total of lines 1, 2 and 5 | | | | 6 | |
| Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 | | 7 | | | |
| Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 | | 8 | | | |
| Subtotal (line 7 plus line 8) | 409 | ▶ | | 9 | |
| Line 6 minus line 9 (if negative, enter "0") | | | | ▶ | O |
| Line N minus line O (if negative, enter "0") | | | | | P |
| Line 5 | | | x 1 / 2 = | | Q |
| Line P minus line Q (if negative, enter "0") | | | | | R |
| Amount R | | | x 2 / 3 = | | S |
| Amount N or amount O, whichever is less | | | | | T |
| **Amount to be included in income** (amount S plus amount T) (enter this amount on line 108 of Schedule 1) | | | | 410 | |

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**SCHEDULE 13**

# CONTINUITY OF RESERVES

| Name of corporation | Business number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

## Part 1 – Capital gains reserves

| | Description of property 001 | Balance at the beginning of the year $ 002 | Transfer on an amalgamation or the wind-up of a subsidiary $ 003 | Add $ | Deduct $ | Balance at the end of the year $ 004 |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| | **Totals** | 008 | 009 | | | 010 |

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

## Part 2 – Other reserves

| Description | | Balance at the beginning of the year $ | Transfer on an amalgamation or the wind-up of a subsidiary $ | Add $ | Deduct $ | Balance at the end of the year $ |
|---|---|---|---|---|---|---|
| Reserve for doubtful debts | | 110 | 115 | | | 120 |
| Reserve for undelivered goods and services not rendered | X | 130 2,508,520 | 135 | 2,073,612 | 2,508,520 | 140 2,073,612 |
| Reserve for prepaid rent | | 150 | 155 | | | 160 |
| Reserve for refundable containers | | 190 | 195 | | | 200 |
| Reserve for unpaid amounts | | 210 | 215 | | | 220 |
| Other tax reserves | | 230 | 235 | | | 240 |
| **Totals** | | 270 2,508,520 | 275 | 2,073,612 | 2,508,520 | 280 2,073,612 |

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

# Continuity of financial statement reserves (not deductible)

## Financial statement reserves (not deductible)

| | Description | Balance at the beginning of the year | Transfer on an amalgamation or the wind-up of a subsidiary | Add | Deduct | Balance at the end of the year |
|---|---|---|---|---|---|---|
| 1 | Employee Future Benefits | 817,515 | | 898,067 | 817,515 | 898,067 |
| 2 | Allowance for Doubtful Account | 608,000 | | 680,000 | 608,000 | 680,000 |
| | Reserves from Part 2 of Schedule 13 | 2,508,520 | | 2,073,612 | 2,508,520 | 2,073,612 |
| | **Totals** | 3,934,035 | | 3,651,679 | 3,934,035 | 3,651,679 |

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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**SCHEDULE 14**

# MISCELLANEOUS PAYMENTS TO RESIDENTS

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

| | Name of recipient 100 | Address of recipient 200 | Royalties 300 | Research and development fees 400 | Management fees 500 | Technical assistance fees 600 | Similar payments 700 |
|---|---|---|---|---|---|---|---|
| 1 | Brantford Energy Corp | 84 Market Square<br>PO Box 308<br>Brantford<br>ON CA<br>N3T 5N8 | | | 151,041 | | |

T2 SCH 14 (99)

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**SCHEDULE 23**

# AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

**Column 1:** Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

**Column 2:** Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

**Column 3:** Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

**Column 4:** Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

**Column 5:** Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

**Column 6:** Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

| Calendar year | Acceptable range |
|---|---|
| 2006 | maximum $300,000 |
| 2007 | $300,001 to $400,000 |

| Calendar year | Acceptable range |
|---|---|
| 2008 | maximum $400,000 |
| 2009 | $400,001 to $500,000 |

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

## Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes [ ] 2 No [X]

| | 1 Names of associated corporations **100** | 2 Business Number of associated corporations **200** | 3 Association code **300** | 4 Business limit for the year (before the allocation) $ | 5 Percentage of the business limit % **350** | 6 Business limit allocated* $ **400** |
|---|---|---|---|---|---|---|
| 1 | BRANTFORD POWER INC. | 86585 8773 RC0001 | 1 | 500,000 | | |
| 2 | BRANTFORD ENERGY CORPORATION | 87504 1329 RC0001 | 1 | 500,000 | | |
| 3 | BRANTFORD GENERATION INC. | 83941 2814 RC0001 | 1 | 500,000 | | |
| 4 | BRANTFORD HYDRO INC. | 87504 1121 RC0001 | 1 | 500,000 | 100.0000 | 500,000 |
| 5 | The Corporation of the City of Brantford | 12268 6793 RC0001 | 4 | | | |
| | | | | **Total** | 100.0000 | 500,000 **A** |

**Business limit reduction under subsection 125(5.1) of the ITA**

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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**SCHEDULE 50**

## SHAREHOLDER INFORMATION

| Name of corporation | Business Number | Tax year end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

| | | Provide only one number per shareholder | | | | |
|---|---|---|---|---|---|---|
| | Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100 | Business Number (If a corporation is not registered, enter "NR") 200 | Social insurance number 300 | Trust number 350 | Percentage common shares 400 | Percentage preferred shares 500 |
| 1 | BRANTFORD ENERGY CORPORATION | 87504 1329 RC0001 | | | 100.000 | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |



Canada

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**SCHEDULE 53**

# GENERAL RATE INCOME POOL (GRIP) CALCULATION

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

## Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

**2006 addition**

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 . . . . . 2006-06-30
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☐ Yes ☐ No
   **If the answer to question 3 is yes, complete Part "GRIP addition for 2006".**

**Change in the type of corporation**

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   **If the answer to question 5 is yes, complete Part 4.**

**Amalgamation (first year of filing after amalgamation)**

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   **If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.**
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   **If the answer to question 7 is yes, complete Part 4.**
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   **If the answer to question 8 is yes, complete Part 3.**

**Winding-up**

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   **If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.**
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 10 is yes, complete Part 4.**
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    **If the answer to question 11 is yes, complete Part 3.**

## Part 1 – Calculation of general rate income pool (GRIP)

| | | | | | |
|---|---|---|---|---|---|
| GRIP at the end of the previous tax year | | | **100** | 23,482,781 | A |
| Taxable income for the year (DICs enter "0") * | **110** | | B | | |
| Income for the credit union deduction * (amount E in Part 3 of Schedule 17) | **120** | | | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * | **130** | | | | |
| For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * | **140** | | | | |
| Subtotal (**add** lines 120, 130, and 140) | | ▶ | C | | |
| Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0") | **150** | | | | |
| After-tax income (line 150 x general rate factor for the tax year ** 0.7 ) | | | **190** | | D |
| Eligible dividends received in the tax year | **200** | | | | |
| Dividends deductible under section 113 received in the tax year | **210** | | | | |
| Subtotal (**add** lines 200 and 210) | | ▶ | | | E |
| GRIP addition: | | | | | |
| Becoming a CCPC (line PP from Part 4) | **220** | | | | |
| Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4) | **230** | | | | |
| Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4) | **240** | | | | |
| Subtotal (**add** lines 220, 230, and 240) | | ▶ | **290** | | F |
| Subtotal (**add** lines A, D, E, and F) | | | | 23,482,781 | G |
| Eligible dividends paid in the previous tax year | **300** | | | | |
| Excessive eligible dividend designations made in the previous tax year | **310** | | | | |
| **Note:** If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. | | | | | |
| Subtotal (line 300 **minus** line 310) | | ▶ | | | H |
| GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative) | | | **490** | 23,482,781 | |
| Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) | | | **560** | 843,444 | |
| **GRIP at the end of the tax year** (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55. | | | **590** | 22,639,337 | |

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

**First previous tax year** 2010-12-31

| | | | | |
|---|---|---|---|---|
| Taxable income before specified future tax consequences from the current tax year | | 3,155,608 J1 | | |
| Enter the following amounts before specified future tax consequences from the current tax year: | | | | |
| Income for the credit union deduction (amount E in Part 3 of Schedule 17) | K1 | | | |
| Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less | L1 | | | |
| Aggregate investment income (line 440 of the T2 return) | 3,694 M1 | | | |
| Subtotal (**add** lines K1, L1, and M1) | 3,694 ▶ | 3,694 N1 | | |
| Subtotal (line J1 **minus** line N1) (if negative, enter "0") | | 3,151,914 | ▶ | 3,151,914 O1 |

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | 1,638 | | | | 1,638 |

Taxable income after specified future tax consequences . . . . . . . . 3,153,970 P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R1

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ____ S1

Subtotal (**add** lines Q1, R1, and S1) ____ ► ____ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") 3,153,970 ► 3,153,970 U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ____ V1

**GRIP adjustment for specified future tax consequences to the first previous tax year**

(line V1 **multiplied by** the general rate factor for the tax year 0.7 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **500** ____

**Second previous tax year** 2009-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 4,562,815 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ L2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . 2,463 M2

Subtotal (**add** lines K2, L2, and M2) 2,463 ► 2,463 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 4,560,352 ► 4,560,352 O2

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| | | | | | |

Taxable income after specified future tax consequences . . . . . . . . ____ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R2

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ____ S2

Subtotal (**add** lines Q2, R2, and S2) ____ ► ____ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ____ ► ____ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ____ V2

**GRIP adjustment for specified future tax consequences to the second previous tax year**

(line V2 **multiplied by** the general rate factor for the tax year 0.7 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **520** ____

## Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

**Third previous tax year** 2008-12-31

Taxable income before specified future tax consequences from the current tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . 8,140,016 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . 2,463 M3

Subtotal (**add** lines K3, L3, and M3) 2,463 ▶ 2,463 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 8,137,553 ▶ 8,137,553 O3

| Future tax consequences that occur for the current year<br>Amount carried back from the current year to a prior year | | | | | |
|---|---|---|---|---|---|
| **Non-capital loss carry-back (paragraph 111 (1)(a) ITA)** | **Capital loss carry-back** | **Restricted farm loss carry-back** | **Farm loss carry-back** | **Other** | **Total carrybacks** |
| 1,207,383 | | | | | 1,207,383 |

Taxable income after specified future tax consequences . . . . . . . . 6,932,633 P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . . . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") 6,932,633 ▶ 6,932,633 U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") 1,204,920 V3

**GRIP adjustment for specified future tax consequences to the third previous tax year**
(line V3 **multiplied by** the general rate factor for the tax year 0.7 ) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **540** 843,444

**Total GRIP adjustment for specified future tax consequences to previous tax years:**
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 843,444 W

Enter amount W on line 560.

## Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

**nb. 1** Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . . . . . . . . . . . . . . . . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)**
(line AA **minus** line DD) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

**nb. 1** Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . . . . . . . ☐ Post wind-up . . . . . . . . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . ________ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . ________ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________
Net capital losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________
Farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________
Restricted farm losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________
Limited partnership losses . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________

Subtotal ________ ► ________ HH

Subtotal (**add** lines FF, GG, and HH) ________ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . ________ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . ________ KK

All the corporation's reserves deducted in its previous/last tax year . . . . . . . . . . . . . . . . . . . ________ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . ________ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ________ ► ________ OO

**GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC** (line II **minus** line OO) (if negative, enter "0") . . . . . . . . . . . . . . . . . . . . . ________ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

## Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

| | | | | |
|---|---|---|---|---|
| 0.68 | x | number of days in the tax year before January 1, 2010 / number of days in the tax year 365 | = | QQ |
| 0.69 | x | number of days in the tax year in 2010 / number of days in the tax year 365 | = | RR |
| 0.7 | x | number of days in the tax year in 2011 365 / number of days in the tax year 365 | = 0.70000 | SS |
| 0.72 | x | number of days in the tax year after December 31, 2011 / number of days in the tax year 365 | = | TT |

**General rate factor for the tax year** (total of lines QQ to TT) . . . . . . . . . . . . . . . . . . . . 0.70000 UU

Canada Revenue Agency / Agence du revenu du Canada

**SCHEDULE 55**

# PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

| Name of corporation | Business Number | Tax year-end Year Month Day |
|---|---|---|
| BRANTFORD POWER INC. | 86585 8773 RC0001 | 2011-12-31 |

**Do not use this area**

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

## Part 1 – Canadian-controlled private corporations and deposit insurance corporations

| | Line | Amount | Line | Amount | |
|---|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | 1,450,000 | | | |
| Total taxable dividends paid in the tax year | 100 | 1,450,000 | | | |
| Total eligible dividends paid in the tax year | | | 150 | | A |
| GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0") | | | 160 | 22,639,337 | B |
| Excessive eligible dividend designation (line 150 **minus** line 160) | | | | | C |
| **Deduct**: | | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends* | | | 180 | | D |
| Subtotal (amount C **minus** amount D) | | | | | E |
| **Part III.1 tax on excessive eligible dividend designations – CCPC or DIC** (amount E **multiplied** by 20 %) | | | 190 | | F |

Enter the amount from line 190 on line 710 of the T2 return.

## Part 2 – Other corporations

| | Line | Amount | Line | Amount | |
|---|---|---|---|---|---|
| Taxable dividends paid in the tax year **not included** in Schedule 3 | | | | | |
| Taxable dividends paid in the tax year **included** in Schedule 3 | | | | | |
| Total taxable dividends paid in the tax year | 200 | | | | |
| Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54) | | | | | G |
| **Deduct**: | | | | | |
| Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends* | | | 280 | | H |
| Subtotal (amount G **minus** amount H) | | | | | I |
| **Part III.1 tax on excessive eligible dividend designations – Other corporations** (amount I **multiplied** by 20 %) | | | 290 | | J |

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

# Corporate Taxpayer Summary

## Corporate information

Corporation's name . . . . . . . . . . . . BRANTFORD POWER INC.

Taxation Year . . . . . . . . . . . . . . . 2011-01-01 to 2011-12-31

Jurisdiction . . . . . . . . . . . . . . . . Ontario

| BC | AB | SK | MB | ON | QC | NB | NS | NO | PE | NL | XO | YT | NT | NU | OC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ☐ | ☐ | ☐ | ☐ | X | ☐ | ☐ | ☐ | ☐ | ☐ | ☐ | ☐ | ☐ | ☐ | ☐ | ☐ |

Corporation is associated . . . . . . . . Y

Corporation is related . . . . . . . . . . . Y

Number of associated corporations . . . 4

Type of corporation . . . . . . . . . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . . . . . . . . . . . .

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

## Summary of federal information

| | | |
|---|---|---|
| Net income | | -1,200,833 |
| Taxable income | | |
| Donations | | 1,450 |
| Calculation of income from an active business carried on in Canada | | |
| Dividends paid | | 1,450,000 |
| Dividends paid – Regular | 1,450,000 | |
| Dividends paid – Eligible | | |
| Balance of the low rate income pool at the end of the previous year | | |
| Balance of the low rate income pool at the end of the year | | |
| Balance of the general rate income pool at the end of the previous year | | 23,482,781 |
| Balance of the general rate income pool at the end of the year | | 22,639,337 |
| Part I tax (base amount) | | |

## Summary of federal carryforward/carryback information

**Carryback amounts**

| | |
|---|---|
| Non-capital losses | 1,200,833 |
| Capital losses | 3,275 |

**Carryforward balances**

| | |
|---|---|
| Charitable donations | 1,450 |
| Unused surtax credit (Schedule 37) | 60,412 |
| Capital dividend amount | 10,676 |
| Cumulative eligible capital | 624,612 |
| Financial statement reserve | 3,651,679 |
| Other reserves | 2,073,612 |

## Summary of provincial information – provincial income tax payable

| | Ontario | Québec (CO-17) | Alberta (AT1) |
|---|---|---|---|
| Net income | -1,200,833 | | |
| Taxable income | | | |
| % Allocation | 100.00 | | |
| Attributed taxable income | | | |
| Surtax | | N/A | N/A |
| Tax payable before deduction* | | | |
| Deductions and credits | | | |
| Net tax payable | | | |
| Attributed taxable capital | | | N/A |
| Capital tax payable** | | | N/A |
| Total tax payable*** | | | |
| Instalments and refundable credits | | | |
| Balance due/Refund (-) | | | |
| **Logging tax payable** | | | |
| Tax payable | N/A | | N/A |

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

## Summary – taxable capital

**Federal**

| Corporate name | Taxable capital used to calculate the business limit reduction (T2, line 415) | Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49) | Taxable capital used to calculate line 233 of the T2 return | Taxable capital used to calculate line 234 of the T2 return |
|---|---|---|---|---|
| BRANTFORD POWER INC. | 76,405,140 | 76,405,140 | 78,145,607 | 78,145,607 |
| BRANTFORD ENERGY CORPORATION | 70,001 | 70,001 | | |
| BRANTFORD GENERATION INC. | 11,818,769 | 11,818,769 | | |
| BRANTFORD HYDRO INC. | 3,572,671 | 3,572,671 | | |
| The Corporation of the City of Brantford | | | | |
| Total | 91,866,581 | 91,866,581 | 78,145,607 | 78,145,607 |

**Québec**

| Corporate name | Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30) | Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18) | Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3) | Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN) | Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E) |
|---|---|---|---|---|---|
| | | | | | |
| Total | | | | | |

**Ontario**

| Corporate name | Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514) | Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515) | Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566) |
|---|---|---|---|
| | | | |
| Total | | | |

**Other provinces**

| Corporate name | Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306) | Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343) | Net paid up capital – BC capital tax on financial institutions (FIN 689) | BC paid up capital – BC capital tax on financial institutions (FIN 689) |
|---|---|---|---|---|
| | | | | |
| Total | | | | |

# Five-Year Comparative Summary

### Federal information (T2)

| | Current year | 1st prior year | 2nd prior year | 3rd prior year | 4th prior year |
|---|---|---|---|---|---|
| Taxation year end | **2011-12-31** | **2010-12-31** | **2009-12-31** | **2008-12-31** | **2007-12-31** |
| Net income | -1,200,833 | 3,162,683 | 4,562,815 | 8,140,016 | 9,503,457 |
| Taxable income | | 3,155,608 | 4,562,815 | 8,140,016 | 9,503,457 |
| Active business income | | 3,158,989 | 4,560,352 | 8,137,553 | 9,499,763 |
| Dividends paid | 1,450,000 | 750,000 | 750,000 | 500,000 | 500,000 |
| Dividends paid – Regular | 1,450,000 | 750,000 | | | |
| Dividends paid – Eligible | | | | | |
| LRIP – end of the previous year | | | | | |
| LRIP – end of the year | | | | | |
| GRIP – end of the previous year | 23,482,781 | 21,307,960 | 18,206,921 | 12,673,385 | 6,213,546 |
| GRIP – end of the year | 22,639,337 | 23,482,781 | 21,307,960 | 18,206,921 | 12,673,385 |
| Donations | 1,450 | 7,075 | | | |
| Balance due/refund (-) | | -608,058 | -1,228,548 | | |

### Federal taxes

| | Current year | 1st prior year | 2nd prior year | 3rd prior year | 4th prior year |
|---|---|---|---|---|---|
| Part I before surtax | | 568,625 | 867,320 | 1,587,676 | 1,996,231 |
| Surtax | | | | | 106,439 |
| Part I.3 | | | | | |
| Part IV | | | | | |
| Part I & Surtax | | 568,625 | 867,320 | 1,587,676 | 2,102,670 |
| Part III.1 | | | | | |
| Other* | | | | | |

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

### Credits against part I tax

| | Current year | 1st prior year | 2nd prior year | 3rd prior year | 4th prior year |
|---|---|---|---|---|---|
| Small business deduction | | | | | |
| M&P deduction | | | | | |
| Foreign tax credit | | | | | |
| Political contribution | | | | | |
| Investment tax credit | | | | | |
| Abatement/other* | | 630,752 | 866,714 | 1,505,694 | 1,615,329 |

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

### Refunds/credits

| | Current year | 1st prior year | 2nd prior year | 3rd prior year | 4th prior year |
|---|---|---|---|---|---|
| ITC refund | | | | | |
| Dividend refund | | 985 | 657 | 657 | 985 |
| Instalments | | 1,632,950 | 2,860,841 | 1,587,019 | 2,101,685 |
| Surtax credit | | | | | |
| Other* | | | | | |

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

## Ontario

| Taxation year end | 2011-12-31 | 2010-12-31 | 2009-12-31 | 2008-12-31 | 2007-12-31 |
|---|---|---|---|---|---|
| Net income | -1,200,833 | 3,162,683 | | 8,140,016 | 9,503,457 |
| Taxable income | | 3,155,608 | | 8,140,016 | 9,503,457 |
| % Allocation | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 |
| Attributed taxable income | | 3,155,608 | | 8,140,016 | 9,503,457 |
| Surtax | | 39,979 | 42,500 | 42,500 | 34,000 |
| Income tax payable before deduction | | 409,970 | 638,794 | 1,139,602 | 1,330,484 |
| Income tax deductions /credits | | 39,979 | 42,500 | 42,500 | 34,000 |
| Net income tax payable | | 409,970 | 638,794 | 1,139,602 | 1,330,484 |
| Taxable capital | | 76,030,482 | 69,056,614 | 73,107,253 | 73,526,197 |
| Capital tax payable | | 47,282 | 126,836 | 133,563 | 174,947 |
| Total tax payable* | | 457,252 | 765,630 | 1,273,165 | 1,505,431 |
| Instalments and refundable credits | | | | 2,059,472 | 994,779 |
| Balance due/refund** | | 457,252 | 765,630 | -786,307 | 510,652 |

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

## CAPITAL COST ALLOWANCE

BPI is providing Capital Cost Allowance continuity schedules for the 2012 Bridge Year (Table 4.48 and 4.49) and the 2013 Test Year (Table 4.50 and 4.51) as follows:

### Table 4.48 – 2012 CCA / UCC Continuity Schedule

| Class | Class Description | UCC Prior Year Ending Balance | Less: Non-Distribution Portion | Less: Disallowed FMV Increment | UCC Bridge Year Opening Balance | Additions | Dispositions | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | CCA | UCC Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - 1988 to 22-Feb-2005 | 32,493,069 | 0 | 0 | 32,493,069 | 0 | 0 | 32,493,069 | 0 | 32,493,069 | 4% | 1,299,723 | 31,193,346 |
| 2 | Distribution System - pre 1988 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6% | 0 | 0 |
| 6 | Buildings - after 1990 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10% | 0 | 0 |
| 8 | General Office/Stores Equip | 396,478 | 0 | 0 | 396,478 | 30,000 | 0 | 426,478 | 15,000 | 411,478 | 20% | 82,296 | 344,182 |
| 10 | Computer Hardware/ Vehicles | 729,404 | 0 | 0 | 729,404 | 326,000 | 0 | 1,055,404 | 163,000 | 892,404 | 30% | 267,721 | 787,683 |
| 10.1 | Certain Automobiles | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30% | 0 | 0 |
| 12 | Computer Software | | 0 | 0 | 0 | 180,900 | 0 | 180,900 | 90,450 | 90,450 | 100% | 90,450 | 90,450 |
| 3 | Buildings - pre 1990 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5% | 0 | 0 |
| | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| 13 3 | Lease # 3 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| 13 4 | Lease # 4 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| 14 | Franchise | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 8% | 0 | 0 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30% | 0 | 0 |
| 45 | Computers & Systems Hardware acq'd post Mar 22/04 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45% | 0 | 0 |
| 50 | Computers & Systems Hardware acq'd post Mar 19/07 | 137,059 | 0 | 0 | 137,059 | 0 | 0 | 137,059 | 0 | 137,059 | 55% | 75,382 | 61,677 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30% | 0 | 0 |
| 47 | Distribution System - post 22-Feb-2005 | 28,612,233 | | | 28,612,233 | 3,658,399 | 0 | 32,270,632 | 1,829,200 | 30,441,433 | 8% | 2,435,315 | 29,835,317 |
| | **SUB-TOTAL - UCC** | **62,368,243** | **0** | **0** | **62,368,243** | **4,195,299** | **0** | **66,563,542** | **2,097,650** | **64,465,893** | | **4,250,887** | **62,312,655** |
| | | | | | | | | | | | | | |
| CEC | Goodwill | | 0 | 0 | 0 | | | | | | | | |
| CEC | Land Rights | | 0 | 0 | 0 | | | | | | | | |
| CEC | FMV Bump-up | | 0 | 0 | 0 | | | | | | | | |
| | **SUB-TOTAL - CEC** | **0** | **0** | **0** | **0** | | | | | | | | |

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

## 1 Table 4.49 – 2012 CEC Continuity Schedule

**Cumulative Eligible Capital Calculation**

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | 624,612 |
| **Additions:** | | | | |
| **Cost of Eligible Capital Property Acquired during the year** | 64700 | | | |
| **Other Adjustments** | 0 | | | |
| **Subtotal** | 64700 | x 3/4 = | 48525 | |
| **Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002** | 0 | x 1/2 = | 0 | |
| | | | 48525 | 673,137 |
| **Amount transferred on amalgamation or wind-up of subsidiary** | 0 | | | 0 |
| **Subtotal** | | | | 673,137 |
| **Deductions:** | | | | |
| **Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year** | | | | |
| **Other Adjustments** | 0 | | | |
| **Subtotal** | 0 | x 3/4 = | 0 | 673,137 |
| **Cumulative Eligible Capital Balance** | | | | 673,137 |
| **CEC Deduction** | 7% | | | 47,120 |
| **Cumulative Eligible Capital - Closing Balance** | | | | 626,017 |

## 2 Table 4.50 – 2013 CCA / UCC Continuity Schedule

| Class | Class Description | UCC Prior Year Ending Balance | Less: Non-Distribution Portion | Less: Disallowed FMV Increment | UCC Bridge Year Opening Balance | Additions | Dispositions | UCC Before 1/2 Yr Adjustment | 1/2 Year Rule {1/2 Additions Less Disposals} | Reduced UCC | Rate % | CCA | UCC Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Distribution System - 1988 to 22-Feb-2005 | 31,193,346 | 0 | 0 | 31,193,346 | 0 | 0 | 31,193,346 | 0 | 31,193,346 | 4% | 1,247,734 | 29,945,612 |
| 2 | Distribution System - pre 1988 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6% | 0 | 0 |
| 6 | Buildings - after 1990 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10% | 0 | 0 |
| 8 | General Office/Stores Equip | 344,182 | 0 | 0 | 344,182 | 25,000 | 0 | 369,182 | 12,500 | 356,682 | 20% | 71,336 | 297,846 |
| 10 | Computer Hardware/ Vehicles | 787,683 | 0 | 0 | 787,683 | 277,500 | 0 | 1,065,183 | 138,750 | 926,433 | 30% | 277,930 | 787,253 |
| 10.1 | Certain Automobiles | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30% | 0 | 0 |
| 12 | Computer Software | 90,450 | 0 | 0 | 90,450 | 310,000 | 0 | 400,450 | 155,000 | 245,450 | 100% | 245,450 | 155,000 |
| 3 | Buildings - pre 1990 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5% | 0 | 0 |
| | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0% | 0 | 0 |
| 13 3 | Lease # 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| 13 4 | Lease # 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| 14 | Franchise | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 | 0 |
| 17 | New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 8% | 0 | 0 |
| 43.1 | Certain Energy-Efficient Electrical Generating Equipment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30% | 0 | 0 |
| 45 | Computers & Systems Hardware acq'd post Mar 22/04 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45% | 0 | 0 |
| 50 | Computers & Systems Hardware acq'd post Mar 19/07 | 61,677 | 0 | 0 | 61,677 | 0 | 0 | 61,677 | 0 | 61,677 | 55% | 33,922 | 27,754 |
| 46 | Data Network Infrastructure Equipment (acq'd post Mar 22/04) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30% | 0 | 0 |
| 47 | Distribution System - post 22-Feb-2005 | 29,835,317 | | | 29,835,317 | 2,827,661 | 0 | 32,662,978 | 1,413,831 | 31,249,148 | 8% | 2,499,932 | 30,163,047 |
| | **SUB-TOTAL - UCC** | **62,312,655** | **0** | **0** | **62,312,655** | **3,440,161** | **0** | **65,752,816** | **1,720,081** | **64,032,736** | | **4,376,304** | **61,376,512** |
| | | | | | | 1,766,310 | 0 | | | | | | |
| CEC | Goodwill | 0 | 0 | 0 | 0 | | | | | | | | |
| CEC | Land Rights | 0 | 0 | 0 | 0 | | | | | | | | |
| CEC | FMV Bump-up | 0 | 0 | 0 | 0 | | | | | | | | |
| | **SUB-TOTAL - CEC** | **0** | **0** | **0** | **0** | | | | | | | | |

1 **Table 4.51 - 2013 CEC Continuity Schedule**

**Cumulative Eligible Capital Calculation**

| | | | | |
|---|---|---|---|---|
| **Cumulative Eligible Capital** | | | | 626,017 |
| **Additions:** | | | | |
| **Cost of Eligible Capital Property Acquired during the year** | 0 | | | |
| **Other Adjustments** | 0 | | | |
| **Subtotal** | 0 | x 3/4 = | 0 | |
| **Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002** | 0 | x 1/2 = | 0 | |
| | | | 0 | 626,017 |
| **Amount transferred on amalgamation or wind-up of subsidiary** | 0 | | | 0 |
| **Subtotal** | | | | 626,017 |
| **Deductions:** | | | | |
| **Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year** | | | | |
| **Other Adjustments** | 0 | | | |
| **Subtotal** | 0 | x 3/4 = | 0 | 626,017 |
| **Cumulative Eligible Capital Balance** | | | | 626,017 |
| **CEC Deduction** | 7% | | | 43,821 |
| **Cumulative Eligible Capital - Closing Balance** | | | | 582,196 |

## CONSERVATION AND DEMAND MANAGEMENT ("CDM") COSTS

In BPI's 2012 IRM Application (EB-2011-0147), the Board Approved BPI's LRAM claim as a result of persistence from 2006 to 2010 from programs that were in effect from 2005 to 2010, stating:

> *The Board will approve an LRAM claim of $515,439.19, comprised of the effect of programs launched in 2005 to 2010 and persistence thereof in 2006 to 2010. Although the CDM Guideline states that lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time, the Board has acknowledged (PowerStream decision EB-2011-0005 and PUC decision EB-2011-0101) that the 2004 NAC based load forecast underpinning Brantford's cost of service rates does not include the impact of Brantford's CDM programs. The Board also notes that with the exception of 2008, Brantford was under IRM during the subject time period and did not otherwise receive compensation for lost revenues from these programs. The Board will not approve lost revenues arising from these programs in 2011, as it is premature to do so and inconsistent with the CDM Guidelines. (Page 16)*

BPI is requesting approval and recovery of historical Lost Revenue Adjustment Mechanism ("LRAM") amounts related to persistence of 2005-2010 Conservation and Demand Management (CDM) activities in 2011, which was not approved in BPI's 2012 IRM application as stated above in the Board's Decision. The total amount for recovery is a balance of $118,455.70. BPI has used the most recent input assumptions in calculating the LRAM persistence amount, as supported by the 2011 OPA Final Evaluation Report. A copy of the OPA Report has also been submitted in Excel format as part of this Cost-of-Service Rate Application in Appendix F. Also, as discussed in the Board decision above, the load forecast submitted as part of BPI's 2008 Cost-of-Service Rate Application did not include any impacts as a result of CDM activities.

Furthermore, a third party report completed by Burman Energy, providing review and verification of the LRAM persistence calculations, can be found in Appendix G.

### Recovery

BPI requests recovery of the LRAM persistence amounts by way of volumetric rate rider over a one-year period. No carrying charges are being requested.

Table 4.52 sets the rate rider for recovery of the LRAM amount by the respective rate class. The LRAM dollar amount by rate class is a calculation that was performed by Burman Energy and can be found in the Burman Energy LRAM report attached in Appendix G. In order to determine the actual rate riders, the LRAM amount was divided by the 2013 billing determinants from the load forecast.

**Table 4.52 - LRAM Amounts and Rate Riders by Class**

| Rate Class | LRAM | 2013 Forecasted | Metrics | Rate Rider |
|---|---|---|---|---|
| | $ | Billed kWh/kW | | $/unit (kWh or kW) |
| **Residential** | 75,201.69 | 280,913,502 | kWh | 0.0003 |
| **GS < 50 kW** | 22,044.37 | 97,535,297 | kWh | 0.0002 |
| **GS 50 to 4999** | 21,209.63 | 1,354,270 | kW | 0.0157 |
| **Total** | 118,455.69 | 379,803,068 | | |

## LRAM Variance Account

### 1568 LRAM Variance Account

This account includes the LRAM variances in relation to the CDM programs or activities undertaken by a distributor in accordance with Board prescribed requirements (e.g. license, codes and guidelines). Since 2011, BPI has delivered a full slate of CDM programs offered by the Ontario Power Authority (“OPA”).

BPI has booked the following estimated lost revenue amounts as a result of those CDM programs to this account:

| | |
|---|---|
| 2011 Estimated Lost Revenue | $33,041.49 |
| 2011 Estimated Persistence into 2012 | $33,041.49 |
| 2012 Estimated Lost Revenue | $29,446.47 |
| **Total** | **$95,502.75** |

BPI notes that for 2012 programs in particular, the amounts recorded in the LRAM variance account are based on estimates as the final program results from the OPA have not yet been released. Because the amounts in this account are estimates, BPI advises that it is not seeking disposition on the amounts in this account at this time.

# APPENDIX F

# 2011 OPA FINAL EVALUATION REPORT

**Message from the Vice President:**

The OPA is pleased to provide you with the enclosed Final 2011 Results Report.

Despite some of the inertial challenges in 2011 with program start up, on average, year one province-wide forecasts were met and the year finished out with strong momentum which continues to build 2012. There are still challenges for LDCs of all sizes and we are committed to ensuring LDCs are successful in meeting their objectives. We look forward to further dialogue to discover opportunities to improve the current program suite with local program opportunities, best practices and successes to better reach our customers in the years to come.

This report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. Between the draft and final reports several improvements were made to improve clarity and transparency based on feedback provided by LDCs, such as: the addition of a glossary tab, total adjustments to savings are now broken out into both the realization rate and net-to-gross ratio for both peak demand and energy savings and modifications were made to the methodology tab. We invite you to continue to provide your feedback.

All results are now considered final for 2011. Any additional 2011 program activity not captured will be reported in the Final 2012 Results Report. Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2012.

Sincerely,
Andrew Pride

## Table of Contents

## OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

**LDC:** Brantford Power Inc.

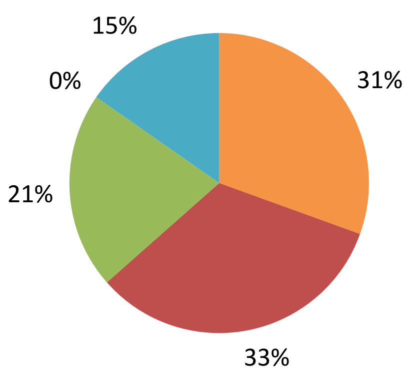
| FINAL 2011 Progress to Targets | Incremental 2011 | Scenario 1: % of Target Achieved | Scenario 2: % of Target Achieved |
|---|---|---|---|
| **Net Annual Peak Demand Savings (MW)** | 1.2 | **8.4%** | **10.8%** |
| **Net Cumulative Energy Savings (GWh)** | 4.5 | **36.6%** | **36.7%** |

**Scenario 1** = Assumes that demand resource resources have a persistence of 1 year

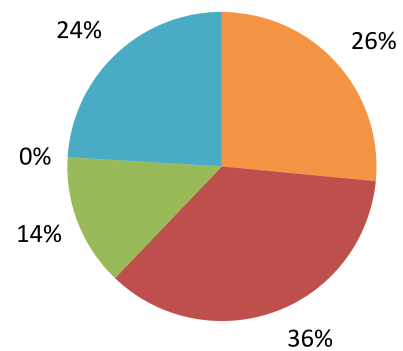
**Scenario 2** = Assumes that demand response resources remain in your territory until 2014

## Achievement by Sector

### 2011 Incremental Peak Demand Savings (MW)




### 2011 Incremental Energy Savings (GWh)

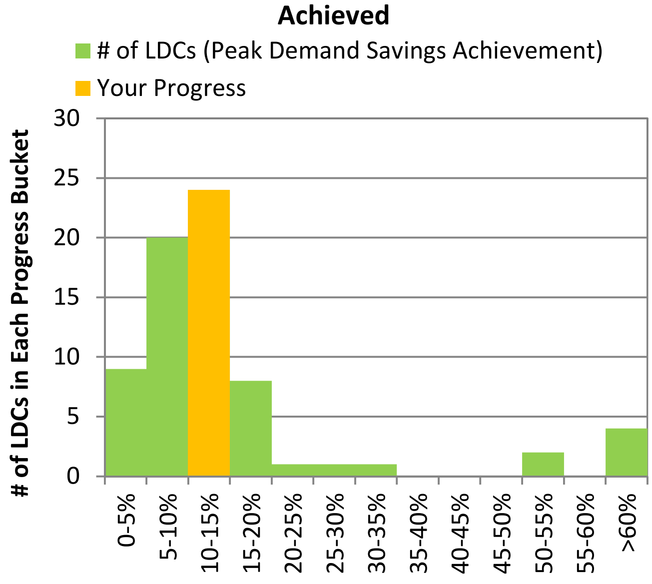



Consumer Program Total
Business Program Total
Industrial Program Total
Home Assistance Program Total
Pre-2011 Programs completed in 2011 Total

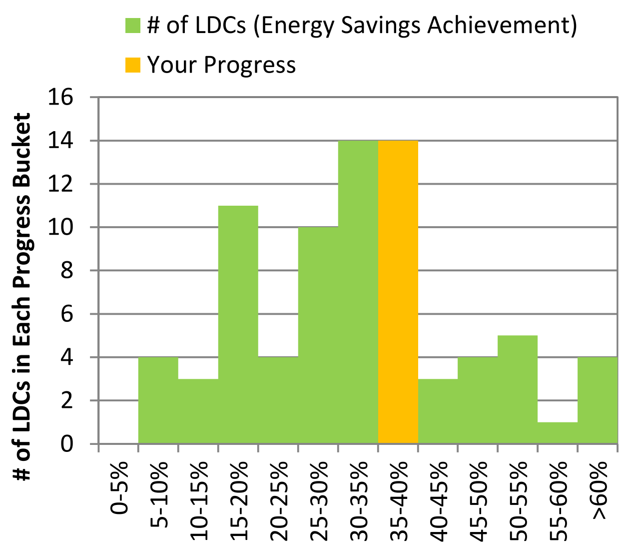
## Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

### % of OEB Peak Demand Savings Target Achieved




### % of OEB Energy Savings Target Achieved



% of OEB Target Achieved

% of OEB Target Achieved

## Table 1: Participation[1]

| # | Initiative | Unit | Uptake/ Participation Units |
|---|---|---|---|
| **Consumer Program** | | | |
| 1 | Appliance Retirement | Appliances | 607 |
| 2 | Appliance Exchange | Appliances | 81 |
| 3 | HVAC Incentives | Equipment | 1,092 |
| 4 | Conservation Instant Coupon Booklet | Products | 3,702 |
| 5 | Bi-Annual Retailer Event | Products | 6,314 |
| 6 | Retailer Co-op | Products | 0 |
| 7 | Residential Demand Response | Devices | 0 |
| 8 | Residential New Construction | Houses | 0 |
| **Business Program** | | | |
| 9 | Efficiency: Equipment Replacement | Projects | 20 |
| 10 | Direct Install Lighting | Projects | 102 |
| 11 | Existing Building Commissioning Incentive | Buildings | 0 |
| 12 | New Construction and Major Renovation Incentive | Buildings | 0 |
| 13 | Energy Audit | Audits | 0 |
| 14 | Commercial Demand Response (part of the Residential program schedule) | Devices | 0 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | Facilities | 2 |
| **Industrial Program** | | | |
| 16 | Process & System Upgrades | Projects[2] | 0 |
| 17 | Monitoring & Targeting | Projects[3] | 0 |
| 18 | Energy Manager | Managers[2 3] | 0 |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | Projects | 12 |
| 20 | Demand Response 3 | Facilities | 2 |
| **Home Assistance Program** | | | |
| 21 | Home Assistance Program | Homes | 0 |
| **Pre 2011 Programs Completed in 2011** | | | |
| 22 | Electricity Retrofit Incentive Program | Projects | 29 |
| 23 | High Performance New Construction | Projects | 1 |
| 24 | Toronto Comprehensive | Projects | 0 |
| 25 | Multifamily Energy Efficiency Rebates | Projects | 0 |
| 26 | Data Centre Incentive Program | Projects | 0 |
| 27 | EnWin Green Suites | Projects | 0 |

[1] *Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

**Table 3: OPA Province-Wide Evaluation Findings**

| # | Initiative | OPA Province-Wide Key Evaluation Findings |
|---|---|---|
| **Consumer Program** | | |
| 1 | Appliance Retirement | * Overall participation continues to decline year over year<br>    * Participation declined 17% from 2010 (from over 67,000 units in 2010 to over 56,000 units in 2011)<br>* 97% of net resource savings achieved through the home pick-up stream<br>    * Measure Breakdown: 66% refrigerators, 30% freezers, 4% Dehumidifiers and window air conditioners<br>* 3% of net resource savings achieved through the Retailer pick-up stream<br>    * Measure Breakdown: 90% refrigerators, 10% freezers<br>* Net-to-Gross ratio for the initiative was 50%<br>    * Measure-level free ridership ranges from 82% for the retailer pick-up stream to 49% for the home pick-up stream<br>    * Measure-level spillover ranges from 3.7% for the retailer pick-up stream to 1.7% for the home pick-up stream |
| 2 | Appliance Exchange | * Overall eligible units exchanged declined by 36% from 2010 (from over 5,700 units in 2010 to<br>    * Measure Breakdown: 75% window air conditioners, 25% dehumidifiers<br>* Dehumidifiers and window air conditioners contributed almost equally to the net energy<br>    * Dehumidifiers provide more than three times the energy savings per unit than window air conditioners<br>* Window air conditioners contributed to 64% of the net peak demand savings achieved<br>* Approximately 96% of consumers reported having replaced their exchanged units (as opposed to retiring the unit)<br>* Net-to-Gross ratio for the initiative is consistent with previous evaluations (51.5%) |
| 3 | HVAC Incentives | * Total air conditioner and furnace installations increased by 14% (from over 95,800 units in 2010 to over 111,500 units in 2011)<br>    * Measure Breakdown: 64% furnaces, 10% tier 1 air conditioners (SEER 14.5) and 26% tier 2 air conditioners (SEER 15)<br>    * Measure breakdown did not change from 2010 to 2011<br>* The HVAC Incentives initiative continues to deliver the majority of both the energy (45%) and demand (83%) savings in the consumer program<br>    * Furnaces accounted for over 91% of energy savings achieved for this initiative<br>* Net-to-Gross ratio for the initiative was 17% higher than 2010 (from 43% in 2010 to 60% in<br>    * Increase due in part to the removal of programmable thermostats from the program, and an increase in the net-to-gross ratio for both Furnaces and Tier 2 air conditioners (SEER 15) |
| 4 | Conservation Instant Coupon Booklet | * Customers redeemed nearly 210,000 coupons, translating to nearly 560,000 products<br>    * Majority of coupons redeemed were downloadable (~40%) or LDC-branded (~35%)<br>    * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (37%), followed by multi-packs of specialty CFLs (17%)<br>* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings<br>* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed |

| # | Initiative | OPA Province-Wide Key Evaluation Findings |
|---|---|---|
| 5 | Bi-Annual Retailer Event | * Customers redeemed nearly 370,000 coupons, translating to over 870,000 products<br>* Majority of coupons redeemed were for multi-packs of standard spiral CFLs (49%), followed by multi-packs of specialty CFLs (16%)<br>* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings<br>* Standard CFLs and heavy duty outdoor timers were reintroduced to the initiative in 2011 and contributed more than 64% of the initiative's 2011 net annual energy savings<br>* While the volume of coupons redeemed for heavy duty outdoor timers was relatively small (less than 1%), the measure accounted for 10% of net annual savings due to high per unit savings<br>* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed. |
| 6 | Retailer Co-op | * Initiative was not evaluated in 2011 due to low uptake. Verified Bi-Annual Retailer Event per unit assumptions and free-ridership rates were used to calculate net resource savings |
| 7 | Residential Demand Response | * Approximately 20,000 new devices were installed in 2011<br>* 99% of the new devices enrolled controlled residential central AC (CAC)<br>* 2011 only saw 1 atypical event (in both weather and timing) that had limited participation<br>* The ex ante impact developed through the 2009/2010 evaluations was maintained for 2011; residential CAC: 0.56 kW/device, commercial CAC: 0.64 kW/device, and Electric Water Heaters: 0.30 kW/device |
| 8 | Residential New Construction | * Initiative was not evaluated in 2011 due to limited uptake<br>* Business case assumptions were used to calculate savings |
| **Business Program** | | |
| 9 | Efficiency: Equipment Replacement | * Gross verified energy savings were boosted by lighting projects in the prescriptive and<br>* Lighting projects overall were determined to have a realization rate of 112%; 116% when including interactive energy changes<br>* On average, the evaluation found high realization rates as a result of both longer operating hours and larger wattage reductions than initial assumptions<br>* Low realization rates for engineered lighting projects due to overstated operating hour assumptions<br>* Custom non-lighting projects suffered from process issues such as: the absence of required M&V plans, the use of inappropriate assumptions , and the lack of adherence to the M&V plan<br>* The final realization rate for summer peak demand was 94%<br>* 84% was a result of different methodologies used to calculate peak demand savings<br>* 10% due to the benefits from reduced air conditioning load in lighting retrofits<br>* Overall net-to-gross ratios in the low 70's represent an improvement over the 2009 and<br>Strict eligibility requirements and improvements in the pre-approval process contributed to the improvement in net-to-gross ratios |
| | | * Though overall performance is above expectations, participation continues to decline year over year as the initiative reaches maturity<br>* 70% of province-wide resource savings persist to 2014 |

| # | Initiative | OPA Province-Wide Key Evaluation Findings |
|---|---|---|
| 10 | Direct Install Lighting | * Over 35% of the projects for 2011 included at least one CFL measure<br>* Resource savings from CFLs in the commercial sector only persist for the industry standard of 3 years<br>* Since 2009 the overall realization rate for this program has improved<br>* 2011 evaluation recorded the highest energy realization rate to date at 89.5%<br>* The hours of use values were held constant from the 2010 evaluation and continue to be the main driver of energy realization rate<br>* Lights installed in “as needed” areas (e.g., bathrooms, storage areas) were determined to have very low realization rates due to the difference in actual energy saved vs. reported savings |
| 11 | Existing Building Commissioning Incentive | * Initiative was not evaluated in 2011, no completed projects in 2011 |
| 12 | New Construction and Major Renovation Incentive | * Initiative was not evaluated in 2011 due to low uptake<br>* Assumptions used are consistent with preliminary reporting based on the 2010 Evaluation findings and consultation with the C&I Work Group (100% realization rate and 50% net-to-gross ratio) |
| 13 | Energy Audit | * The evaluation is ongoing.  The sample size for 2011 was too small to draw reliable conclusions. |
| 14 | Commercial Demand Response (part of the Residential program schedule) | * See residential demand response (#7) |
| 15 | Demand Response 3 (part of the Industrial program schedule) | * See Demand Response 3 (#20) |
| **Industrial Program** | | |
| 16 | Process & System Upgrades | * Initiative was not evaluated in 2011, no completed projects in 2011 |
| 17 | Monitoring & Targeting | * Initiative was not evaluated in 2011, no completed projects in 2011 |
| 18 | Energy Manager | * Initiative was not evaluated in 2011, no completed projects in 2011 |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | * See Efficiency: Equipment Replacement (#9) |
| 20 | Demand Response 3 | * Program performance for Tier 1 customers increased with DR-3 participants providing 75%<br>* Industrial customers outperform commercial customers by provide 84% and 76% of contracted MW, respectively<br>* Program continues to diversify but still remains heavily concentrated with less than 5% of |

| # | Initiative | OPA Province-Wide Key Evaluation Findings |
|---|---|---|
| | | * By increasing the number of contributors in each settlement account and implementation of the new baseline methodology the performance of the program is expected to increase |
| **Home Assistance Program** | | |
| 21 | Home Assistance Program | * Initiative was not evaluated in 2011 due to low uptake<br>* Business Case assumptions were used to calculate savings |
| **Pre-2011 Programs completed in 2011** | | |
| 22 | Electricity Retrofit Incentive Program | * Initiative was not evaluated<br>* Net-to-Gross ratios used are consistent with the 2010 evaluation findings (multifamily buildings 99% realization rate and 62% net-to-gross ratio and C&I buildings 77% realization rate and 52% net-to-gross ratio) |
| 23 | High Performance New Construction | * Initiative was not evaluated<br>* Net-to-Gross ratios used are consistent with the 2010 evaluation findings (realization rate of 100% and net-to-gross ratio of 50%) |
| 24 | Toronto Comprehensive | * Initiative was not evaluated<br>* Net-to-Gross ratios used are consistent with the 2010 evaluation findings |
| 25 | Multifamily Energy Efficiency Rebates | * Initiative was not evaluated<br>* Net-to-Gross ratios used are consistent with the 2010 evaluation findings |
| 26 | Data Centre Incentive Program | * Initiative was not evaluated |
| 27 | EnWin Green Suites | * Initiative was not evaluated |

**Table 5: Summarized Program Results**

| Program | Gross Savings | | | Net Savings | |
|---|---|---|---|---|---|
| | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) | | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) |
| Consumer Program Total | 621 | 1,809,983 | | 375 | 1,197,730 |
| Business Program Total | 485 | 2,006,624 | | 406 | 1,609,340 |
| Industrial Program Total | 326 | 819,662 | | 261 | 623,720 |
| Home Assistance Program Total | 0 | 0 | | 0 | 0 |
| Pre-2011 Programs completed in 2011 Total | 360 | 2,060,587 | | 188 | 1,084,690 |
| **Total OPA Contracted Province-Wide CDM Programs** | **1,792** | **6,696,856** | | **1,230** | **4,515,479** |

| # | Initiative | Realization Rate | | Gross Savings | | Net-to-Gross Ratio | | Net Savings | |
|---|---|---|---|---|---|---|---|---|---|
| | | Peak Demand Savings | Energy Savings | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) | Peak Demand Savings | Energy Savings | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) |
| **Consumer Program** | | | | | | | | | |
| 1 | Appliance Retirement | 100% | 100% | 70 | 500,087 | 51% | 51% | 35 | 250,242 |
| 2 | Appliance Exchange | 100% | 100% | 18 | 24,971 | 52% | 52% | 9 | 12,869 |
| 3 | HVAC Incentives | 100% | 100% | 514 | 955,277 | 60% | 60% | 310 | 571,421 |
| 4 | Conservation Instant Coupon Booklet | 100% | 100% | 8 | 134,486 | 115% | 113% | 9 | 149,983 |
| 5 | Bi-Annual Retailer Event | 100% | 100% | 11 | 195,161 | 113% | 110% | 12 | 213,214 |
| 6 | Retailer Co-op | - | - | 0 | 0 | - | - | 0 | 0 |
| 7 | Residential Demand Response | 0% | 0% | 0 | 0 | - | - | 0 | 0 |
| 8 | Residential New Construction | - | - | 0 | 0 | - | - | 0 | 0 |
| **Business Program** | | | | | | | | | |
| 9 | Efficiency: Equipment Replacement | 91% | 108% | 247 | 1,559,892 | 72% | 77% | 179 | 1,194,344 |
| 10 | Direct Install Lighting | 108% | 90% | 149 | 444,096 | 93% | 93% | 159 | 412,361 |
| 11 | Existing Building Commissioning Incentive | - | - | 0 | 0 | - | - | 0 | 0 |
| 12 | New Construction and Major Renovation Incentive | - | - | 0 | 0 | - | - | 0 | 0 |
| 13 | Energy Audit | - | - | 0 | 0 | - | - | 0 | 0 |
| 14 | Commercial Demand Response (part of the Residential program schedule) | 0% | 0% | 0 | 0 | - | - | 0 | 0 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | 76% | 100% | 89 | 2,636 | n/a | n/a | 67 | 2,636 |
| **Industrial Program** | | | | | | | | | |
| 16 | Process & System Upgrades | - | - | 0 | 0 | - | - | 0 | 0 |
| 17 | Monitoring & Targeting | - | - | 0 | 0 | - | - | 0 | 0 |
| 18 | Energy Manager | - | - | 0 | 0 | - | - | 0 | 0 |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | 93% | 129% | 124 | 809,669 | 73% | 76% | 90 | 613,727 |
| 20 | Demand Response 3 | 84% | 100% | 202 | 9,993 | n/a | n/a | 170 | 9,993 |
| **Home Assistance Program** | | | | | | | | | |
| 21 | Home Assistance Program | - | - | 0 | 0 | - | - | 0 | 0 |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | |
| 22 | Electricity Retrofit Incentive Program | 80% | 81% | 266 | 1,577,017 | 53% | 54% | 141 | 842,905 |
| 23 | High Performance New Construction | 100% | 100% | 94 | 483,571 | 50% | 50% | 47 | 241,785 |
| 24 | Toronto Comprehensive | - | - | 0 | 0 | - | - | 0 | 0 |
| 25 | Multifamily Energy Efficiency Rebates | - | - | 0 | 0 | - | - | 0 | 0 |
| 26 | Data Centre Incentive Program | - | - | 0 | 0 | - | - | 0 | 0 |
| 27 | EnWin Green Suites | - | - | 0 | 0 | - | - | 0 | 0 |

*Assumes demand response resources have a persistence of 1 year*

| Program | Contribution to Targets | |
| --- | --- | --- |
| | Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014 | Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh) |
| Consumer Program Total | 371 | 4,786,860 |
| Business Program Total | 302 | 6,320,656 |
| Industrial Program Total | 90 | 2,464,900 |
| Home Assistance Program Total | 0 | 0 |
| Pre-2011 Programs completed in 2011 Total | 188 | 4,338,760 |
| **Total OPA Contracted Province-Wide CDM Programs** | **952** | **17,911,176** |

| # | Initiative | Contribution to Targets | |
| --- | --- | --- | --- |
| | | Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014 | Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh) |
| **Consumer Program** | | | |
| 1 | Appliance Retirement | 34 | 1,000,362 |
| 2 | Appliance Exchange | 5 | 48,026 |
| 3 | HVAC Incentives | 310 | 2,285,684 |
| 4 | Conservation Instant Coupon Booklet | 9 | 599,933 |
| 5 | Bi-Annual Retailer Event | 12 | 852,855 |
| 6 | Retailer Co-op | 0 | 0 |
| 7 | Residential Demand Response | 0 | 0 |
| 8 | Residential New Construction | 0 | 0 |
| **Business Program** | | | |
| 9 | Efficiency: Equipment Replacement | 179 | 4,777,375 |
| 10 | Direct Install Lighting | 123 | 1,540,646 |
| 11 | Existing Building Commissioning Incentive | 0 | 0 |
| 12 | New Construction and Major Renovation Incentive | 0 | 0 |
| 13 | Energy Audit | 0 | 0 |
| 14 | Commercial Demand Response (part of the Residential program schedule) | 0 | 0 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | 0 | 2,636 |
| **Industrial Program** | | | |
| 16 | Process & System Upgrades | 0 | 0 |
| 17 | Monitoring & Targeting | 0 | 0 |
| 18 | Energy Manager | 0 | 0 |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | 90 | 2,454,907 |
| 20 | Demand Response 3 | 0 | 9,993 |
| **Home Assistance Program** | | | |
| 21 | Home Assistance Program | 0 | 0 |
| **Pre-2011 Programs completed in 2011** | | | |
| 22 | Electricity Retrofit Incentive Program | 141 | 3,371,618 |
| 23 | High Performance New Construction | 47 | 967,141 |
| 24 | Toronto Comprehensive | 0 | 0 |
| 25 | Multifamily Energy Efficiency Rebates | 0 | 0 |
| 26 | Data Centre Incentive Program | 0 | 0 |
| 27 | EnWin Green Suites | 0 | 0 |

*Assumes demand response resources have a persistence of 1 year*

## Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Yellow cells are intended for the LDC to input information to complete their OEB Reporting Template.

### Table 6: Net Peak Demand Savings at the End User Level (MW)

| Implementation Period | Annual | | | |
|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 |
| **2011 - Verified** | 1.23 | 0.99 | 0.99 | 0.95 |
| **2012** | | | | |
| **2013** | | | | |
| **2014** | | | | 0.00 |
| **Verified Net Annual Peak Demand Savings Persisting in 2014:** | | | | **0.95** |
| **Brantford Power Inc. 2014 Annual CDM Capacity Target:** | | | | **11.38** |
| **Verified Portion of Peak Demand Savings Target Achieved in 2014(%):** | | | | **8.36%** |
| **LDC Milestone submitted for 2011** | | | | **-%** |
| **Variance** | | | | |

### Table 7: Net Energy Savings at the End User Level (GWh)

| Implementation Period | Annual | | | | Cumulative |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2011-2014 |
| **2011 - Verified** | 4.52 | 4.50 | 4.50 | 4.39 | 17.91 |
| **2012** | | | | | |
| **2013** | | | | | |
| **2014** | | | | | |
| **Verified Net Cumulative Energy Savings 2011-2014:** | | | | | **17.91** |
| **Brantford Power Inc. 2011-2014 Cumulative CDM Energy Target:** | | | | | **48.92** |
| **Verified Portion of Cumulative Energy Target Achieved (%):** | | | | | **36.61%** |
| **LDC Milestone submitted for 2011** | | | | | **-%** |
| **Variance** | | | | | |

## Table P1: Province-Wide Participation

| # | Initiative | Activity Unit | Uptake/ Participation Units |
|---|---|---|---|
| **Consumer Program** | | | |
| 1 | Appliance Retirement | Appliances | 56,110 |
| 2 | Appliance Exchange | Appliances | 3,688 |
| 3 | HVAC Incentives | Equipment | 111,587 |
| 4 | Conservation Instant Coupon Booklet | Products[4] | 559,462 |
| 5 | Bi-Annual Retailer Event | Products[5] | 870,332 |
| 6 | Retailer Co-op | Products | 152 |
| 7 | Residential Demand Response | Devices | 19,577 |
| 8 | Residential New Construction | Houses | 7 |
| **Business Program** | | | |
| 9 | Efficiency: Equipment Replacement | Projects | 2,516 |
| 10 | Direct Installed Lighting | Projects | 20,297 |
| 11 | Existing Building Commissioning Incentive | Buildings | - |
| 12 | New Construction and Major Renovation Incentive | Buildings | 10 |
| 13 | Energy Audit | Audits | 103 |
| 14 | Commercial Demand Response (part of the Residential program schedule) | Devices | 264 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | Facilities | 148 |
| **Industrial Program** | | | |
| 16 | Process & System Upgrades[2] | Projects | - |
| 17 | Monitoring & Targeting[2] | Projects | - |
| 18 | Energy Manager[2 3] | Managers | - |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)[1] | Projects | 433 |
| 20 | Demand Response 3 | Facilities | 134 |
| **Home Assistance Program** | | | |
| 21 | Home Assistance Program | Homes | 46 |
| **Pre 2011 Programs Completed in 2011** | | | |
| 22 | Electricity Retrofit Incentive Program | Projects | 2,023 |
| 23 | High Performance New Construction | Projects | 145 |
| 24 | Toronto Comprehensive | Projects | 553 |
| 25 | Multifamily Energy Efficiency Rebates | Projects | 110 |
| 26 | Data Centre Incentive Program | Projects | 5 |
| 27 | EnWin Green Suites | Projects | 3 |

*[2] Results are based on completed incentive projects (see "Methodology" tab for more information)*

*[3] Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers with completed projects*

*[4] 209,693 valid coupons redeemed*

*[5] 369,446 valid coupons redeemed*

## Table P2: Province-Wide Results

| Program | Gross Savings: Incremental Peak Demand Savings (kW) | Gross Savings: Incremental Energy Savings (kWh) | | Net Savings: Incremental Peak Demand Savings (kW) | Net Savings: Incremental Energy Savings (kWh) |
|---|---|---|---|---|---|
| Consumer Program Total | 73,757 | 192,379,633 | | 49,123 | 133,519,668 |
| Business Program Total | 78,048 | 251,304,448 | | 64,594 | 198,124,227 |
| Industrial Program Total | 68,648 | 41,493,145 | | 57,099 | 31,947,577 |
| Home Assistance Program Total | 4 | 56,119 | | 2 | 39,283 |
| Pre-2011 Programs completed in 2011 Total | 87,169 | 460,822,079 | | 44,833 | 241,853,020 |
| **Total OPA Contracted Province-Wide CDM Programs** | **307,626** | **946,055,425** | | **215,651** | **605,483,775** |

| # | Initiative | Realization Rate | | Gross Savings | | Net-to-Gross Ratio | | Net Savings | |
|---|---|---|---|---|---|---|---|---|---|
| | | Peak Demand Savings | Energy Savings | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) | Peak Demand Savings | Energy Savings | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) |
| **Consumer Program** | | | | | | | | | |
| 1 | Appliance Retirement | 100% | 100% | 6,750 | 45,971,627 | 51% | 51% | 3,299 | 23,005,812 |
| 2 | Appliance Exchange | 100% | 100% | 719 | 873,531 | 51% | 51% | 371 | 450,187 |
| 3 | HVAC Incentives | 100% | 100% | 53,209 | 99,413,430 | 60% | 60% | 32,037 | 59,437,670 |
| 4 | Conservation Instant Coupon Booklet | 100% | 100% | 1,184 | 19,192,453 | 114% | 111% | 1,344 | 21,211,537 |
| 5 | Bi-Annual Retailer Event | 100% | 100% | 1,504 | 26,899,265 | 112% | 110% | 1,681 | 29,387,468 |
| 6 | Retailer Co-op | 100% | 100% | 0 | 3,917 | 68% | 68% | 0 | 2,652 |
| 7 | Residential Demand Response | n/a | n/a | 10,390 | 23,597 | n/a | n/a | 10,390 | 23,597 |
| 8 | Residential New Construction | 100% | 100% | 0 | 1,813 | 41% | 41% | 0 | 743 |
| **Business Program** | | | | | | | | | |
| 9 | Efficiency: Equipment Replacement | 106% | 91% | 34,201 | 184,070,265 | 72% | 74% | 24,467 | 136,002,258 |
| 10 | Direct Installed Lighting | 108% | 93% | 22,155 | 65,777,197 | 108% | 93% | 23,724 | 61,076,701 |
| 11 | Existing Building Commissioning Incentive | - | - | - | - | - | - | - | - |
| 12 | New Construction and Major Renovation Incentive | 50% | 50% | 247 | 823,434 | 50% | 50% | 123 | 411,717 |
| 13 | Energy Audit | - | - | - | - | - | - | - | - |
| 14 | Commercial Demand Response (part of the Residential program schedule) | n/a | n/a | 55 | 131 | n/a | n/a | 55 | 131 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | 76% | n/a | 21,390 | 633,421 | n/a | n/a | 16,224 | 633,421 |
| **Industrial Program** | | | | | | | | | |
| 16 | Process & System Upgrades | - | - | - | - | - | - | - | - |
| 17 | Monitoring & Targeting | - | - | - | - | - | - | - | - |
| 18 | Energy Manager | - | - | - | - | - | - | - | - |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | 111% | 91% | 6,372 | 38,412,408 | 72% | 75% | 4,615 | 28,866,840 |
| 20 | Demand Response 3 | 84% | n/a | 62,276 | 3,080,737 | n/a | n/a | 52,484 | 3,080,737 |
| **Home Assistance Program** | | | | | | | | | |
| 21 | Home Assistance Program | 100% | 100% | 4 | 56,119 | 70% | 70% | 2 | 39,283 |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | |
| 22 | Electricity Retrofit Incentive Program | 80% | 80% | 40,418 | 223,956,390 | 54% | 54% | 21,550 | 120,492,549 |
| 23 | High Performance New Construction | 100% | 100% | 10,197 | 52,371,183 | 49% | 49% | 5,098 | 26,185,591 |
| 24 | Toronto Comprehensive | 113% | 113% | 33,467 | 174,070,574 | 50% | 52% | 15,805 | 86,964,886 |
| 25 | Multifamily Energy Efficiency Rebates | 93% | 93% | 2,553 | 9,774,792 | 78% | 78% | 1,981 | 7,595,683 |
| 26 | Data Centre Incentive Program | 100% | 100% | 81 | 533,038 | 100% | 100% | 81 | 533,038 |
| 27 | EnWin Green Suites | 100% | 100% | 453 | 116,102 | 70% | 70% | 317 | 81,272 |

*Assumes demand response resources have a persistence of 1 year*

| Program | Contribution to Targets | |
|---|---|---|
| | Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014 | Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh) |
| Consumer Program Total | 38,405 | 534,017,835 |
| Business Program Total | 41,048 | 767,657,790 |
| Industrial Program Total | 4,613 | 118,543,019 |
| Home Assistance Program Total | 2 | 157,134 |
| Pre-2011 Programs completed in 2011 Total | 44,833 | 967,412,079 |
| **Total OPA Contracted Province-Wide CDM Programs** | **128,901** | **2,387,787,856** |

| # | Initiative | Contribution to Targets | |
|---|---|---|---|
| | | Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014 | Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh) |
| **Consumer Program** | | | |
| 1 | Appliance Retirement | 3,160 | 91,903,303 |
| 2 | Appliance Exchange | 181 | 1,930,651 |
| 3 | HVAC Incentives | 32,037 | 237,750,681 |
| 4 | Conservation Instant Coupon Booklet | 1,344 | 84,846,148 |
| 5 | Bi-Annual Retailer Event | 1,681 | 117,549,874 |
| 6 | Retailer Co-op | 0 | 10,607 |
| 7 | Residential Demand Response | 0 | 23,597 |
| 8 | Residential New Construction | 0 | 2,973 |
| **Business Program** | | | |
| 9 | Efficiency: Equipment Replacement | 24,438 | 543,856,392 |
| 10 | Direct Installed Lighting | 16,486 | 221,520,977 |
| 11 | Existing Building Commissioning Incentive | - | - |
| 12 | New Construction and Major Renovation Incentive | 123 | 1,646,869 |
| 13 | Energy Audit | - | - |
| 14 | Commercial Demand Response (part of the Residential program schedule) | 0 | 131 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | 0 | 633,421 |
| **Industrial Program** | | | |
| 16 | Process & System Upgrades | - | - |
| 17 | Monitoring & Targeting | - | - |
| 18 | Energy Manager | - | - |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | 4,613 | 115,462,282 |
| 20 | Demand Response 3 | 0 | 3,080,737 |
| **Home Assistance Program** | | | |
| 21 | Home Assistance Program | 2 | 157,134 |
| **Pre-2011 Programs completed in 2011** | | | |
| 22 | Electricity Retrofit Incentive Program | 21,550 | 481,970,197 |
| 23 | High Performance New Construction | 5,098 | 104,742,366 |
| 24 | Toronto Comprehensive | 15,805 | 347,859,545 |
| 25 | Multifamily Energy Efficiency Rebates | 1,981 | 30,382,733 |
| 26 | Data Centre Incentive Program | 81 | 2,132,152 |
| 27 | EnWin Green Suites | 317 | 325,086 |

*Assumes demand response resources have a persistence of 1 year*

## Summary - Provincial Progress

### Table P3: Province-Wide Net Peak Demand Savings at the End User Level (MW)

| Implementation Period | Annual | | | |
|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 |
| **2011** | 215.7 | 136.4 | 135.7 | 128.9 |
| **2012** | | | | |
| **2013** | | | | |
| **2014** | | | | |
| **Verified Net Annual Peak Demand Savings in 2014:** | | | | **128.9** |
| **2014 Annual CDM Capacity Target** | | | | **1,330** |
| **Verified Peak Demand Savings Target Achieved - 2011 (%):** | | | | **9.69%** |

### Table P4: Province-Wide Net Energy Savings at the End-User Level (GWh)

| Implementation Period | Annual | | | | Cumulative |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2011-2014 |
| **2011** | 605.5 | 601.6 | 599.6 | 580.9 | 2,388 |
| **2012** | | | | | 0 |
| **2013** | | | | | 0 |
| **2014** | | | | | 0 |
| **Verified Net Cumulative Energy Savings 2011-2014:** | | | | | **2,388** |
| **2011-2014 Cumulative CDM Energy Target:** | | | | | **6,000** |
| **Verified Portion of Energy Target Achieved - 2011 (%):** | | | | | **39.79%** |

## METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

### EQUATIONS:

**PRESCRIPTIVE MEASURES/PROJECTS:**

**Gross Savings =** Activity * Per Unit Assumption

**Net Savings =** Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

**ENGINEERED/CUSTOM PROJECTS:**

**Gross Savings =** Reported Savings * Realization Rate

**Net Savings =** Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

**DEMAND RESPONSE:**

**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio

**Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| **Consumer Program** | | | | |
| 1 | Appliance Retirement | Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection | Savings are considered to begin in the year the appliance is picked up. | **Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| 2 | Appliance Exchange | When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput | Savings are considered to begin in the year that the exchange event occurred | |
| 3 | HVAC Incentives | Results directly attributed to LDC based on customer postal code | Savings are considered to begin in the year that the installation occurred | |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 4 | Conservation Instant Coupon Booklet | LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput | Savings are considered to begin in the year in which the coupon was redeemed. | **Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives. |
| 5 | Bi-Annual Retailer Event | Results are allocated based on average of 2008 & 2009 residential throughput | Savings are considered to begin in the year in which the event occurs. | |
| 6 | Retailer Co-op | When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput. | Savings are considered to begin in the year of the home visit and installation date. | **Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives. |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 7 | Residential Demand Response | Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists | Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. | **Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated. |
| 8 | Residential New Construction | Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case. | Savings are considered to begin in the year of the project completion date. | **Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| **Business Program** | | | | |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 9 | Efficiency: Equipment Replacement | Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping | Savings are considered to begin in the year of the actual project completion date on the iCON CRM system. | **Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). |
| | | **Additional Note:** project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses. | | |
| 10 | Direct Installed Lighting | Results are directly attributed to LDC based on the LDC specified on the work order | Savings are considered to begin in the year of the actual project completion date. | **Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net). |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 11 | Existing Building Commissioning Incentive | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year of the actual project completion date. | **Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 12 | New Construction and Major Renovation Incentive | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups) | Savings are considered to begin in the year of the actual project completion date. | |
| 13 | Energy Audit | No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application | Savings are considered to begin in the year of the audit date. | **Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 14 | Commercial Demand Response (part of the Residential program schedule) | Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists | Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. | **Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated. |
| 15 | Demand Response 3 (part of the Industrial program schedule) | Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level. | Savings are considered to begin in the year in which the contributor signed up to participate in demand response. | **Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource. |
| **Industrial Program** | | | | |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 16 | Process & System Upgrades | Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year in which the incentive project was completed. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 17 | Monitoring & Targeting | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year in which the incentive project was completed. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 18 | Energy Manager | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping | Savings are considered to begin in the year of the actual project completion date on the iCON CRM system. | **Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 20 | Demand Response 3 | Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level. | Savings are considered to begin in the year in which the contributor signed up to participate in demand response. | **Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource. |
| **Home Assistance Program** | | | | |
| 21 | Home Assistance Program | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case. | Savings are considered to begin in the year in which the measures were installed. | **Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| **Pre-2011 Programs completed in 2011** | | | | |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 22 | Electricity Retrofit Incentive Program | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | Savings are considered to begin in the year in which a project was completed. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports). |
| 23 | High Performance New Construction | Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | Savings are considered to begin in the year in which a project was completed. | |
| 24 | Toronto Comprehensive | Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | | |
| 25 | Multifamily Energy Efficiency Rebates | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results |
| 26 | Data Centre Incentive Program | Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation | Savings are considered to begin in the year in which a project was completed. | |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| 27 | EnWin Green Suites | Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | | from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports). |

**ERII Sector (C&I vs. Industrial Mapping)**

| Building Type | Sector |
|---|---|
| Agribusiness - Cattle Farm | C&I |
| Agribusiness - Dairy Farm | C&I |
| Agribusiness - Greenhouse | C&I |
| Agribusiness - Other | C&I |
| Agribusiness - Other,Mixed-Use - Office/Retail | C&I |
| Agribusiness - Other,Office,Retail,Warehouse | C&I |
| Agribusiness - Other,Office,Warehouse | C&I |
| Agribusiness - Poultry | C&I |
| Agribusiness - Poultry,Hospitality - Motel | C&I |
| Agribusiness - Swine | C&I |
| Convenience Store | C&I |
| Education - College / Trade School | C&I |
| Education - College / Trade School,Multi-Residential - Condominium | C&I |
| Education - College / Trade School,Multi-Residential - Rental Apartment | C&I |
| Education - College / Trade School,Retail | C&I |
| Education - Primary School | C&I |
| Education - Primary School,Education - Secondary School | C&I |
| Education - Primary School,Multi-Residential - Rental Apartment | C&I |
| Education - Primary School,Not-for-Profit | C&I |
| Education - Secondary School | C&I |
| Education - University | C&I |
| Education - University,Office | C&I |
| Hospital/Healthcare - Clinic | C&I |
| Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building | C&I |
| Hospital/Healthcare - Clinic,Industrial | C&I |
| Hospital/Healthcare - Clinic,Retail | C&I |
| Hospital/Healthcare - Long-term Care | C&I |
| Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building | C&I |
| Hospital/Healthcare - Medical Building | C&I |
| Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail | C&I |
| Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office | C&I |
| Hospitality - Hotel | C&I |
| Hospitality - Hotel,Restaurant - Dining | C&I |
| Hospitality - Motel | C&I |
| Industrial | Industrial |
| Mixed-Use - Office/Retail | C&I |
| Mixed-Use - Office/Retail,Industrial | Industrial |
| Mixed-Use - Office/Retail,Mixed-Use - Other | C&I |
| Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse | C&I |
| Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail | C&I |

| | |
|---|---|
| Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse | C&I |
| Mixed-Use - Office/Retail,Office,Warehouse | C&I |
| Mixed-Use - Office/Retail,Retail | C&I |
| Mixed-Use - Office/Retail,Warehouse | C&I |
| Mixed-Use - Office/Retail,Warehouse,Industrial | Industrial |
| Mixed-Use - Other | C&I |
| Mixed-Use - Other,Industrial | Industrial |
| Mixed-Use - Other,Not-for-Profit,Office | C&I |
| Mixed-Use - Other,Office | C&I |
| Mixed-Use - Other,Other: Please specify | C&I |
| Mixed-Use - Other,Retail,Warehouse | C&I |
| Mixed-Use - Other,Warehouse | C&I |
| Mixed-Use - Residential/Retail | C&I |
| Mixed-Use - Residential/Retail,Multi-Residential - Condominium | C&I |
| Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment | C&I |
| Mixed-Use - Residential/Retail,Retail | C&I |
| Multi-Residential - Condominium | C&I |
| Multi-Residential - Condominium,Multi-Residential - Rental Apartment | C&I |
| Multi-Residential - Condominium,Other: Please specify | C&I |
| Multi-Residential - Rental Apartment | C&I |
| Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit | C&I |
| Multi-Residential - Rental Apartment,Not-for-Profit | C&I |
| Multi-Residential - Rental Apartment,Warehouse | C&I |
| Multi-Residential - Social Housing Provider | C&I |
| Multi-Residential - Social Housing Provider,Industrial | C&I |
| Multi-Residential - Social Housing Provider,Not-for-Profit | C&I |
| Not-for-Profit | C&I |
| Not-for-Profit,Office | C&I |
| Not-for-Profit,Other: Please specify | C&I |
| Not-for-Profit,Warehouse | C&I |
| Office | C&I |
| Office,Industrial | Industrial |
| Office,Other: Please specify | C&I |
| Office,Other: Please specify,Warehouse | C&I |
| Office,Restaurant - Dining | C&I |
| Office,Restaurant - Dining,Industrial | Industrial |
| Office,Retail | C&I |
| Office,Retail,Industrial | C&I |
| Office,Retail,Warehouse | C&I |
| Office,Warehouse | C&I |
| Office,Warehouse,Industrial | Industrial |
| Other: Please specify | C&I |
| Other: Please specify,Industrial | Industrial |
| Other: Please specify,Retail | C&I |
| Other: Please specify,Warehouse | C&I |

| | |
|---|---|
| Restaurant - Dining | C&I |
| Restaurant - Dining,Retail | C&I |
| Restaurant - Quick Serve | C&I |
| Restaurant - Quick Serve,Retail | C&I |
| Retail | C&I |
| Retail,Industrial | Industrial |
| Retail,Warehouse | C&I |
| Warehouse | C&I |
| Warehouse,Industrial | Industrial |

## Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

| Local Distribution Company | Allocation |
|---|---|
| Algoma Power Inc. | 0.2% |
| Atikokan Hydro Inc. | 0.0% |
| Attawapiskat Power Corporation | 0.0% |
| Bluewater Power Distribution Corporation | 0.6% |
| Brant County Power Inc. | 0.2% |
| Brantford Power Inc. | 0.7% |
| Burlington Hydro Inc. | 1.4% |
| Cambridge and North Dumfries Hydro Inc. | 1.0% |
| Canadian Niagara Power Inc. | 0.5% |
| Centre Wellington Hydro Ltd. | 0.1% |
| Chapleau Public Utilities Corporation | 0.0% |
| COLLUS Power Corporation | 0.3% |
| Cooperative Hydro Embrun Inc. | 0.0% |
| E.L.K. Energy Inc. | 0.2% |
| Enersource Hydro Mississauga Inc. | 3.9% |
| ENTEGRUS | 0.6% |
| ENWIN Utilities Ltd. | 1.6% |
| Erie Thames Powerlines Corporation | 0.4% |
| Espanola Regional Hydro Distribution Corporation | 0.1% |
| Essex Powerlines Corporation | 0.7% |
| Festival Hydro Inc. | 0.3% |
| Fort Albany Power Corporation | 0.0% |
| Fort Frances Power Corporation | 0.1% |
| Greater Sudbury Hydro Inc. | 1.0% |
| Grimsby Power Inc. | 0.2% |
| Guelph Hydro Electric Systems Inc. | 0.9% |
| Haldimand County Hydro Inc. | 0.4% |
| Halton Hills Hydro Inc. | 0.5% |
| Hearst Power Distribution Company Limited | 0.1% |
| Horizon Utilities Corporation | 4.0% |
| Hydro 2000 Inc. | 0.0% |

| | |
|---|---|
| Hydro Hawkesbury Inc. | 0.1% |
| Hydro One Brampton Networks Inc. | 2.8% |
| Hydro One Networks Inc. | 30.0% |
| Hydro Ottawa Limited | 5.6% |
| Innisfil Hydro Distribution Systems Limited | 0.4% |
| Kashechewan Power Corporation | 0.0% |
| Kenora Hydro Electric Corporation Ltd. | 0.1% |
| Kingston Hydro Corporation | 0.5% |
| Kitchener-Wilmot Hydro Inc. | 1.6% |
| Lakefront Utilities Inc. | 0.2% |
| Lakeland Power Distribution Ltd. | 0.2% |
| London Hydro Inc. | 2.7% |
| Middlesex Power Distribution Corporation | 0.1% |
| Midland Power Utility Corporation | 0.1% |
| Milton Hydro Distribution Inc. | 0.6% |
| Newmarket - Tay Power Distribution Ltd. | 0.7% |
| Niagara Peninsula Energy Inc. | 1.0% |
| Niagara-on-the-Lake Hydro Inc. | 0.2% |
| Norfolk Power Distribution Inc. | 0.3% |
| North Bay Hydro Distribution Limited | 0.5% |
| Northern Ontario Wires Inc. | 0.1% |
| Oakville Hydro Electricity Distribution Inc. | 1.5% |
| Orangeville Hydro Limited | 0.2% |
| Orillia Power Distribution Corporation | 0.3% |
| Oshawa PUC Networks Inc. | 1.2% |
| Ottawa River Power Corporation | 0.2% |
| Parry Sound Power Corporation | 0.1% |
| Peterborough Distribution Incorporated | 0.7% |
| PowerStream Inc. | 6.6% |
| PUC Distribution Inc. | 0.9% |
| Renfrew Hydro Inc. | 0.1% |
| Rideau St. Lawrence Distribution Inc. | 0.1% |
| Sioux Lookout Hydro Inc. | 0.1% |
| St. Thomas Energy Inc. | 0.3% |
| Thunder Bay Hydro Electricity Distribution Inc. | 0.9% |
| Tillsonburg Hydro Inc. | 0.1% |
| Toronto Hydro-Electric System Limited | 12.8% |
| Veridian Connections Inc. | 2.4% |
| Wasaga Distribution Inc. | 0.2% |
| Waterloo North Hydro Inc. | 1.0% |
| Welland Hydro-Electric System Corp. | 0.4% |
| Wellington North Power Inc. | 0.1% |
| West Coast Huron Energy Inc. | 0.1% |
| Westario Power Inc. | 0.5% |
| Whitby Hydro Electric Corporation | 0.9% |
| Woodstock Hydro Services Inc. | 0.3% |

## Reporting Glossary

**Annual:** the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

**Cumulative Energy Savings:** represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

**End-User Level:** resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

**Free-ridership:** the percentage of participants who would have implemented the program measure or practice in the absence of the program.

**Incremental:** the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

**Initiative:** a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

**Net-to-Gross Ratio:** The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

**Net Energy Savings (MWh):** energy savings attributable to conservation and demand management activities net of free-riders, etc.

**Net Peak Demand Savings (MW):** peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

**Program:** a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

**Realization Rate:** A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

**Settlement Account:** the grouping of demand response facilities (contributors) into one contractual agreement

**Spillover:** Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

**Unit:** for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

# APPENDIX G

# LRAM THIRD PARTY REPORT

BURMAN ENERGY
CONSULTANTS GROUP INC.

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# BRANTFORD POWER INC.

# LRAM & LRAMVA SUPPORT

**MARCH 27, 2013**

**PREPARED BY: BART BURMAN, MBA, BA.SC. P.ENG., PRESIDENT**

# 1. LRAM

**LRAM History**

From 2005 to the end of 2010, distributors delivered CDM programs either through approved distribution rate funding by way of the third installment of their incremental market adjusted revenue requirement (“MARR”), or through contracts with the OPA. Some distributors received incremental distribution rate funding separate from MARR. To promote the participation in and the delivery of CDM programs by distributors, the Board made available an LRAM regardless of whether the CDM programs were funded by the OPA or through distribution rates.

In preparation of this document, Burman Energy performed this analysis in compliance with **Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003** with specific reference to the following:

> ***13.6 LRAM & Shared Savings Mechanism for Pre-CDM Code Activities***
>
> *The Board notes that the Filing Requirements for Transmission and Distribution Applications state the following:*
>
> > *Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the OPA between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.*
>
> *The 2008 CDM Guidelines state as follows: “lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time”. The intent of the LRAM in the 2008 CDM Guidelines was to keep electricity distributors revenue neutral for CDM activities implemented by the distributor during the years in which its rates were set using the incentive regulation mechanism, and that future LRAM claims should be unnecessary once a distributor rebases and updates its load forecast.*
>
> *The Board therefore expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.*

In compliance with the last paragraph above, since Brantford Power has not updated their load forecast since 2008, Burman Energy recommends an LRAM claim of $118,455.70. This is consistent with Brantford Powers OEB decision EB-2011-0147 dated April 19, 2012. Specifically,

> *Persisting impacts of 2005-2008 programs and 2008 lost revenues*
>
> *Board staff noted that Brantford's rates were last rebased in 2008. Board staff also noted that the CDM Guidelines state the following with respect to LRAM claims:*
>
> > *Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time7.*
>
> *In cases in which it was clear in the application or settlement agreement that an adjustment for CDM was not being incorporated into the load forecast specifically because of an expectation that an LRAM application would address the issue, and if this approach was accepted by the Board, then Board staff would agree that an LRAM application is appropriate. Board staff submitted that Brantford may want to highlight in its reply whether the issue of an LRAM application was addressed in its cost of service application.*

| Initiative Name | Net Summer Peak Demand Savings (kW) | Net Energy Savings (kWh) | Gross Summer Peak Demand Savings (kW) | Gross Energy Savings (kWh) | 2011 LRAM |
|---|---|---|---|---|---|
| **TOTAL 2005 - 2010 PROGRAM PERSISTENCE** | **3,395.64** | **13,147,196** | **5,113.27** | **21,419,144** | **$ 118,455.70** |

The above table represents LRAM calculations for persistence of 2006-2010 programs in 2011 only.

Brantford Power should also be eligible for the 2006 – 2010 program persistence into 2012 and 2013 as well. However, the Board also notes that claims for persistence into future years or for years where claims are deemed premature should be excluded. As such, Burman Energy recommends including only the amounts identified above with the latitude to submit for additional LRAM claims for 2006 – 2010 program persistence into 2012 and 2013 in future submissions.

## 2. LRAMVA

With specific reference to the following:

***13.2 LRAM Mechanism for 2011- 2014***

*The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account ("LRAMVA") to capture, at the customer rate-class level, the difference between the following:*

*i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and*

*ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).*

*Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third part for each year of the CDM program (i.e., 2011 to 2014) in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The variance calculated from this comparison results in a credit or debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor's Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.*

Burman Energy has prepared the following LRAMVA tables, representing the kWh and kW values to be applied in consideration of the variance account baseline from 2011 to 2013. These values are prepared as approximate amounts that have been included in Brantford Power's 2013 load forecast. The results were calculated to align with Brantford's overall CDM target achievement as specified in their OEB Strategy ED-2003-0060 filing and addendum dated November 1, 2010 and June 13, 2011 respectively.

The 2013 LRAMVA amount of 14,676 MWh and 231 MW has been allocated by year based on the OEB assigned 2011-2014 CDM targets and is consistent with subsequent CDM Strategy submitted by Brantford Power and acknowledged by the OEB.

In addition to the projected MWh savings amounts for each year, annual persistence into subsequent years has also been calculated in the table below. These amounts reflect actual 2011 CDM results and 2011 persistence into 2012 and 2013, 2012 projected program results and projected persistence of 2012 into 2013, and 2013 projected program results.

| Annual Savings by Year (MWh) - Includes Actuals for 2011 & 2011 Persistence | | | | | |
|---|---|---|---|---|---|
| **Program Year** | **2011** | **2012** | **2013** | **2014** | **TOTAL** |
| **2011** | 4,516 | 4,503 | 4,499 | 4,394 | **17,911** |
| **2012** | | 5,281 | 5,281 | 5,281 | **15,843** |
| **2013** | | | 4,896 | 4,896 | **9,792** |
| **2014** | | | | 5,373 | **5,373** |
| | | | | | |
| **Total** | **4,516** | **9,784** | **14,676** | **19,944** | **48,920** |

The LRAMVA amounts have been allocated to the customer classes based on the OPA's kW and kWh results and the resulting allocation shown in the table below.

| | **2011 Peak Demand Savings (kW)** | **2011 Energy Savings (kWh)** | | **% allocated by program** |
|---|---|---|---|---|
| Consumer Program Total | 375 | 1197730 | | 27% |
| Business Program Total | 406 | 1609340 | | 36% |
| Industrial Program Total | 261 | 623720 | | 38% |
| Home Assistance Program Total | 0 | 0 | | |
| Pre-2011 Programs completed in 2011 Total (allocated to Industrial program) | 188 | 1084690 | | |
| | **1230** | **4515479** | | **100%** |

*Source: 2011 Final Annual Report Data_Brantford Power Inc.(1).xls*

| Rate Class | LRAMVA kWh Total | Allocation per rate class | Total LRAMVA kWh allocated per class | Total LRAMVA kW allocated per class |
|---|---|---|---|---|
| | | | | |
| **Residential** | | 27% | 3,893 | |
| **GS < 50kW** | | 36% | 5,231 | |
| **GS 50kW to 4,999kW** | | 38% | 5,553 | 231.00 |
| **TOTAL** | **14,676** | **100%** | **14,676** | **231.00** |

# SUPPORTING ATTACHMENTS

**Brantford Power. LRAM CALCULATIONS**

**OPA Conservation & Demand Management Programs**

**Initiative Results at End-User Level**

| Initiative Name | Program Year | Results Status | 2011 Net Summer Peak Demand Savings (kW) | 2011 Net Energy Savings (kWh) | 2011 Gross Summer Peak Demand Savings (kW) | 2011 Gross Energy Savings (kWh) | Load Forecast CDM Component | 2010 Rate (effective May 1) | 2011 Rate (effective May 1) | 2011 LRAM |
|---|---|---|---|---|---|---|---|---|---|---|
| **2005 - 2010 PROGRAM PERSISTENCE** | | | | | | | | | | |
| **Residential** | | | | | | | | kWh | kWh | |
| Secondary Fridge Retirement Pilot | 2006 | Final | 8.95 | 39,485 | 9.94 | 43,872 | | 0.0137 | 0.0137 | $ 540.94 |
| Cool & Hot Savings Rebate | | | | | | | | | | |
| | 2006 | Final | 90.33 | 97,471 | 109.84 | 123,478 | | 0.0137 | 0.0137 | $ 1,335.36 |
| | 2007 | Final | 105.78 | 158,539 | 222.04 | 311,387 | | 0.0137 | 0.0137 | $ 2,171.99 |
| Every Kilowatt Counts | | | | | | | | 0.0137 | 0.0137 | |
| | 2006 | Final | 29.83 | 326,087 | 33.14 | 362,319 | | 0.0137 | 0.0137 | $ 4,467.40 |
| | 2007 | Final | 33.35 | 938,731 | 47.00 | 1,275,402 | | 0.0137 | 0.0137 | $ 12,860.62 |
| Great Refrigerator Roundup | | | | | | | | | | |
| | 2007 | Final | 20.14 | 176,265 | 49.35 | 434,764 | | 0.0137 | 0.0137 | $ 2,414.83 |
| | 2008 | Final | 44.84 | 406,678 | 84.88 | 749,990 | | 0.0137 | 0.0137 | $ 5,571.49 |
| | 2009 | Final | 59.50 | 404,978 | 114.51 | 760,183 | | 0.0137 | 0.0137 | $ 5,548.20 |
| | 2010 | Final | 79.27 | 488,312 | 159.96 | 924,174 | | 0.0137 | 0.0137 | $ 6,689.88 |
| Social Housing – Pilot | 2007 | Final | 10.16 | 86,375 | 10.16 | 86,375 | | 0.0137 | 0.0137 | $ 1,183.34 |
| Cool Savings Rebate Program | | | | | | | | | | |
| | 2008 | Final | 106.45 | 168,039 | 184.80 | 292,528 | | 0.0137 | 0.0137 | $ 2,302.14 |
| | 2009 | Final | 138.77 | 210,706 | 317.47 | 493,155 | | 0.0137 | 0.0137 | $ 2,886.68 |
| | 2010 | Final | 208.41 | 317,555 | 471.75 | 740,519 | | 0.0137 | 0.0137 | $ 4,350.50 |
| Every Kilowatt Counts Power Savings Event | | | | | | | | 0.0137 | 0.0137 | $ - |
| | 2008 | Final | 44.45 | 849,299 | 105.52 | 2,105,022 | | 0.0137 | 0.0137 | $ 11,635.39 |
| | 2009 | Final | 36.49 | 351,183 | 97.21 | 903,101 | | 0.0137 | 0.0137 | $ 4,811.21 |
| | 2010 | Final | 11.53 | 119,678 | 28.31 | 293,451 | | 0.0137 | 0.0137 | $ 1,639.59 |
| peaksaver® | | | | | | | | | | |
| | 2007 | Final | 5.87 | 0 | 6.52 | 0 | | 0.0137 | 0.0137 | $ - |
| | 2008 | Final | 223.17 | 4,463 | 247.97 | 4,959 | | 0.0137 | 0.0137 | $ 61.15 |
| | 2009 | Final | 242.50 | 443 | 269.44 | 493 | | 0.0137 | 0.0137 | $ 6.07 |
| | 2010 | Final | 147.36 | 669 | 163.73 | 743 | | 0.0137 | 0.0137 | $ 9.16 |
| Summer Sweepstakes | 2008 | Final | 138.39 | 344,217 | 178.37 | 443,658 | | 0.0137 | 0.0137 | $ 4,715.77 |
| **TOTAL Residential** | | | **1,785.54** | **5,489,175** | **2,911.92** | **10,349,573** | | | | **$ 75,201.69** |
| **General Service <50kW** | | | | | | | | kWh | kWh | |
| High Performance New Construction | | | | | | | | | | |
| | 2008 | Final | 3.02 | 2,551 | 4.32 | 3,645 | | 0.0064 | 0.0064 | $ 16.33 |
| | 2009 | Final | 32.86 | 74,908 | 46.94 | 107,011 | | 0.0064 | 0.0064 | $ 479.41 |
| | 2010 | Final | 103.87 | 236,826 | 148.39 | 338,324 | | 0.0064 | 0.0064 | $ 1,515.69 |
| Power Savings Blitz | | | | | | | | | | |
| | 2008 | Final | 0.00 | 0 | 0.00 | 0 | | 0.0064 | 0.0064 | $ - |
| | 2009 | Final | 704.42 | 2,748,183 | 741.49 | 2,892,824 | | 0.0064 | 0.0064 | $ 17,588.37 |
| | 2010 | Final | 65.57 | 201,231 | 66.24 | 203,263 | | 0.0064 | 0.0064 | $ 1,287.88 |
| Multifamily Energy Efficiency Rebates | 2010 | Final | 15.31 | 180,733 | 20.03 | 245,353 | | 0.0064 | 0.0064 | $ 1,156.69 |
| **TOTAL GS < 50kW** | | | **925.06** | **3,444,433** | **1,027.40** | **3,790,420** | | | | **$ 22,044.37** |
| **General Service >50kW to 4,999kW** | | | | | | | | kW | kW | |
| Electricity Retrofit Incentive Program | | | | | | | | | | |
| | 2007 | Final | 5.28 | 14,654 | 5.86 | 16,282 | | 2.5770 | 2.5816 | $ 163.33 |
| | 2008 | Final | 60.62 | 308,271 | 104.52 | 531,502 | | 2.5770 | 2.5816 | $ 1,876.90 |
| | 2009 | Final | 362.05 | 2,440,227 | 572.73 | 3,872,045 | | 2.5770 | 2.5816 | $ 11,209.22 |
| | 2010 | Final | 257.11 | 1,450,436 | 490.84 | 2,859,320 | | 2.5770 | 2.5816 | $ 7,960.18 |
| **TOTAL GS > 50kW to 4,000kW** | | | **685.05** | **4,213,589** | **1,173.95** | **7,279,150** | | | | **$ 21,209.63** |
| **TOTAL 2005 - 2010 PROGRAM PERSISTENCE** | | | **3,395.64** | **13,147,196** | **5,113.27** | **21,419,144** | | | | **$ 118,455.70** |

**Brantford Power LRAMVA CALCULATIONS**
**OPA Conservation & Demand Management Programs**
**Initiative Results at End-User Level**

| | MW | MWh |
|---|---|---|
| Brantfords Target | 11.38 | 48,920 |

| 2011 Final OPA Report | 2011 Net Peak Demand Savings (kW) | 2011 Net Energy Savings (kWh) | % allocated by program |
|---|---|---|---|
| **Consumer Program Total** | 375 | 1,197,730 | 27% |
| **Business Program Total** | 406 | 1,609,340 | 36% |
| **Industrial Program Total** | 261 | 623,720 | 38% |
| **Home Assistance Program Total** | 0 | - | |
| **Pre-2011 Programs completed in 2011 Total** | 188 | 1,084,690 | |
| | **1230** | **4,515,479** | **100%** |

**Annual Savings by Year (MWh) - Includes Actuals for 2011 & 2011 Persistance**

| Program Year | | 2011 | 2012 | 2013 | 2014 | TOTAL |
|---|---|---|---|---|---|---|
| | **2011** | 4,516 | 4,503 | 4,499 | 4,394 | **17,911** |
| | **2012** | | 5,281 | 5,281 | 5,281 | **15,843** |
| | **2013** | | | 4,896 | 4,896 | **9,792** |
| | **2014** | | | | 5,373 | **5,373** |
| **Strategy Total** | | **4,516** | **9,784** | **14,676** | **19,944** | **48,920** |

| Updated Strategy Target | MWh - Annual Savings by Year | % of target achieved by year |
|---|---|---|
| **2011** | 4,516 | 9% |
| **2012** | 9,784 | 20% |
| **2013** | 14,676 | 30% |
| **2014** | 19,944 | 41% |
| | **48,920** | **100%** |

| Rate Class | LRAMVA kWh Total | Allocation per rate class | Total LRAMVA kWh | Total LRAMVA kW allocated per |
|---|---|---|---|---|
| **Residential** | | 27% | 3,893 | |
| **GS < 50kW** | | 36% | 5,231 | |
| **GS 50kW to 4,999kW** | | 38% | 5,553 | 231.00 |
| **TOTAL** | **14,676** | **100%** | **14,676** | **231.00** |

| Initiative Name | Program Year | Results Status | Net Summer Peak Demand Savings (kW) | Net Energy Savings (kWh) | Gross Summer Peak Demand Savings (kW) | Gross Energy Savings (kWh) |
|---|---|---|---|---|---|---|
| **Pre-2011 PROGRAMS COMPLETED IN 2011** | | | | | | |
| **General Service <50kW** | | | | | | |
| High Performance New Construction | | Final | 47.00 | 241,785 | 94.00 | 483,571 |
| **GENERAL SERVICE <50kW TOTAL** | | | **47.00** | **241,785** | **94.00** | **483,571** |
| **General Service >50kW to 4,999kW** | | | | | | |
| Electricity Retrofit Incentive | | Final | 141.00 | 842,905 | 266.00 | 1,577,017 |
| **GENERAL SERVICE >50kW to 4,999kW TOTAL** | | | **141.00** | **842,905** | **266.00** | **1,577,017** |
| **TOTAL LRAM - PRE-2011 PROGRAMS COMPLETED IN 2010** | | | **188.00** | **1,084,690** | **360.00** | **2,060,588** |
| **2011 OPA PROGRAM RESULTS** | | | | | | |
| **Residential Service** | | | | | | |
| Appliance Retirement | 2011 | Final | 35.00 | 250,242 | 70.00 | 500,087 |
| Appliance Exchange | 2011 | Final | 9.00 | 12,869 | 18.00 | 24,971 |
| HVAC Incentives | 2011 | Final | 310.00 | 571,421 | 514.00 | 955,277 |
| Conservation Instant Coupon Booklet | 2011 | Final | 9.00 | 149,983 | 8.00 | 134,486 |
| Bi-Annual Retailer Event | 2011 | Final | 12.00 | 213,214 | 11.00 | 195,161 |
| Residential Demand Response | 2011 | Final | 0.00 | 0 | 0.00 | 0 |
| **RESIDENTIAL TOTAL** | | | **375.00** | **1,197,729** | **621.00** | **1,809,982** |
| **General Service <50kW** | | | | | | |
| Efficiency: Equipment Replacement | 2011 | Final | 179.00 | 1,194,344 | 247.00 | 1,559,892 |
| Direct Install Lighting | 2011 | Final | 159.00 | 412,361 | 149.00 | 444,096 |
| Commercial Demand Response | 2011 | Final | 0.00 | 0 | 0.00 | 0 |
| Demand Response 3 | 2011 | Final | 67.00 | 2,636 | 89.00 | 2,636 |
| **GENERAL SERVICE <50kW TOTAL** | | | **405.00** | **1,609,341** | **485.00** | **2,006,624** |
| **General Service 50 to 4,999 kW** | | | | | | |
| Efficiency: Equipment Replacement (Industrial) | 2011 | Final | 90.00 | 613,727 | 124.00 | 809,669 |
| Demand Response 3 | 2011 | Final | 170.00 | 9,993 | 202.00 | 9,993 |
| **GENERAL SERVICE 50 to 4,999 kW** | | | **260.00** | **623,720** | **326.00** | **819,662** |
| **TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS** | | | **1,040.0** | **3,430,790** | **1,432.0** | **4,636,268** |

| | | | | | |
|---|---|---|---|---|---|
| **TOTAL LRAM - PRE-2011 PROGRAMS COMPLETED IN 2010** | | 188.00 | 1,084,690 | 360.00 | 2,060,588 |
| **TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS** | | 1,040.0 | 3,430,790 | 1,432.0 | 4,636,268 |
| | | **1,228.00** | **4,515,480** | **1,792.00** | **6,696,856** |

## Table 1: Participation[1]

| # | Initiative | Unit | Uptake/ Participation Units |
|---|---|---|---|
| **Consumer Program** | | | |
| 1 | Appliance Retirement | Appliances | 607 |
| 2 | Appliance Exchange | Appliances | 81 |
| 3 | HVAC Incentives | Equipment | 1,092 |
| 4 | Conservation Instant Coupon Booklet | Products | 3,702 |
| 5 | Bi-Annual Retailer Event | Products | 6,314 |
| 6 | Retailer Co-op | Products | 0 |
| 7 | Residential Demand Response | Devices | 0 |
| 8 | Residential New Construction | Houses | 0 |
| **Business Program** | | | |
| 9 | Efficiency: Equipment Replacement | Projects | 20 |
| 10 | Direct Install Lighting | Projects | 102 |
| 11 | Existing Building Commissioning Incentive | Buildings | 0 |
| 12 | New Construction and Major Renovation Incentive | Buildings | 0 |
| 13 | Energy Audit | Audits | 0 |
| 14 | Commercial Demand Response (part of the Residential program schedule) | Devices | 0 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | Facilities | 2 |
| **Industrial Program** | | | |
| 16 | Process & System Upgrades | Projects[2] | 0 |
| 17 | Monitoring & Targeting | Projects[3] | 0 |
| 18 | Energy Manager | Managers[2 3] | 0 |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | Projects | 12 |
| 20 | Demand Response 3 | Facilities | 2 |
| **Home Assistance Program** | | | |
| 21 | Home Assistance Program | Homes | 0 |
| **Pre 2011 Programs Completed in 2011** | | | |
| 22 | Electricity Retrofit Incentive Program | Projects | 29 |
| 23 | High Performance New Construction | Projects | 1 |
| 24 | Toronto Comprehensive | Projects | 0 |
| 25 | Multifamily Energy Efficiency Rebates | Projects | 0 |
| 26 | Data Centre Incentive Program | Projects | 0 |
| 27 | EnWin Green Suites | Projects | 0 |

*[1] Please see "Methodology" tab for more information regarding attributing savings to LDCs*

*[2] Results are based on completed incentive projects (see "Methodology" tab for more information)*

*[3] Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

**Table 5: Summarized Program Results**

| Program | Gross Savings | | | Net Savings | | Contribution to Targets | |
|---|---|---|---|---|---|---|---|
| | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) | | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) | Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014 | Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh) |
| Consumer Program Total | 621 | 1,809,983 | | 375 | 1,197,730 | 371 | 4,786,860 |
| Business Program Total | 485 | 2,006,624 | | 406 | 1,609,340 | 302 | 6,320,656 |
| Industrial Program Total | 326 | 819,662 | | 261 | 623,720 | 90 | 2,464,900 |
| Home Assistance Program Total | 0 | 0 | | 0 | 0 | 0 | 0 |
| Pre-2011 Programs completed in 2011 Total | 360 | 2,060,587 | | 188 | 1,084,690 | 188 | 4,338,760 |
| **Total OPA Contracted Province-Wide CDM Programs** | **1,792** | **6,696,856** | | **1,230** | **4,515,479** | **952** | **17,911,176** |

| # | Initiative | Realization Rate | | Gross Savings | | Net-to-Gross Ratio | | Net Savings | | Contribution to Targets | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Peak Demand Savings | Energy Savings | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) | Peak Demand Savings | Energy Savings | Incremental Peak Demand Savings (kW) | Incremental Energy Savings (kWh) | Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014 | Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh) |
| **Consumer Program** | | | | | | | | | | | |
| 1 | Appliance Retirement | 100% | 100% | 70 | 500,087 | 51% | 51% | 35 | 250,242 | 34 | 1,000,362 |
| 2 | Appliance Exchange | 100% | 100% | 18 | 24,971 | 52% | 52% | 9 | 12,869 | 5 | 48,026 |
| 3 | HVAC Incentives | 100% | 100% | 514 | 955,277 | 60% | 60% | 310 | 571,421 | 310 | 2,285,684 |
| 4 | Conservation Instant Coupon Booklet | 100% | 100% | 8 | 134,486 | 115% | 113% | 9 | 149,983 | 9 | 599,933 |
| 5 | Bi-Annual Retailer Event | 100% | 100% | 11 | 195,161 | 113% | 110% | 12 | 213,214 | 12 | 852,855 |
| 6 | Retailer Co-op | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 7 | Residential Demand Response | 0% | 0% | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 8 | Residential New Construction | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| **Business Program** | | | | | | | | | | | |
| 9 | Efficiency: Equipment Replacement | 91% | 108% | 247 | 1,559,892 | 72% | 77% | 179 | 1,194,344 | 179 | 4,777,375 |
| 10 | Direct Install Lighting | 108% | 90% | 149 | 444,096 | 93% | 93% | 159 | 412,361 | 123 | 1,540,646 |
| 11 | Existing Building Commissioning Incentive | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 12 | New Construction and Major Renovation Incentive | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 13 | Energy Audit | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 14 | Commercial Demand Response (part of the Residential program schedule) | 0% | 0% | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 15 | Demand Response 3 (part of the Industrial program schedule) | 76% | 100% | 89 | 2,636 | n/a | n/a | 67 | 2,636 | 0 | 2,636 |
| **Industrial Program** | | | | | | | | | | | |
| 16 | Process & System Upgrades | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 17 | Monitoring & Targeting | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 18 | Energy Manager | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | 93% | 129% | 124 | 809,669 | 73% | 76% | 90 | 613,727 | 90 | 2,454,907 |
| 20 | Demand Response 3 | 84% | 100% | 202 | 9,993 | n/a | n/a | 170 | 9,993 | 0 | 9,993 |
| **Home Assistance Program** | | | | | | | | | | | |
| 21 | Home Assistance Program | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| **Pre-2011 Programs completed in 2011** | | | | | | | | | | | |
| 22 | Electricity Retrofit Incentive Program | 80% | 81% | 266 | 1,577,017 | 53% | 54% | 141 | 842,905 | 141 | 3,371,618 |
| 23 | High Performance New Construction | 100% | 100% | 94 | 483,571 | 50% | 50% | 47 | 241,785 | 47 | 967,141 |
| 24 | Toronto Comprehensive | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 25 | Multifamily Energy Efficiency Rebates | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 26 | Data Centre Incentive Program | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |
| 27 | EnWin Green Suites | - | - | 0 | 0 | - | - | 0 | 0 | 0 | 0 |

*Assumes demand response resources have a persistence of 1 year*

## METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

### EQUATIONS:

**PRESCRIPTIVE MEASURES/PROJECTS:**

**Gross Savings =** Activity * Per Unit Assumption

**Net Savings =** Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

**ENGINEERED/CUSTOM PROJECTS:**

**Gross Savings =** Reported Savings * Realization Rate

**Net Savings =** Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

**DEMAND RESPONSE:**

**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio

**Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| **Consumer Program** | | | | |
| 1 | Appliance Retirement | Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection | Savings are considered to begin in the year the appliance is picked up. | **Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |
| 2 | Appliance Exchange | When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput | Savings are considered to begin in the year that the exchange event occurred | |
| 3 | HVAC Incentives | Results directly attributed to LDC based on customer postal code | Savings are considered to begin in the year that the installation occurred | **Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives. |
| 4 | Conservation Instant Coupon Booklet | LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput | Savings are considered to begin in the year in which the coupon was redeemed. | |
| 5 | Bi-Annual Retailer Event | Results are allocated based on average of 2008 & 2009 residential throughput | Savings are considered to begin in the year in which the event occurs. | |
| 6 | Retailer Co-op | When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput. | Savings are considered to begin in the year of the home visit and installation date. | **Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives. |
| 7 | Residential Demand Response | Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists | Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. | **Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated. |
| 8 | Residential New Construction | Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case. | Savings are considered to begin in the year of the project completion date. | **Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| **Business Program** | | | | |
| 9 | Efficiency: Equipment Replacement | Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping | Savings are considered to begin in the year of the actual project completion date on the iCON CRM system. | **Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). |
| | | **Additional Note:** project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses. | | |
| 10 | Direct Installed Lighting | Results are directly attributed to LDC based on the LDC specified on the work order | Savings are considered to begin in the year of the actual project completion date. | **Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net). |
| 11 | Existing Building Commissioning Incentive | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year of the actual project completion date. | **Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 12 | New Construction and Major Renovation Incentive | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups) | Savings are considered to begin in the year of the actual project completion date. | |
| 13 | Energy Audit | No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application | Savings are considered to begin in the year of the audit date. | **Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 14 | Commercial Demand Response (part of the Residential program schedule) | Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists | Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. | **Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated. |
| 15 | Demand Response 3 (part of the Industrial program schedule) | Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level. | Savings are considered to begin in the year in which the contributor signed up to participate in demand response. | **Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource. |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| **Industrial Program** | | | | |
| 16 | Process & System Upgrades | Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year in which the incentive project was completed. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 17 | Monitoring & Targeting | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year in which the incentive project was completed. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 18 | Energy Manager | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011. | Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). |
| 19 | Efficiency: Equipment Replacement Incentive (part of the C&I program schedule) | Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping | Savings are considered to begin in the year of the actual project completion date on the iCON CRM system. | **Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). |
| 20 | Demand Response 3 | Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level. | Savings are considered to begin in the year in which the contributor signed up to participate in demand response. | **Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource. |
| **Home Assistance Program** | | | | |
| 21 | Home Assistance Program | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case. | Savings are considered to begin in the year in which the measures were installed. | **Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. |

| # | Initiative | Attributing Savings to LDCs | Savings 'start' Date | Calculating Resource Savings |
|---|---|---|---|---|
| **Pre-2011 Programs completed in 2011** | | | | |
| 22 | Electricity Retrofit Incentive Program | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | Savings are considered to begin in the year in which a project was completed. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports). |
| 23 | High Performance New Construction | Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | Savings are considered to begin in the year in which a project was completed. | |
| 24 | Toronto Comprehensive | Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | | |
| 25 | Multifamily Energy Efficiency Rebates | Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | Savings are considered to begin in the year in which a project was completed. | **Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports). |
| 26 | Data Centre Incentive Program | Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation | | |
| 27 | EnWin Green Suites | Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation | | |

**Final 2011 Results**
Brantford Power Inc.

**Net Annual Peak Demand Savings (MW)**

| Program | Initiative | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Consumer | Appliance Exchange | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Consumer | Appliance Retirement | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Consumer | Bi-Annual Retailer Event | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 |
| Consumer | Conservation Instant Coupon Booklet | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Consumer | HVAC Incentives | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Consumer | Residential Demand Response | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Consumer | Retailer Co-op | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| C&I | Demand Response 3 (part of the Industrial program schedu | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| C&I | Direct Install Lighting | 0.16 | 0.16 | 0.16 | 0.12 | 0.12 | 0.12 | 0.05 | 0.05 | 0.05 | 0.05 |
| C&I | Efficiency: Equipment Replacement | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.11 | 0.11 |
| C&I | Commercial Demand Response (part of the Residential pro | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Industrial | Demand Response 3 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Industrial | Efficiency: Equipment Replacement Incentive (part of the C | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Pre-2011 Programs Completed in 2011 | Electricity Retrofit Incentive Program | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 |
| Pre-2011 Programs Completed in 2011 | High Performance New Construction | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| **Grand Total** | | **1.34** | **0.99** | **0.99** | **0.95** | **0.93** | **0.91** | **0.83** | **0.83** | **0.76** | **0.76** |

**Net Annual Energy Savings (MWh)**

| Program | Initiative | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Consumer | Appliance Exchange | 13 | 13 | 13 | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| Consumer | Appliance Retirement | 250 | 250 | 250 | 250 | 169 | 0 | 0 | 0 | 0 | 0 |
| Consumer | Bi-Annual Retailer Event | 213 | 213 | 213 | 213 | 195 | 175 | 132 | 131 | 170 | 54 |
| Consumer | Conservation Instant Coupon Booklet | 150 | 150 | 150 | 150 | 139 | 127 | 103 | 102 | 125 | 57 |
| Consumer | HVAC Incentives | 571 | 571 | 571 | 571 | 571 | 571 | 571 | 571 | 571 | 571 |
| Consumer | Residential Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Consumer | Retailer Co-op | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C&I | Demand Response 3 (part of the Industrial program schedu | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C&I | Direct Install Lighting | 412 | 412 | 408 | 308 | 308 | 308 | 126 | 124 | 124 | 124 |
| C&I | Efficiency: Equipment Replacement | 1,194 | 1,194 | 1,194 | 1,194 | 1,194 | 1,194 | 1,194 | 1,194 | 711 | 711 |
| C&I | Commercial Demand Response (part of the Residential pro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Industrial | Demand Response 3 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Industrial | Efficiency: Equipment Replacement Incentive (part of the C | 614 | 614 | 614 | 614 | 614 | 614 | 614 | 614 | 574 | 574 |
| Pre-2011 Programs Completed in 2011 | Electricity Retrofit Incentive Program | 843 | 843 | 843 | 843 | 843 | 843 | 843 | 843 | 843 | 843 |
| Pre-2011 Programs Completed in 2012 | High Performance New Construction | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 | 242 |
| **Grand Total** | | **4,516** | **4,503** | **4,499** | **4,394** | **4,274** | **4,074** | **3,824** | **3,821** | **3,359** | **3,176** |

| Exhibit | Tab | Schedule | Appendix | Contents |
|---|---|---|---|---|
| **5 – Cost of Capital and Rate of Return** | | | | |
| | 1 | 1 | | Overview |
| | | 2 | | Capital Structure Deemed & Actual |
| | | | A | Copy of Promissory Note with City of Brantford |

## OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2013 test years.

### Capital Structure

BPI has a current deemed capital structure of 4% short term debt with a return of 4.47%, 56% long-term debt with a return of 5.88%, and 40% equity with a return of 8.57%. BPI arrived at this capital structure in 2010, following a capital structure transition mandated by the Board. Based on the Board's Decision in BPI's 2008 Cost of Service distribution rate Application (EB-2007-0698), BPI's capital structure was 49.3% long term debt, 4% short term debt and 46.7% equity. In 2009, BPI took another step in its capital structure transition. Long term debt was 52.7%, short term debt 4%, and equity was 43.3%. In 2010, BPI finalized its transition to the Board's deemed structure of 56% long term debt, 4% short term debt, and 40% equity. Throughout these transitions, the rates of return on each component of capital structure remained the same. BPI has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 5.17%, 4% Short Term Debt with a return of 2.07%, and 40% Equity with a return of 8.98%.

### Return on Equity

BPI is requesting a return on equity ("ROE") for the 2013 Test Year of 8.98% in accordance with the Cost of Capital Parameter Updates for 2013 Cost of Service Applications issued by the OEB on February 14, 2013.

## ***<u>COST OF DEBT</u>***

### Long Term Debt

BPI is requesting a return on Long Term Debt for the 2013 Test Year of 5.17%. BPI is currently paying a rate of 5.87% on its promissory note with the Corporation of the City of Brantford renewed at January 27, 2011.

A copy of the promissory note is attached as Appendix A in this Exhibit. In addition to this rate on affiliated debt, BPI is paying rates varying from 4.71% to 4.97% on existing Long Term Loans negotiated with the Royal Bank of Canada and rates varying from 3.46% to 5.14% for existing debentures negotiated with Ontario Infrastructure and Lands Corporation (OILC). BPI's loans are outlined in Table 5.1 below.

# Table 5.1 – Actual Weighted Average Cost of Long-Term Debt

## Appendix 2-OB
## Debt Instruments

This table must be completed for the required years of all historical years, the bridge year and the test year.

**Year** 2008

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory note | The Corporation of the City of Brantford | Affiliated | Fixed Rate | February 1, 2006 | 5 | $ 24,189,168 | 6.25% | $1,511,823.00 | |
| 2 | Powerline Municipal Transformer Station Borrowings | Royal Bank | Third-Party | Fixed Rate | January 31, 2006 | 15 | $ 5,381,000 | 4.71% | $ 253,445.10 | |
| 3 | Tier 2 Capital Project Borrowing | Royal Bank | Third-Party | Fixed Rate | June 13, 2006 | 10 | $ 1,012,000 | 4.97% | $ 50,296.40 | |
| 4 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2007 | 25 | $ 2,370,718 | 5.14% | $ 121,854.93 | |
| Total | | | | | | | $ 32,952,886 | 0.05879 | $1,937,419.43 | |

## Debt Instruments

This table must be completed for the required years of all historical years, the bridge year and the test year.

**Year** 2009

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory note | The Corporation of the City of Brantford | Affiliated | Fixed Rate | February 1, 2006 | 5 | $ 24,189,168 | 6.25% | $1,511,823.00 | |
| 2 | Powerline Municipal Transformer Station Borrowings | Royal Bank | Third-Party | Fixed Rate | January 31, 2006 | 15 | $ 5,061,000 | 4.71% | $ 238,373.10 | |
| 3 | Tier 2 Capital Project Borrowing | Royal Bank | Third-Party | Fixed Rate | June 13, 2006 | 10 | $ 909,000 | 4.97% | $ 45,177.30 | |
| 4 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2007 | 25 | $ 2,318,871 | 5.14% | $ 119,189.98 | |
| 5 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 1, 2010 | 25 | $ 2,400,000 | 0.95% | $ 22,800.00 | |
| 6 | Smart meter borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | November 18, 2009 | 15 | $ 1,451,000 | 1.75% | $ 25,392.50 | |
| Total | | | | | | | $ 36,329,039 | 0.05403 | $1,962,755.88 | |

## Debt Instruments

This table must be completed for the required years of all historical years, the bridge year and the test year.

**Year** 2010

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory note | The Corporation of the City of Brantford | Affiliated | Fixed Rate | February 1, 2006 | 5 | $ 24,189,168 | 6.25% | $1,511,823.00 | |
| 2 | Powerline Municipal Transformer Station Borrowings | Royal Bank | Third-Party | Fixed Rate | January 31, 2006 | 15 | $ 4,724,000 | 4.71% | $ 222,500.40 | |
| 3 | Tier 2 Capital Project Borrowing | Royal Bank | Third-Party | Fixed Rate | June 13, 2006 | 10 | $ 801,000 | 4.97% | $ 39,809.70 | |
| 4 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2007 | 25 | $ 2,264,325 | 5.14% | $ 116,386.29 | |
| 5 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 1, 2010 | 40 | $ 4,800,000 | 4.95% | $ 237,600.00 | |
| 6 | Smart meter borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | November 18, 2009 | 3 | $ 4,751,000 | 1.54% | $ 73,165.40 | |
| Total | | | | | | | $ 41,529,493 | 0.05301 | $2,201,284.79 | |

## Appendix 2-OB
## Debt Instruments

This table must be completed for the required years of all historical years, the bridge year and the test year.

**Year** 2011

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory note | The Corporation of the City of Brantford | Affiliated | Fixed Rate | February 1, 2011 | 5 | $ 24,189,168 | 5.87% | $1,419,904.16 | |
| 2 | Powerline Municipal Transformer Station Borrowings | Royal Bank | Third-Party | Fixed Rate | January 31, 2006 | 15 | $ 4,369,000 | 4.71% | $ 205,779.90 | |
| 3 | Tier 2 Capital Project Borrowing | Royal Bank | Third-Party | Fixed Rate | June 13, 2006 | 10 | $ 686,000 | 4.97% | $ 34,094.20 | |
| 4 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2007 | 25 | $ 2,206,939 | 5.14% | $ 113,436.65 | |
| 5 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 1, 2010 | 40 | $ 4,760,374 | 4.95% | $ 235,638.51 | |
| 6 | Smart meter borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | November 18, 2009 | 3 | $ 5,301,000 | 1.75% | $ 92,767.50 | |
| Total | | | | | | | $ 41,512,481 | 0.05063 | $2,101,620.91 | |

**Debt Instruments**

This table must be completed for the required years of all historical years, the bridge year and the test year.

**Year** 2012

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory note | The Corporation of the City of Brantford | Affiliated | Fixed Rate | February 1, 2011 | 5 | $ 24,189,168 | 5.87% | $1,419,904.16 | |
| 2 | Powerline Municipal Transformer Station B | Royal Bank | Third-Party | Fixed Rate | January 31, 2006 | 15 | $ 3,994,000 | 4.71% | $ 188,117.40 | |
| 3 | Tier 2 Capital Project Borrowing | Royal Bank | Third-Party | Fixed Rate | June 13, 2006 | 10 | $ 564,000 | 4.97% | $ 28,030.80 | |
| 4 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2007 | 25 | $ 2,146,565 | 5.14% | $ 110,333.44 | |
| 5 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 1, 2010 | 40 | $ 4,718,762 | 4.95% | $ 233,578.72 | |
| 6 | Smart meter borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | November 18, 2009 | 15 | $ 4,378,708 | 1.75% | $ 76,627.40 | |
| 7 | Smart meter borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | November 18, 2009 | 15 | $ 1,152,292 | 3.46% | $ 39,869.29 | |
| 8 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2012 | 30 | $ 333,333 | 3.90% | $ 13,000.00 | |
| Total | | | | | | | $ 41,476,828 | 0.05086 | $2,109,461.21 | |

**Debt Instruments**

This table must be completed for the required years of all historical years, the bridge year and the test year.

**Year** 2013

| Row | Description | Lender | Affiliated or Third-Party Debt? | Fixed or Variable-Rate? | Start Date | Term (years) | Principal ($) | Rate (%) (Note 2) | Interest ($) (Note 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Promissory note | The Corporation of the City of Brantford | Affiliated | Fixed Rate | February 1, 2011 | 5 | $ 24,189,168 | 5.87% | $1,419,904.16 | |
| 2 | Powerline Municipal Transformer Station B | Royal Bank | Third-Party | Fixed Rate | January 31, 2006 | 15 | $ 3,596,000 | 4.71% | $ 169,371.60 | |
| 3 | Tier 2 Capital Project Borrowing | Royal Bank | Third-Party | Fixed Rate | June 13, 2006 | 10 | $ 435,000 | 4.97% | $ 21,619.50 | |
| 4 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2007 | 25 | $ 2,083,048 | 5.14% | $ 107,068.67 | |
| 5 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 1, 2010 | 40 | $ 4,675,065 | 4.95% | $ 231,415.72 | |
| 6 | Smart meter borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | November 18, 2009 | 15 | $ 5,245,003 | 3.46% | $ 181,477.10 | |
| 7 | General borrowings | Ontario Infrastructure & Lands Corporation | Third-Party | Fixed Rate | December 3, 2012 | 30 | $ 3,932,125 | 3.90% | $ 153,352.88 | |
| Total | | | | | | | $ 44,155,409 | 0.05173 | $2,284,209.63 | |

For greater accuracy in the calculation of its 2012 weighted average cost of capital and interest costs, BPI has adjusted three principal amounts in Table 5.1 to reflect the timing of changes in financing arrangements within 2012. The true principal amounts in these agreements are outlined in Table 5.2, along with the calculations used to adjust them for inclusion in Table 5.1. Specifically, these adjustments were made to reflect that BPI's $5.531M smart meter borrowing was a construction advance 1.75% for 9.5 months of 2012, and was converted to a debenture at 3.46% for the remaining 2.5 months. Additionally, an adjustment was made to reflect the fact that the 2012 General Borrowings Arrangement with OILC for $4.0M was only present for one month of 2012.

## Table 5.2 - Principal Amounts for 2012 OILC Agreements

| Description | Year Applied to | Debt Holder | True Principal | Months Valid | Adjusted Principal | Rate% | Interest Cost |
|---|---|---|---|---|---|---|---|
| | | | (A) | (B) | (C )=(A)/12*(B) | (D) | (E )=(C )*(D) |
| Smart meter borrowings | 2012 | Ontario Infrastructure & Lands Corporation | $ 5,531,000.00 | 9.5 | 4,378,708 | 1.75% | 76,627 |
| Smart meter borrowings | 2012 | Ontario Infrastructure & Lands Corporation | $ 5,531,000.00 | 2.5 | 1,152,292 | 3.46% | 39,869 |
| General borrowings | 2012 | Ontario Infrastructure & Lands Corporation | $ 4,000,000.00 | 1.0 | 333,333 | 3.90% | 13,000 |

### Affiliated Debt

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

### Third-Party Debt

BPI also holds two borrowings from Royal Bank of Canada. The first is the Powerline MTS Loan, issued January 31, 2006 at a rate of 4.71%. The principal remaining on this loan in 2008 was $5.381M, and has decreased yearly as BPI has made payments against this loan. The principal amount for 2013 is $3.596M.

The second is the Tier Two loan for BPI's 2006 Mayfair Voltage Conversion project, completed in 2006. This is a 10 year loan at 4.97% taken out June 2006. In 2008 principal remaining was 1.012M. BPI has made yearly payments against this interest. For 2013, the principal amount is $435,000.

BPI has various borrowings with the OILC. The first of these is the 2007 General Borrowings 25 year loan taken out in December 2007 at 5.14% for the 2007 Capital Plan.

In 2009 and 2010, BPI took out additional financing from OILC. On December 15, 2009, a construction advance for 2009 Capital projects, worth $2.4M, was taken out at a short term average rate of 0.95%. An additional $2.4M was advanced to BPI on December 1, 2010. These two advances were combined and converted to debenture on December 1, 2010 for a total loan of

$4.8M at 4.95% for a 40-year term. BPI has made yearly payments against this principal. For 2013, the principal amount is $4.7M.

On November 18 2009, OILC also issued a Construction Advance of $1.451M at 0.95% short term rate to BPI for its smart metering program. This was increased to a $4.751M advance at 1.54% in December 2010, to 5.301M at 1.75% in December 2011. On October 1 2012, the $5.531M loan was debentured at a rate of 3.46% for a 15 year term. Taking into consideration payments towards the principal of this loan, the principal for 2013 is $5.2 M. On Dec 3 2012, BPI signed a $4.0M 30-year loan at 3.9% with OILC for its 2012 Capital projects. Taking into consideration payments towards the principal amount, the principal outstanding in 2013 is $3.9M. BPI does not plan to add any long-term debt in 2013.

**Short Term Debt**

BPI is requesting a return on Short Term Debt for the 2013 Test year of 2.07% in accordance with the Cost of Capital Parameter Updates for 2013 Cost of Service Applications.

**Rate Base and Rate of Return**

Table 5.1 of Exhibit 5, Tab 1, Schedule 1 details BPI's rate base, debt/equity ratios and, rates of return, for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, and 2012 Bridge and 2013 Test Year Forecast.

# CAPITAL STRUCTURE

## Table 5.3 - Capital Structure 2008

### Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | Application | | | | |
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 49.3% | | $34,331,469 | 5.88% | $2,018,471 |
| 2 | Short-term Debt | 4.00% | (1) | $2,785,515 | 4.47% | $124,513 |
| 3 | **Total Debt** | 53.3% | | $37,116,983 | 5.77% | $2,142,984 |
| | **Equity** | | | | | |
| 4 | Common Equity | 46.7% | | $32,520,884 | 8.57% | $2,787,040 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 46.7% | | $32,520,884 | 8.57% | $2,787,040 |
| 7 | **Total** | 100.0% | | $69,637,867 | 7.08% | $4,930,024 |

## Table 5.4: Capital Structure 2009

### Appendix 2-OA
### Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | Application | | | | |
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 52.7% | | $37,462,433 | 5.40% | $2,023,990 |
| 2 | Short-term Debt | 4.00% | (1) | $2,843,448 | 4.47% | $127,102 |
| 3 | **Total Debt** | 56.7% | | $40,305,881 | 5.34% | $2,151,092 |
| | **Equity** | | | | | |
| 4 | Common Equity | 43.3% | | $30,780,329 | 8.57% | $2,637,874 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 43.3% | | $30,780,329 | 8.57% | $2,637,874 |
| 7 | **Total** | 100.0% | | $71,086,210 | 6.74% | $4,788,966 |

## Table 5.5 - Capital Structure 2010

### Appendix 2-OA
### Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | **Application** | | | | |
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.0% | | $41,280,072 | 5.30% | $2,188,064 |
| 2 | Short-term Debt | 4.00% | (1) | $2,948,577 | 4.47% | $131,801 |
| 3 | **Total Debt** | 60.0% | | $44,228,648 | 5.25% | $2,319,866 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $29,485,766 | 8.57% | $2,526,930 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $29,485,766 | 8.57% | $2,526,930 |
| 7 | **Total** | 100.0% | | $73,714,414 | 6.58% | $4,846,796 |

## Table 5.6 - Capital Structure 2011

### Appendix 2-OA
### Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | **Application** | | | | |
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.0% | | $42,333,493 | 5.06% | $2,143,186 |
| 2 | Short-term Debt | 4.00% | (1) | $3,023,821 | 4.47% | $135,165 |
| 3 | **Total Debt** | 60.0% | | $45,357,314 | 5.02% | $2,278,350 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.0% | | $30,238,209 | 8.57% | $2,591,415 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $30,238,209 | 8.57% | $2,591,415 |
| 7 | **Total** | 100.0% | | $75,595,523 | 6.44% | $4,869,765 |

## Table 5.7 - Capital Structure 2012

### Appendix 2-OA
### Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | Application | | | | |
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $42,568,495 | 5.09% | $2,164,982 |
| 2 | Short-term Debt | 4.00% | (1) | $3,040,607 | 4.47% | $135,915 |
| 3 | **Total Debt** | 60.0% | | $45,609,102 | 5.04% | $2,300,897 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $30,406,068 | 8.57% | $2,605,800 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $30,406,068 | 8.57% | $2,605,800 |
| 7 | **Total** | 100.0% | | $76,015,169 | 6.45% | $4,906,697 |

## Table 5.8 - Capital Structure 2013 Test

### Appendix 2-OA
### Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

| Line No. | Particulars | Capitalization Ratio | | | Cost Rate | Return |
|---|---|---|---|---|---|---|
| | | Application | | | | |
| | | (%) | | ($) | (%) | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | | $44,123,571 | 5.17% | $2,282,563 |
| 2 | Short-term Debt | 4.00% | (1) | $3,151,684 | 2.07% | $65,240 |
| 3 | **Total Debt** | 60.0% | | $47,275,254 | 4.97% | $2,347,802 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | | $31,516,836 | 8.98% | $2,830,212 |
| 5 | Preferred Shares | | | $ - | | $ - |
| 6 | **Total Equity** | 40.0% | | $31,516,836 | 8.98% | $2,830,212 |
| 7 | **Total** | 100.0% | | $78,792,090 | 6.57% | $5,178,014 |

## Table 5.9 – Capital Structure Rate Base Calculations

### 2008- Board Approved

| Description | Deemed Portion | Effective Rate |
|---|---|---|
| Long-Term Debt | 49.33% | 6.04% |
| Short-Tern Debt | 4.00% | 4.47% |
| Return On Equity | 46.67% | 8.57% |
| **Weighted Debt Rate** | | 6.23% |
| **Regulated Rate of Return** | | 7.15% |

### WORKING CAPITAL ALLOWANCE FOR 2008

| Distribution Expenses | | $ |
|---|---|---|
| Distribution Expenses - Operation | | 998,220 |
| Distribution Expenses - Maintenance | | 1,725,334 |
| Billing and Collecting | | 2,107,836 |
| Community Relations | | 127,331 |
| Administrative and General Expenses | | 2,548,053 |
| Taxes Other than Income Taxes | | 12,298 |
| **Total Eligible Distribution Expenses** | | **7,519,072** |
| Power Supply Expenses | | 73,121,800 |
| **Total Working Capital Expenses** | | 80,640,872 |
| Working Capital Allowance @ | 15.00% | 12,096,131 |

### RATE BASE CALCULATION FOR 2008

| | |
|---|---|
| Fixed Assets Opening Balance 2008 | 56,563,352 |
| Fixed Assets Closing Balance 2008 | 58,448,249 |
| **Average Fixed Asset Balance for 2008** | 57,505,801 |
| Working Capital Allowance | 12,096,131 |
| **Rate Base** | 69,601,931 |
| Regulated Rate of Return | 7.15% |
| **Regulated Return on Capital** | 4,979,435 |
| Deemed Interest Expense | 2,196,796 |
| Deemed Return on Equity | 2,782,639 |

# Table 5.9 - Capital Structure Rate Base Calculations (CONTINUED)

## 2008

| Description | Deemed Portion | Effective Rate |
|---|---|---|
| Long-Term Debt | 49.30% | 5.88% |
| Short-Tern Debt | 4.00% | 4.47% |
| Return On Equity | 46.70% | 8.57% |
| **Weighted Debt Rate** | | 5.77% |
| **Regulated Rate of Return** | | 7.08% |

## 2009

| Description | Deemed Portion | Effective Rate |
|---|---|---|
| Long-Term Debt | 52.70% | 5.40% |
| Short-Tern Debt | 4.00% | 4.47% |
| Return On Equity | 43.30% | 8.57% |
| **Weighted Debt Rate** | | 5.34% |
| **Regulated Rate of Return** | | 6.74% |

## WORKING CAPITAL ALLOWANCE FOR 2008

| Distribution Expenses | | $ |
|---|---|---|
| Distribution Expenses - Operation | | 1,018,908 |
| Distribution Expenses - Maintenance | | 1,757,147 |
| Billing and Collecting | | 1,978,917 |
| Community Relations | | 113,237 |
| Administrative and General Expenses | | 2,825,788 |
| Taxes Other than Income Taxes | | 124,265 |
| **Total Eligible Distribution Expenses** | | **7,818,261** |
| Power Supply Expenses | | 74,148,841 |
| **Total Working Capital Expenses** | | 81,967,102 |
| Working Capital Allowance @ | 15.00% | 12,295,065 |

## WORKING CAPITAL ALLOWANCE FOR 2009

| Distribution Expenses | | $ |
|---|---|---|
| Distribution Expenses - Operation | | 1,057,112 |
| Distribution Expenses - Maintenance | | 1,723,356 |
| Billing and Collecting | | 2,205,690 |
| Community Relations | | 127,829 |
| Administrative and General Expenses | | 2,614,082 |
| Taxes Other than Income Taxes | | 161,699 |
| **Total Eligible Distribution Expenses** | | **7,889,768** |
| Power Supply Expenses | | 72,025,901 |
| **Total Working Capital Expenses** | | 79,915,669 |
| Working Capital Allowance @ | 15.00% | 11,987,350 |

## RATE BASE CALCULATION FOR 2008

| | |
|---|---|
| Fixed Assets Opening Balance 2008 | 56,401,586 |
| Fixed Assets Closing Balance 2008 | 58,284,018 |
| **Average Fixed Asset Balance for 2008** | 57,342,802 |
| Working Capital Allowance | 12,295,065 |
| **Rate Base** | 69,637,867 |
| Regulated Rate of Return | 7.08% |
| **Regulated Return on Capital** | 4,930,024 |
| Deemed Interest Expense | 2,142,984 |
| Deemed Return on Equity | 2,787,040 |

## RATE BASE CALCULATION FOR 2009

| | |
|---|---|
| Fixed Assets Opening Balance 2009 | 58,284,018 |
| Fixed Assets Closing Balance 2009 | 59,913,702 |
| **Average Fixed Asset Balance for 2008** | 59,098,860 |
| Working Capital Allowance | 11,987,350 |
| **Rate Base** | 71,086,210 |
| Regulated Rate of Return | 6.74% |
| **Regulated Return on Capital** | 4,788,966 |
| Deemed Interest Expense | 2,151,092 |
| Deemed Return on Equity | 2,637,874 |

## Table 5.9 – Capital Structure Rate Base Calculations (CONTINUED)

**2010**

| Description | Deemed Portion | Effective Rate |
|---|---|---|
| Long-Term Debt | 56.00% | 5.30% |
| Short-Tern Debt | 4.00% | 4.47% |
| Return On Equity | 40.00% | 8.57% |
| **Weighted Debt Rate** | | 5.25% |
| **Regulated Rate of Return** | | 6.58% |

**2011**

| Description | Deemed Portion | Effective Rate |
|---|---|---|
| Long-Term Debt | 56.00% | 5.06% |
| Short-Tern Debt | 4.00% | 4.47% |
| Return On Equity | 40.00% | 8.57% |
| **Weighted Debt Rate** | | 5.02% |
| **Regulated Rate of Return** | | 6.44% |

**WORKING CAPITAL ALLOWANCE FOR 2010**

| Distribution Expenses | | |
|---|---|---|
| Distribution Expenses - Operation | | 1,008,391 |
| Distribution Expenses - Maintenance | | 1,681,173 |
| Billing and Collecting | | 2,166,453 |
| Community Relations | | 131,379 |
| Administrative and General Expenses | | 2,971,323 |
| Taxes Other than Income Taxes | | 35,508 |
| **Total Eligible Distribution Expenses** | | **7,994,228** |
| Power Supply Expenses | | 77,201,485 |
| **Total Working Capital Expenses** | | 85,195,713 |
| Working Capital Allowance @ | 15.00% | 12,779,357 |

**WORKING CAPITAL ALLOWANCE FOR 2011**

| Distribution Expenses | | |
|---|---|---|
| Distribution Expenses - Operation | | 1,076,343 |
| Distribution Expenses - Maintenance | | 1,456,583 |
| Billing and Collecting | | 2,045,182 |
| Community Relations | | 115,623 |
| Administrative and General Expenses | | 2,318,604 |
| Taxes Other than Income Taxes | | 7,734 |
| **Total Eligible Distribution Expenses** | | **7,020,069** |
| Power Supply Expenses | | 82,340,938 |
| **Total Working Capital Expenses** | | 89,361,008 |
| Working Capital Allowance @ | 15.00% | 13,404,151 |

**RATE BASE CALCULATION FOR 2010**

| | |
|---|---|
| Fixed Assets Opening Balance 2010 | 59,913,702 |
| Fixed Assets Closing Balance 2010 | 61,956,412 |
| **Average Fixed Asset Balance for 2009** | 60,935,057 |
| Working Capital Allowance | 12,779,357 |
| **Rate Base** | 73,714,414 |
| Regulated Rate of Return | 6.58% |
| **Regulated Return on Capital** | 4,846,796 |
| Deemed Interest Expense | 2,319,866 |
| Deemed Return on Equity | 2,526,930 |

**RATE BASE CALCULATION FOR 2011**

| | |
|---|---|
| Fixed Assets Opening Balance 2011 | 61,956,412 |
| Fixed Assets Closing Balance 2011 | 62,426,332 |
| **Average Fixed Asset Balance for 2010** | 62,191,372 |
| Working Capital Allowance | 13,404,151 |
| **Rate Base** | 75,595,523 |
| Regulated Rate of Return | 6.44% |
| **Regulated Return on Capital** | 4,869,765 |
| Deemed Interest Expense | 2,278,350 |
| Deemed Return on Equity | 2,591,415 |

# Table 5.9 – Capital Structure Rate Base Calculations (CONTINUED)

**2012**

| Description | Deemed Portion | Effective Rate |
|---|---|---|
| Long-Term Debt | 56.00% | 5.09% |
| Short-Tern Debt | 4.00% | 4.47% |
| Return On Equity | 40.00% | 8.57% |
| **Weighted Debt Rate** | | 5.04% |
| **Regulated Rate of Return** | | 6.45% |

**2013**

| Description | Deemed Portion | Effective Rate |
|---|---|---|
| Long-Term Debt | 56.00% | 5.17% |
| Short-Tern Debt | 4.00% | 2.07% |
| Return On Equity | 40.00% | 8.98% |
| **Weighted Debt Rate** | | 4.97% |
| **Regulated Rate of Return** | | 6.57% |

## WORKING CAPITAL ALLOWANCE FOR 2012

| Distribution Expenses | | |
|---|---|---|
| Distribution Expenses - Operation | | 1,111,298 |
| Distribution Expenses - Maintenance | | 1,802,869 |
| Billing and Collecting | | 2,208,332 |
| Community Relations | | 169,137 |
| Administrative and General Expenses | | 2,521,038 |
| Taxes Other than Income Taxes | | 5,091 |
| **Total Eligible Distribution Expenses** | | **7,817,765** |
| Power Supply Expenses | | 89,860,293 |
| **Total Working Capital Expenses** | | 97,678,058 |
| | | |
| Working Capital Allowance @ | 15.00% | 14,651,709 |

## WORKING CAPITAL ALLOWANCE FOR 2013

| Distribution Expenses | | |
|---|---|---|
| Distribution Expenses - Operation | | 1,576,506 |
| Distribution Expenses - Maintenance | | 2,033,090 |
| Billing and Collecting | | 2,863,215 |
| Community Relations | | 232,777 |
| Administrative and General Expenses | | 2,498,437 |
| Taxes Other than Income Taxes | | 12,000 |
| **Total Eligible Distribution Expenses** | | **9,216,025** |
| Power Supply Expenses | | 98,022,828 |
| **Total Working Capital Expenses** | | 107,238,853 |
| | | |
| Working Capital Allowance @ | **13.00%** | 13,941,051 |

## RATE BASE CALCULATION FOR 2012

| | |
|---|---|
| Fixed Assets Opening Balance 2012 | 62,426,332 |
| Fixed Assets Closing Balance 2012 | 60,300,589 |
| **Average Fixed Asset Balance for 2011** | 61,363,461 |
| Working Capital Allowance | 14,651,709 |
| **Rate Base** | 76,015,169 |
| Regulated Rate of Return | 6.45% |
| **Regulated Return on Capital** | 4,906,697 |
| Deemed Interest Expense | 2,300,897 |
| Deemed Return on Equity | 2,605,800 |

## RATE BASE CALCULATION FOR 2013

| | |
|---|---|
| Fixed Assets Opening Balance 2013 | **64,666,003** |
| Fixed Assets Closing Balance 2013 | 64,948,633 |
| **Average Fixed Asset Balance for 2013** | 64,807,318 |
| Working Capital Allowance | 13,941,051 |
| **Rate Base** | 78,748,369 |
| Regulated Rate of Return | 6.57% |
| **Regulated Return on Capital** | 5,175,141 |
| Deemed Interest Expense | 2,346,500 |
| Deemed Return on Equity | 2,828,641 |

# APPENDIX A

# COPY OF PROMISSORY NOTE WITH CITY OF BRANTFORD

**PROMISSORY NOTE**

**Due: February 1, 2016**

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 specifed herein on February 1, 2016 (the "Maturity Date"). Interest on the Principal Sum shall accrue from the first day of February, 2011 and be payable at a rate per annum equal to the rate of five and eighty-seven one hundredths percent (5.87%). Interest at the aforesaid rate 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 ninety (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.

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

DATED this 27th day of January 2011.

**BRANTFORD POWER INC.**

Per: Heather Wyatt
Name: Heather Wyatt
Title: Secretary

Per: Tim Curtis
Name: Tim Curtis
Title: Chair

# REVENUE DEFICIENCY - OVERVIEW

BPI's net revenue deficiency is $1,069,602 and when grossed up for PILs BPI's revenue deficiency is $1,409,559. This deficiency is calculated as the difference between the 2013 Test Year Revenue Requirement of $17,864,601 and the Forecast 2013 Test Year Revenue Requirement at BPI's 2012 approved distribution rates of $16,455,042. Table 6.2 on the following page provides the revenue deficiency calculations for the 2013 Test Year at Existing 2012 Board Approved rates and the 2013 Test Year Revenue Requirement.

**Revenue Requirement:**

BPI's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILS
- Deemed Interest & Return on Equity

BPI's revenue requirement is primarily received through electricity distribution rates and offset by revenue from Board Approved specific service charges, late payment charges, interest, and other operating income.

BPI's 2008 BPI Board Approved Revenue Requirement was $16,879,874, as set out in Table 6.1 below:

**Table 6.1: 2008 Board Approved Revenue Requirement**

| Description | 2008 Board Approved | |
|---|---|---|
| Controllable OM&A Expenses | $ | 7,506,774 |
| Taxes other than income taxes | $ | 12,298 |
| Amortization Expense- PP&E | $ | 3,021,342 |
| PILS (with Gross Up) | $ | 1,360,025 |
| Regulated Return on Capital | $ | 4,979,435 |
| **Service Revenue Requirement** | $ | 16,879,874 |
| **Less: Revenue Offsets** | $ | (1,422,329) |
| **Base Revenue Requirement** | $ | 15,457,545 |

## Table 6.2 – Revenue Deficiency

**Revenue Deficiency Determination**

| Description | 2012 Bridge Actual | 2013 Test Existing Rates | 2013 Test - Required Revenue |
|---|---|---|---|
| **Revenue** | | | |
| Revenue Deficiency | | | **1,409,559** |
| Distribution Revenue | 14,309,974 | 15,293,896 | 15,293,896 |
| Other Operating Revenue (Net) | 632,386 | 1,161,146 | 1,161,146 |
| **Total Revenue** | **14,942,360** | **16,455,042** | **17,864,601** |
| **Costs and Expenses** | | | |
| Administrative & General, Billing & Collecting | 4,898,507 | 5,594,429 | 5,594,429 |
| Operation & Maintenance | 2,914,167 | 3,609,596 | 3,609,596 |
| Depreciation & Amortization | 3,837,203 | 2,995,584 | 2,995,584 |
| Property Taxes | 5,091 | 12,000 | 12,000 |
| Deemed Interest | 2,300,897 | 2,346,500 | 2,346,500 |
| **Total Costs and Expenses** | **13,955,865** | **14,558,108** | **14,558,108** |
| | | | |
| **Utility Income Before Income Taxes** | **986,495** | **1,896,934** | **3,306,492** |
| | | | |
| **Income Taxes:** | | | |
| Corporate Income Taxes | 301,701 | 137,894 | 477,851 |
| **Total Income Taxes** | **301,701** | **137,894** | **477,851** |
| | | | |
| **Utility Net Income** | **684,794** | **1,759,040** | **2,828,641** |
| | | | |
| | | | |
| **Income Tax Expense Calculation:** | | | |
| Accounting Income | 986,495 | 1,896,934 | 3,306,492 |
| Tax Adjustments to Accounting Income | 274,678 | (1,325,186) | (1,325,186) |
| **Taxable Income** | **1,261,173** | **571,747** | **1,981,306** |
| **Income Tax Expense** | 301,701 | 137,894 | 477,851 |
| **Tax Rate Refecting Tax Credits** | 23.92% | 24.12% | 24.12% |
| | | | |
| **Actual Return on Rate Base:** | | | |
| Rate Base | 76,015,169 | 78,748,369 | 78,748,369 |
| | | | |
| Interest Expense | 2,300,897 | 2,346,500 | 2,346,500 |
| Net Income | 684,794 | 1,759,040 | 2,828,641 |
| **Total Actual Return on Rate Base** | **2,985,691** | **4,105,539** | **5,175,141** |
| | | | |
| **Actual Return on Rate Base** | 3.93% | 5.21% | 6.57% |
| | | | |
| **Required Return on Rate Base:** | | | |
| Rate Base | 76,015,169 | 78,748,369 | 78,748,369 |
| | | | |
| **Return Rates:** | | | |
| Return on Debt (Weighted) | 5.04% | 4.97% | 4.97% |
| Return on Equity | 8.57% | 8.98% | 8.98% |
| | | | |
| Deemed Interest Expense | 2,300,897 | 2,346,500 | 2,346,500 |
| Return On Equity | 2,605,800 | 2,828,641 | 2,828,641 |
| **Total Return** | **4,906,697** | **5,175,141** | **5,175,141** |
| | | | |
| **Expected Return on Rate Base** | 6.45% | 6.57% | 6.57% |
| | | | |
| **Revenue Deficiency After Tax** | **1,921,006** | **1,069,602** | **0** |
| **Revenue Deficiency Before Tax** | **2,525,056** | **1,409,559** | **0** |

| **Tax Exhibit** | | | **2013** |
|---|---|---|---|
| Deemed Utility Income | | | 2,828,641 |
| Tax Adjustments to Accounting Income | | | (1,325,186) |
| **Taxable Income prior to adjusting revenue to PILs** | | | **1,503,455** |
| Tax Rate | | | 24.12% |
| Total PILs before gross up | | | **362,603** |
| **Grossed up PILs** | | | **477,851** |

# COST DRIVERS FOR REVENUE DEFICIENCY

BPI notes there are several factors that contribute to the gross revenue deficiency of $1,409,559 for the 2013 Test Year. The following discussion highlights some significant items that contribute to this deficiency.

The revenue deficiency is primarily the result of two factors:

1. The increases to OM&A costs due to the change in BPI's capitalization policy in the amount of $972,502; and

2. Increases as a result of BPI's organizational restructuring in 2012 and the splitting of the customer invoice in 2013 in the net amount of $437,405 and offset by other cost reductions.

The changes to BPI's capitalization policy are discussed in Exhibit 2, Tab 3, Schedule 4 and the cost impacts are discussed in Exhibit 4, Tab 2, Schedule 3 in relation to the cost Driver Table and description.

The changes to BPI's organizational structure and the cost impacts are discussed in Exhibit 4, Tab 2, Schedule 3.

# COST ALLOCATION OVERVIEW

## Introduction

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. BPI prepared a cost allocation information filing consistent with BPI's understanding of the Directions, the Guidelines, the Model and the Instructions. BPI submitted this filing to the Board on January 22, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this information would be a useful tool in future rate applications, indicating which classes are over-contributing and which are under-contributing revenue.

In BPI's 2008 EDR COS Application (EB-2007-0698), the results of the original cost allocation study filed on January 22, 2007 were used as a basis for BPI to propose reallocations of distribution costs across customer classes to address the issue of cross-subsidization. The reallocations were based on the objective of moving the revenue to cost ratios to be within the Board's acceptable range as outlined in the "Report on Application of Cost Allocation for Electricity Distributors" (the Cost Allocation Report) issued by the Board on November 28, 2007.

In 2009, BPI prepared an additional cost allocation study, for use in a motion by Brant County Power Inc. (EB-2009-0063) ("the Brant County Motion"). BPI included its embedded distributor in this cost allocation study, in order to determine the level of cost which is associated with providing service to this customer class. The results of this cost allocation were used to determine the rate for the Embedded Distributor Class.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released the new Cost Allocation model and instructed 2012 Cost of Service filers to use the revised model in their applications. In the March 31st Board Report, the Board stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

For the purposes of this Application, BPI has submitted the revised cost allocation study to reflect 2013 Test Year costs, customer numbers and demand values. The 2013 demand values are based on the weather normalized load forecast used to design rates.

WEIGHTING FACTORS

BPI has developed weighting factors as outlined below based on discussions with BPI staff experienced in the subject areas.

**Services (Account 1855)**

The services weighting factors were derived by comparing the cost of a typical service drop in each customer class. BPI does not record the cost of service drops for USL, Street Lighting, Sentinel Lighting or Embedded Distributor in account 1855. This practice has resulted in a services weighting factor of 0 for those classes. Further, the BPI does not record the cost of service drops on underground General Service assets in 1855. This has been reflected in the services weighting factor calculation for those classes.

For each class, BPI has calculated a separate typical service drop cost for overhead and underground assets. The next step consisted of computing the expected proportion of underground and overhead service drops in each customer class. A weighted average cost for each class was evaluated using these factors. The weighted average cost for Residential was set as a weighting factor of 1. The General Service weighting factors were determined by dividing their respective weighted average service drop cost per customer by the Residential weighted average cost on a per customer basis.

The resultant weighting factors are set out in Table 7.1 below.

| **Table 7.1: Services Weighting Factors** | |
|---|---|
| **Rate Class** | **Services Weighting Factor** |
| Residential | 1 |
| General Service < 50kW | 0.6 |
| General Service ≥ 50 kW | 0.7 |
| All other classes | N/A |

**Billing and Collection (Accounts 5315 – 5340, except 5335)**

BPI has calculated Billing and Collection weighting factors based on consultations with experienced BPI customer services colleagues. The driving factor determining the costs associated with billing and collecting is the level of effort and time necessary for customer service staff to perform these activities. It was the opinion of staff processing these accounts that for interval metered customers (all GS>50 and many GS<50 customers), there is a greater level of double-checking data during the billing process for accuracy. Additionally, there is a greater level of effort per bill in the standby class. In this class, billing quantities need to be double-checked and calculated manually several times a year.

For rate classes in which a number of accounts may be consolidated on one bill, the weighting factor has been left at 1. This reflects the observation that minimal additional effort is required to consolidate the billing.

The weighting factors that have been applied to Billing and Collecting costs are set out in Table 7.2 below

| **Table 7.2: Billing and Collecting Weighting Factors** | |
|---|---|
| **Rate Class** | **Billing Weighting Factor** |
| Residential | 1 |
| General Service < 50kW | 2 |
| General Service ≥ 50 kW | 8 |
| Street Light (per connection) other | 1 |
| Sentinel Light | 1 |
| Unmetered Scattered Load | 1 |
| Embedded Distributor | 1 |

**Meter Capital (Sheet I7.1)**

The meter capital costs per meter were calculated based on the actual installed cost of the meters in BPI's service area.

The meter capital costs per meter are presented below in Table 7.3.

| **Table 7.3: Cost per Meter Type** | |
|---|---|
| **Meter Types** | **Cost per Meter** |
| Single Phase 200 Amp – Urban | $121.00 |
| Central Meter | $250.00 |
| Three-phase - No demand | $631.00 |
| Smart Meters | $109.00 |
| Demand without IT (usually three-phase) | $709.00 |
| Demand with IT | $1,891.00 |
| Demand with IT and Interval Capability – Secondary | $2,491.00 |
| Demand with IT and Interval Capability – Primary | $27,206.00 |
| Smart Meters - Network Meter | $211.00 |
| Smart Meters -Three Phase No Demand | $700.00 |

**Meter Reading (Sheet I7.2)**

In 2013, BPI has three methods of meter reading used for its customers. The large majority are Smart Meter reads, which are automated and very straight-forward. There are also some conventional meters left in the General Services classes which require in-field reads. These meter reads are low-cost but require relatively more effort and greater per-unit cost than smart meter reads. Lastly, interval reading costs have been assigned a weight factor of 8, based on a calculation comparing the length of time, and number and cost of staff necessary for reading the interval meters and smart meters each month.

The Meter Reading Weighting Factors are set out below in Table 7.4

| **Table 7.4: Meter Reading Weighting Factors** | |
|---|---|
| **Meter Type** | **Meter Reading Weighting Factor** |
| Smart Meter | 1 |
| GS - Vehicle with other services | 2 |
| Interval | 8 |

## SUMMARY OF RESULTS AND PROPOSED CHANGES

The data used in the updated cost allocation study is consistent with BPI's cost data that supports the proposed 2013 revenue requirement outlined in this Application. Consistent with the Guidelines, BPI's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing. BPI does not have any bulk assets. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to BPI, its engineering records, and its customer and financial information systems. The cost allocation study has been included in Appendix A. Additionally, updated analyses and calculations have been completed for the distance of road with service lines; pole access revenue breakdown (into primary and secondary), number of bills per class, number of devices per class, and bad debt and late payment history per class.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2013 continuity schedule shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2013 customer forecast outlined in Exhibit 3. The load profiles for all other rate classes are the same as those used in the original information filing but have been scaled to match the load forecast. The following Table 7.5 outlines the scaling factors used by rate class.

**Table 7.5: Load Profile Scaling Percentages**

| Rate Class | 2004 Weather Normal Values used in Informational Filing (kWh) | 2013 Weather Normal Values (kWh) | Scaling Factor |
|---|---|---|---|
| **Residential** | 284,000,199 | 280,913,502 | 100% |
| **GS>50kW** | 559,706,033 | 531,977,718 | 95% |
| **Street Lighting** | 6,528,516 | 7,553,004 | 116% |
| **Sentinel Lighting** | 398,304 | 443,490 | 111% |
| **GS<50 kW** | 102,044,553 | 97,535,297 | 96% |
| **Standby** | 778,877 | 0 | 0% |
| **USL** | 2,833,799 | 1,454,727 | 51% |
| **Large User** | 46,917,839 | 0 | 0% |
| **Embedded Distributor** | 77,273,703 | 73,940,068 | 96% |

The scaling factor for USL is 51%, as a result of reduced consumption in the 2013 forecast as compared to 2004. The USL class is comprised primarily of City of Brantford traffic light accounts. Between 2004 and 2008, the City of Brantford undertook an LED retrofit for all its traffic lights, reducing consumption of traffic lights by 80% over the four years (the most significant reductions were made in 2007 and 2008). The difference in USL kWh between 2004 and 2013 can be attributed to this reduction.

The allocated cost by rate class from the cost allocation used in the Brant County Motion filing and 2013 updated study are provided in the following Table 7.6. The results shown under the 2007 information filing column exclude the "cost" and "revenues" of the transformation allowance as outlined in the June 28, 2010 filing requirements.

**Table 7.6: Allocated Cost**

| Classes | Costs Allocated from BCP Motion Study | % | Costs Allocated in Test Year Study | % |
|---|---|---|---|---|
| Residential | $ 9,924,666 | 58.8% | $ 10,821,187 | 60.6% |
| GS < 50 kW | $ 1,955,571 | 11.6% | $ 2,088,907 | 11.7% |
| GS > 50 kW | $ 3,295,266 | 19.5% | $ 4,357,784 | 24.4% |
| Large User | $ 240,015 | 1.4% | | 0.0% |
| Street Lighting | $ 906,296 | 5.4% | $ 137,888 | 0.8% |
| Sentinel Lighting | $ 72,502 | 0.4% | $ 84,146 | 0.5% |
| USL | $ 77,698 | 0.5% | $ 79,639 | 0.4% |
| Standby | $ 104,404 | 0.6% | | 0.0% |
| Embedded Distributor | $ 303,456 | 1.8% | $ 295,051 | 1.7% |
| **Total** | $ 16,879,874 | 100.0% | $ 17,864,601 | 100.0% |

In its Cost Allocation Study filed as part of the BCP motion, BPI had modeled a Large User rate. BPI did not implement a Large User class following that study, and is not applying to implement one at this time.

There is a change in the level of cost allocated to the street lighting class between the 2008 and 2013 Cost Allocation studies. This can be attributed to an enhancement in the methodology used in 2013. The 2009 study allocated costs based on 10,056 street light connections. In 2013, BPI has changed its methodology. While there are forecast to be 10,355 streetlight devices in BPI's service territory, BPI has allocated street lighting costs based on 645 street light connections. BPI submits that, in accordance with Section 2.10.1 of the Board's Filing Requirements, the number of connections (rather than fixtures/devices) is the appropriate value to use to allocate customer related costs to this class. BPI arrived at the estimated number of connections by surveying a random sample of connections in its service territory, and calculating the average number of devices on each of these connections. The average was found to be 16.05 devices per connection. This average was applied to the number of devices, available from BPI's billing system, to arrive at the estimate of 645 connections.

As shown in the table above the Embedded Distributor class is included as part of the cost allocation. Brant County Power Inc. (BCPI) is an embedded distributor of BPI. Currently BPI charges BCPI the monthly service charge of the GS > 50 kW class for the 3 embedded feeder points. The remaining cost allocated to the Embedded Distributor class (as per the Brant County Motion Cost Allocation Study) is recovered through a distribution volumetric charge. No BPI transformer or secondary assets are used to provide the embedded distributor service. As a result, no costs related to these assets have been assigned to BCPI in the 2013 Cost Allocation Study.

At this time, BPI's Standby Rate has been deemed interim per the Board's March 21, 2006 Decision in EB-2005-0529, which addressed the development of a standardized methodology for setting Standby rates. BPI does not propose to change its interim Standby rate, or to have it deemed final. As such, this rate class has not been included in the 2013 Cost Allocation Study. BPI has participated in, and continues to monitor the Board's "Development of a Standby Rate for Load Displacement Generation" (EB-2013-0004) consultation. BPI expects to treat its standby customer in accordance with any Board Decision or Direction resulting from the consultation process. The expected revenue from Standby rates has been included as distribution revenue offset in USoA account 4080-2.

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the Report of the Board on Cost Allocation released in relation to EB-2010-0219, dated March 31, 2011, the Board established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7.7 below. In addition Table 7.7 provides BPI's revenue to cost ratios from the BCP Motion Cost Allocation Study.

The following Table 7.7 sets out the revenue to cost ratios.

| Table 7.7: Revenue to Cost Ratios | | | | | |
|---|---|---|---|---|---|
| | 2006 Informational Filing | 2013 Cost Allocation Study | Proposed 2013 Ratio | Board Target Low | Board Target High |
| Residential | 94.5% | 95.8% | 95.8% | 85% | 115% |
| GS <50 | 83.1% | 81.9% | 82.0% | 80% | 120% |
| GS>50-Regular | 146.1% | 118.5% | 118.5% | 80% | 120% |
| Large Use >5MW | 142.6% | | | | |
| Street Light | 14.8% | 119.8% | 119.8% | 70% | 120% |
| Sentinel | 33.7% | 50.6% | 80.0% | 80% | 120% |
| Unmetered Scattered Load | 114.0% | 109.5% | 109.5% | 80% | 120% |
| Embedded Distributor | 140.3% | 109.0% | 100.0% | 85% | 115% |
| Back-up/Standby Power | 40.0% | | | | |

BPI is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring. For 2013, BPI proposes a realignment that will move the Sentinel class to 80%, the lower boundary of the Board's target range for that class. The additional revenue from this class will be offset by moving the Embedded Distributor class to a ratio of 100%. This is consistent with the Board Decision in the Brant County Motion, and will ensure that BPI's embedded distributor will pay only for the full cost of the distribution service provided. To ensure full revenue recovery, a small amount of revenue is left to be collected from one of the classes. The GS<50 class has been chosen as it is the class furthest below unity. The remaining revenue to be recovered from the GS<50 class ($1,735) has a minimal effect on the revenue-to-cost ratio for this class.

The following table 7.8 provides information on calculated class revenue. The resulting 2013 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

**Table 7.8: Calculated Class Revenue**

| Class | 2013 Base Revenue Allocated based on Proportion of Revenue at Existing Rates | 2013 Proposed Revenue | 2013 Proposed Base Revenue | 2013 Miscellaneous Revenue |
|---|---|---|---|---|
| Residential | $ 9,545,328 | $ 10,371,571 | $ 9,545,328 | $ 826,242 |
| GS < 50 kW | $ 1,591,043 | $ 1,712,337 | $ 1,592,778 | $ 119,559 |
| GS > 50 kW, if applicable | $ 4,983,913 | $ 5,165,984 | $ 4,983,913 | $ 182,071 |
| Street Lighting | $ 157,703 | $ 165,174 | $ 157,703 | $ 7,470 |
| Sentinel Lighting | $ 35,786 | $ 67,317 | $ 60,496 | $ 6,821 |
| Unmetered Scattered Load (USL) | $ 80,547 | $ 87,168 | $ 80,547 | $ 6,622 |
| Embedded distributor class | $ 309,134 | $ 295,051 | $ 282,689 | $ 12,362 |
| TOTAL | $ 16,703,454 | $ 17,864,601 | $ 16,703,454 | $ 1,161,146 |

# APPENDIX A

# 2013 UPDATED COST ALLOCATION STUDY

# 2013 Cost Allocation Model

## Sheet I6.1 Revenue Worksheet - Initial Application

| | |
|---|---|
| Total kWhs from Load Forecast | 919,877,738 |
| Total kWs from Load Forecast | 1,534,887 |
| Deficiency from RRWF | - 1,409,559 |
| Miscellaneous Revenue | 1,161,146 |

| | | | 1 | 2 | 3 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|
| Click here | ID | Total | Residential | GS <50 | GS>50-Regular | Street Light | Sentinel | Unmetered Scattered Load | Embedded Distributor |
| **Billing Data** | | | | | | | | | |
| Forecast kWh | CEN | 919,877,738 | 280,913,502 | 97,535,297 | 531,977,718 | 7,553,004 | 443,490 | 1,454,727 | |
| Forecast kW | CDEM | 1,534,887 | | | 1,354,270 | 23,455 | 1,356 | | 155,806 |
| Forecast kW, included in CDEM, of customers receiving line transformer allowance | | 738,729 | | 210.4 | 738,519 | | | | |
| Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank. | | - | | | | | | | |
| KWh excluding KWh from Wholesale Market Participants | CEN EWMP | 919,864,592 | 280,913,502 | 97,535,297 | 531,964,572 | 7,553,004 | 443,490 | 1,454,727 | - |
| kWh - 30 year weather normalized amount | | 919,877,738 | 280,913,502 | 97,535,297 | 531,977,718 | 7,553,004 | 443,490 | 1,454,727 | - |
| Existing Monthly Charge | | | $11.46 | $24.81 | $293.71 | $0.65 | $2.32 | $12.06 | $293.71 |
| Existing Distribution kWh Rate | | | $0.0138 | $0.0065 | | | | $0.0072 | |
| Existing Distribution kW Rate | | | | | $2.6043 | $2.7127 | $11.1228 | | $1.7488 |
| Existing TFOA Rate | | | | $0.60 | $0.60 | | | | |
| Additional Charges | | | | | | | | | |
| Distribution Revenue from Rates | | $15,737,133 | $8,739,824 | $1,456,906 | $5,006,446 | $144,395 | $32,766 | $73,750 | $283,047 |
| Transformer Ownership Allowance | | $443,238 | $0 | $126 | $443,111 | $0 | $0 | $0 | $0 |
| Net Class Revenue | CREV | $15,293,896 | $8,739,824 | $1,456,779 | $4,563,334 | $144,395 | $32,766 | $73,750 | $283,047 |
| **Data Mismatch Analysis** | | | | | | | | | |
| **Revenue with 30 year weather normalized kWh** | | 15,010,849 | 8,739,824 | 1,456,779 | 4,563,334 | 144,395 | 32,766 | 73,750 | - |

| Weather Normalized Data from Hydro One | Total | Residential | GS <50 | GS>50-Regular | Street Light | Sentinel | Unmetered Scattered Load | Embedded Distributor |
|---|---|---|---|---|---|---|---|---|
| **kWh - 30 year weather normalized amount** | 919,877,738 | 280,913,502 | 97,535,297 | 531,977,718 | 7,553,004 | 443,490 | 1,454,727 | - |
| **Loss Factor** | | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |

# 2013 Cost Allocation Model

## Sheet I6.2 Customer Data Worksheet - Initial Application

| | ID | Total | 1<br>Residential | 2<br>GS <50 | 3<br>GS>50-Regular | 7<br>Street Light | 8<br>Sentinel | 9<br>Unmetered Scattered Load | 10<br>Embedded Distributor |
|---|---|---|---|---|---|---|---|---|---|
| **Billing Data** | | | | | | | | | |
| Bad Debt 3 Year Historical Average | BDHA | $202,766 | $155,822 | $15,348 | $31,251 | $0 | $345 | $0 | $0 |
| Late Payment 3 Year Historical Average | LPHA | $136,110 | $110,129 | $11,033 | $14,823 | $0 | $16 | $109 | |
| Number of Bills | CNB | 461,545 | 415,449 | 32,465.00 | 5,038 | 12 | 3,240 | 5,329 | 12 |
| Number of Devices | | | | | | 10,355 | 635 | 437 | |
| Number of Connections (Unmetered) | CCON | 1,718 | | | | 645 | 635 | 437 | |
| Total Number of Customers | CCA | 38,842 | 35,364 | 2,764 | 420 | 1 | 270 | 20 | 3 |
| Bulk Customer Base | CCB | 38,842 | 35,364 | 2,764 | 420 | 1 | 270 | 20 | 3 |
| Primary Customer Base | CCP | 38,842 | 35,364 | 2,764 | 420 | 1 | 270 | 20 | 3 |
| Line Transformer Customer Base | CCLT | 38,771 | 35,364 | 2,757 | 359 | 1 | 270 | 20 | |
| Secondary Customer Base | CCS | 38,819 | 35,364 | 2,764 | 400 | 1 | 270 | 20 | |
| Weighted - Services | CWCS | 37,373 | 35,364 | 1,741 | 268 | - | - | - | - |
| Weighted Meter -Capital | CWMC | 6,714,938 | 3,995,867 | 1,410,508 | 1,308,563 | - | - | - | - |
| Weighted Meter Reading | CWMR | 40,150 | 35,364 | 2,855 | 1,932 | - | - | - | - |
| Weighted Bills | CWNB | 529,276 | 415,449 | 64,930 | 40,304 | 12 | 3,240 | 5,329 | 12 |

## Bad Debt Data

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Historic Year:** | 2009 | 209,072 | 155,080 | 19,068 | 33,889 | | 1,035 | | |
| **Historic Year:** | 2010 | 157,457 | 141,698 | 9,768 | 5,991 | | | | |
| **Historic Year:** | 2011 | 241,770 | 170,686 | 17,210 | 53,874 | | | | |
| **Three-year average** | | **202,766** | **155,822** | **15,348** | **31,251** | **-** | **345** | **-** | **-** |

# 2013 Cost Allocation Model

## Sheet O1 Revenue to Cost Summary Worksheet - Initial Application

**Instructions:**
Please see the first tab in this workbook for detailed instructions

### Class Revenue, Cost Analysis, and Return on Rate Base

| | | | 1 | 2 | 3 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|
| Rate Base Assets | | Total | Residential | GS <50 | GS>50-Regular | Street Light | Sentinel | Unmetered Scattered Load | Embedded Distributor |
| crev | Distribution Revenue at Existing Rates | $15,293,896 | $8,739,824 | $1,456,779 | $4,563,334 | $144,395 | $32,766 | $73,750 | $283,047 |
| mi | Miscellaneous Revenue (mi) | $1,161,146 | $826,242 | $119,559 | $182,071 | $7,470 | $6,821 | $6,622 | $12,362 |
| | | Miscellaneous Revenue Input equals Output | | | | | | | |
| | **Total Revenue at Existing Rates** | $16,455,042 | $9,566,067 | $1,576,338 | $4,745,405 | $151,865 | $39,587 | $80,371 | $295,408 |
| | Factor required to recover deficiency (1 + D) | 1.0922 | | | | | | | |
| | Distribution Revenue at Status Quo Rates | $16,703,454 | $9,545,328 | $1,591,043 | $4,983,913 | $157,703 | $35,786 | $80,547 | $309,134 |
| | Miscellaneous Revenue (mi) | $1,161,146 | $826,242 | $119,559 | $182,071 | $7,470 | $6,821 | $6,622 | $12,362 |
| | **Total Revenue at Status Quo Rates** | $17,864,601 | $10,371,571 | $1,710,602 | $5,165,984 | $165,174 | $42,607 | $87,168 | $321,495 |
| | **Expenses** | | | | | | | | |
| di | Distribution Costs (di) | $3,011,210 | $1,729,851 | $289,220 | $856,586 | $32,608 | $15,205 | $11,300 | $76,440 |
| cu | Customer Related Costs (cu) | $3,461,601 | $2,623,047 | $449,415 | $350,780 | $137 | $14,786 | $23,383 | $53 |
| ad | General and Administration (ad) | $2,743,214 | $1,821,777 | $313,023 | $532,080 | $14,877 | $12,788 | $14,438 | $34,232 |
| dep | Depreciation and Amortization (dep) | $2,995,584 | $1,641,644 | $392,766 | $857,933 | $27,498 | $12,642 | $9,302 | $53,800 |
| INPUT | PILs (INPUT) | $477,851 | $254,003 | $54,479 | $148,808 | $5,306 | $2,428 | $1,793 | $11,033 |
| INT | Interest | $2,346,500 | $1,247,290 | $267,518 | $730,726 | $26,054 | $11,923 | $8,807 | $54,180 |
| | **Total Expenses** | $15,035,959 | $9,317,612 | $1,766,421 | $3,476,913 | $106,480 | $69,772 | $69,023 | $229,738 |
| | **Direct Allocation** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| NI | Allocated Net Income (NI) | $2,828,641 | $1,503,574 | $322,486 | $880,871 | $31,408 | $14,373 | $10,617 | $65,313 |
| | **Revenue Requirement (includes NI)** | $17,864,601 | $10,821,187 | $2,088,907 | $4,357,784 | $137,888 | $84,146 | $79,639 | $295,051 |
| | | Revenue Requirement Input equals Output | | | | | | | |
| | **Rate Base Calculation** | | | | | | | | |
| | **Net Assets** | | | | | | | | |
| dp | Distribution Plant - Gross | $98,884,168 | $52,758,270 | $11,236,479 | $30,664,116 | $1,125,669 | $517,733 | $380,884 | $2,201,016 |
| gp | General Plant - Gross | $5,314,103 | $2,829,383 | $605,946 | $1,650,942 | $59,232 | $27,145 | $20,029 | $121,426 |
| accum dep | Accumulated Depreciation | ($34,814,160) | ($18,632,256) | ($3,930,552) | ($10,770,578) | ($410,884) | ($190,054) | ($139,163) | ($740,672) |
| co | Capital Contribution | ($4,576,793) | ($2,504,945) | ($523,315) | ($1,364,356) | ($54,336) | ($25,457) | ($18,478) | ($85,906) |
| | **Total Net Plant** | $64,807,318 | $34,450,453 | $7,388,557 | $20,180,123 | $719,681 | $329,367 | $243,272 | $1,495,864 |
| | **Directly Allocated Net Fixed Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| COP | Cost of Power (COP) | $98,022,828 | $29,934,722 | $10,393,562 | $56,687,402 | $804,864 | $47,259 | $155,019 | $0 |
| | OM&A Expenses | $9,216,025 | $6,174,675 | $1,051,658 | $1,739,446 | $47,622 | $42,779 | $49,121 | $110,725 |
| | Directly Allocated Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | ***Subtotal*** | *$107,238,853* | *$36,109,396* | *$11,445,221* | *$58,426,848* | *$852,485* | *$90,038* | *$204,139* | *$110,725* |
| | **Working Capital** | $13,941,051 | $4,694,222 | $1,487,879 | $7,595,490 | $110,823 | $11,705 | $26,538 | $14,394 |
| | **Total Rate Base** | $78,748,369 | $39,144,674 | $8,876,436 | $27,775,614 | $830,505 | $341,072 | $269,811 | $1,510,258 |
| | | Rate Base Input equals Output | | | | | | | |
| | **Equity Component of Rate Base** | $31,499,348 | $15,657,870 | $3,550,574 | $11,110,245 | $332,202 | $136,429 | $107,924 | $604,103 |
| | **Net Income on Allocated Assets** | $2,802,554 | $1,053,958 | ($55,819) | $1,689,071 | $58,694 | ($27,166) | $18,145 | $65,670 |
| | **Net Income on Direct Allocation Assets** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **Net Income** | $2,802,554 | $1,053,958 | ($55,819) | $1,689,071 | $58,694 | ($27,166) | $18,145 | $65,670 |
| | **RATIOS ANALYSIS** | | | | | | | | |
| | **REVENUE TO EXPENSES STATUS QUO%** | 100.00% | 95.85% | 81.89% | 118.55% | 119.79% | 50.63% | 109.45% | 108.96% |
| | EXISTING REVENUE MINUS ALLOCATED COSTS | ($1,409,559) | ($1,255,120) | ($512,569) | $387,622 | $13,978 | ($44,559) | $732 | $358 |
| | | Deficiency Input equals Output | | | | | | | |
| | STATUS QUO REVENUE MINUS ALLOCATED COSTS | $0 | ($449,616) | ($378,305) | $808,201 | $27,286 | ($41,539) | $7,529 | $26,445 |
| | RETURN ON EQUITY COMPONENT OF RATE BASE | 8.90% | 6.73% | -1.57% | 15.20% | 17.67% | -19.91% | 16.81% | 10.87% |

# 2013 Cost Allocation Model

**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Initial Application**

Output sheet showing minimum and maximum level for Monthly Fixed Charge

## Summary

| | 1 | 2 | 3 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|
| | Residential | GS <50 | GS>50-Regular | Street Light | Sentinel | Unmetered Scattered Load | Embedded Distributor |
| Customer Unit Cost per month - Avoided Cost | $5.68 | $17.82 | $95.08 | -$0.02 | $1.18 | $2.82 | -$15.83 |
| Customer Unit Cost per month - Directly Related | $7.47 | $22.26 | $117.86 | -$0.01 | $1.71 | $4.04 | -$15.40 |
| Customer Unit Cost per month - Minimum System with PLCC Adjustment | $18.90 | $35.58 | $157.10 | $7.03 | $10.96 | $12.02 | -$11.32 |
| Existing Approved Fixed Charge | $11.46 | $24.81 | $293.71 | $0.65 | $2.32 | $12.06 | $293.71 |

## Information to be Used to Allocate PILs, ROD, ROE and A&G

| | | 1 | 2 | 3 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|
| | Total | Residential | GS <50 | GS>50-Regular | Street Light | Sentinel | Unmetered Scattered Load | Embedded Distributor |
| **General Plant - Gross Assets** | $5,314,103 | $2,829,383 | $605,946 | $1,650,942 | $59,232 | $27,145 | $20,029 | $121,426 |
| **General Plant - Accumulated Depreciation** | ($3,145,197) | ($1,674,595) | ($358,634) | ($977,124) | ($35,057) | ($16,066) | ($11,854) | ($71,867) |
| **General Plant - Net Fixed Assets** | $2,168,906 | $1,154,789 | $247,312 | $673,818 | $24,175 | $11,079 | $8,175 | $49,559 |
| **General Plant - Depreciation** | $189,285 | $100,781 | $21,583 | $58,806 | $2,110 | $967 | $713 | $4,325 |
| **Total Net Fixed Assets Excluding General Plant** | $62,638,412 | $33,295,664 | $7,141,246 | $19,506,305 | $695,506 | $318,288 | $235,098 | $1,446,305 |
| **Total Administration and General Expense** | $2,743,214 | $1,821,777 | $313,023 | $532,080 | $14,877 | $12,788 | $14,438 | $34,232 |
| **Total O&M** | $6,428,356 | $4,323,003 | $733,562 | $1,199,074 | $32,520 | $29,785 | $34,445 | $75,967 |

## Scenario 1

***Accounts included in Avoided Costs Plus General Administration Allocation***

| | | | 1 | 2 | 3 | 7 | 8 | 9 | 10 | |
|---|---|---|---|---|---|---|---|---|---|---|
| USoA Account # | Accounts | Total | Residential | GS <50 | GS>50-Regular | Street Light | Sentinel | Unmetered Scattered Load | Embedded Distributor | |
| | **Distribution Plant** | | | | | | | | | |
| 1860 | Meters | $9,582,247 | $5,702,120 | $2,012,802 | $1,867,325 | $0 | $0 | $0 | $0 | CWMC |
| | **Accumulated Amortization** | | | | | | | | | |
| | Accum. Amortization of Electric Utility Plant - Meters only | ($3,143,834) | ($1,870,806) | ($660,379) | ($612,650) | $0 | $0 | $0 | $0 | |
| | **Meter Net Fixed Assets** | **$6,438,413** | **$3,831,315** | **$1,352,423** | **$1,254,676** | **$0** | **$0** | **$0** | **$0** | |
| | **Misc Revenue** | | | | | | | | | |
| 4082 | Retail Services Revenues | ($38,639) | ($25,888) | ($4,409) | ($7,293) | ($200) | ($179) | ($206) | ($464) | CWNB |
| 4084 | Service Transaction Requests (STR) Revenues | ($11,660) | ($7,812) | ($1,331) | ($2,201) | ($60) | ($54) | ($62) | ($140) | CWNB |
| 4090 | Electric Services Incidental to Energy Sales | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | CWNB |
| 4220 | Other Electric Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | NFA |
| 4225 | Late Payment Charges | ($120,000) | ($97,095) | ($9,727) | ($13,068) | $0 | ($14) | ($96) | $0 | LPHA |
| | *Sub-total* | *($170,299)* | *($130,795)* | *($15,467)* | *($22,562)* | *($260)* | *($247)* | *($364)* | *($604)* | |
| | **Operation** | | | | | | | | | |
| 5065 | Meter Expense | $593,094 | $352,933 | $124,583 | $115,578 | $0 | $0 | $0 | $0 | CWMC |
| 5070 | Customer Premises - Operation Labour | $5,292 | $4,647 | $363 | $55 | $85 | $83 | $57 | $0 | CCA |
| 5075 | Customer Premises - Materials and Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | CCA |
| | *Sub-total* | *$598,386* | *$357,581* | *$124,946* | *$115,633* | *$85* | *$83* | *$57* | *$0* | |
| | **Maintenance** | | | | | | | | | |
| 5175 | Maintenance of Meters | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 1860 |
| | **Billing and Collection** | | | | | | | | | |
| 5310 | Meter Reading Expense | $240,556 | $211,877 | $17,106 | $11,573 | $0 | $0 | $0 | $0 | CWMR |
| 5315 | Customer Billing | $964,616 | $757,164 | $118,336 | $73,455 | $22 | $5,905 | $9,712 | $22 | CWNB |
| 5320 | Collecting | $536,496 | $421,116 | $65,816 | $40,854 | $12 | $3,284 | $5,402 | $12 | CWNB |
| 5325 | Collecting- Cash Over and Short | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | CWNB |
| 5330 | Collection Charges | $500 | $392 | $61 | $38 | $0 | $3 | $5 | $0 | CWNB |
| | Sub-total | $1,742,168 | $1,390,550 | $201,319 | $125,919 | $34 | $9,192 | $15,119 | $34 | |
| | Total Operation, Maintenance and Billing | $2,340,554 | $1,748,131 | $326,265 | $241,553 | $119 | $9,276 | $15,176 | $34 | |
| | **Amortization Expense - Meters** | $772,256 | $459,547 | $162,216 | $150,492 | $0 | $0 | $0 | $0 | |
| | **Allocated PILs** | $47,472 | $28,248 | $9,972 | $9,252 | $0 | $0 | $0 | $0 | |
| | **Allocated Debt Return** | $233,113 | $138,714 | $48,967 | $45,432 | $0 | $0 | $0 | $0 | |
| | **Allocated Equity Return** | $281,012 | $167,216 | $59,029 | $54,767 | $0 | $0 | $0 | $0 | |
| | **Total** | **$3,504,108** | **$2,411,061** | **$590,983** | **$478,934** | **($141)** | **$9,028** | **$14,812** | **($570)** | |

## RATE DESIGN OVERVIEW

This Exhibit documents the calculation of BPI's proposed distribution rates by rate class for the 2013 test year, based on the rate design as proposed in this Exhibit.

BPI has determined its total 2013 service revenue requirement to be $17,864,601. The total revenue offsets in the amount of $1,161,146 reduce BPI's total service revenue requirement to a base revenue requirement to $16,703,454 which is used to determine the proposed distribution rates. The base revenue requirement is derived from BPI's 2013 capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in the Table below.

**Table 8.1 : Calculation of Base Revenue Requirement**

| Description | Amount | |
|---|---|---|
| OM&A Expenses | $ | 9,216,025 |
| Amortization Expenses | $ | 2,995,584 |
| Regulated Return On Capital | $ | 5,175,141 |
| PILs | $ | 477,851 |
| **Service Revenue Requirement** | **$** | **17,864,601** |
| **Less: Revenue Offsets** | $ | 1,161,146 |
| **Base Revenue Requirement** | **$** | **16,703,454** |

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. The following Table shows how the base revenue requirement has been allocated to the rate classes.

**Table 8.2: Rate Class Base Revenue Requiremen**

| Class | 2013 Proposed Base Revenue |
|---|---|
| **Residential** | $ 9,545,328 |
| **GS < 50 kW** | $ 1,592,778 |
| **GS > 50 kW** | $ 4,983,913 |
| **Embedded Distributor** | $ 282,689 |
| **Sentinel Lighting** | $ 60,496 |
| **Street Lighting** | $ 157,703 |
| **Unmetered Scattered Load** | $ 80,547 |
| **TOTAL** | $ 16,703,454 |

## Determination of Monthly Fixed Charges

Based on applying the existing approved monthly service charges to the forecasted number of customers for 2013 and applying the existing approved distribution volumetric charge, including the adjustment for transformation allowance, to the 2013 forecasted volumes, the following Table outlines BPI's current split between fixed and variable distribution revenue.

**Table 8.3: Current Fixed Variable Split**

| | 2013 Fixed Revenue at 2012 Rates | 2013 Variable Revenue at 2012 Rates (TA removed) | Total 2013 revenue at 2012 rates (TA removed) | Fixed Revenue Proportion | Variable Revenue Proportion |
|---|---|---|---|---|---|
| **Residential** | $ 4,863,218 | $ 3,876,606 | $ 8,739,824 | 55.64% | 44.36% |
| **GS < 50 kW** | $ 822,926 | $ 633,853 | $ 1,456,779 | 56.49% | 43.51% |
| **GS 50 to 4999** | $ 1,479,521 | $ 3,083,813 | $ 4,563,334 | 32.42% | 67.58% |
| **Embedded Distributor** | $ 10,574 | $ 272,473 | $ 283,047 | 3.74% | 96.26% |
| **Sentinel Lights** | $ 17,682 | $ 15,084 | $ 32,766 | 53.96% | 46.04% |
| **Street Lighting** | $ 80,768 | $ 63,628 | $ 144,395 | 55.94% | 44.06% |
| **Unmetered and Scattered** | $ 63,276 | $ 10,474 | $ 73,750 | 85.80% | 14.20% |
| **TOTAL** | **$ 7,337,964** | **$ 7,955,931** | **$ 15,293,896** | **47.98%** | **52.02%** |

BPI submits that it is appropriate for 2013 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications.

In accordance with the filing requirements the following information has been provided with regards to the MSC.

| **Table 8.4: Monthly Service Charge Information from Cost Allocation Model** | | | |
|---|---|---|---|
| **Class** | Existing Approved Fixed Charge | Customer Unit Cost per month - Avoided Cost | Customer Unit Cost per month - Minimum System with PLCC Adjustment |
| **Residential** | $11.46 | $5.68 | $18.90 |
| **GS <50** | $24.81 | $17.82 | $35.58 |
| **GS>50** | $293.71 | $95.08 | $157.10 |
| **Embedded Distributor** | $293.71 | -$15.83 | -$11.32 |
| **Sentinel** | $2.32 | $1.18 | $10.96 |
| **Street Light** | $0.65 | -$0.02 | $7.03 |
| **Unmetered Scattered Load** | $12.06 | $2.82 | $12.02 |

Consistent with the Board's Decision on the 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities; the Board's Decision's on Atikokan Hydro's 2012 cost of service rate application and the recent Board Decision on Centre Wellington Hydro's 2013 cost of service application, this Application proposes to maintain the current fixed/variable proportions for all rate classes as shown in the following Table 8.5.

| **Table 8.5: Proposed Monthly Service Charge** | | | | | |
|---|---|---|---|---|---|
| **Customer Class** | **Total Net Rev. Requirement** | **Fixed Proportion** | **Total Fixed Revenue** | **Annualized Customers** | **Proposed Fixed Rate** |
| **Residential** | $ 9,545,328 | 55.64% | $ 5,311,435 | 424,365 | $ 12.52 |
| **GS < 50 kW** | $ 1,592,778 | 56.49% | $ 899,751 | 33,169 | $ 27.13 |
| **GS 50 to 4999** | $ 4,983,913 | 32.42% | $ 1,615,881 | 5,037 | $ 320.78 |
| **Embedded Distributor** | $ 282,689 | 3.74% | $ 10,560 | 36 | $ 293.34 |
| **Sentinel Lights** | $ 60,496 | 53.96% | $ 32,646 | 7,621 | $ 4.28 |
| **Street Lighting** | $ 157,703 | 55.94% | $ 88,212 | 124,258 | $ 0.71 |
| **Unmetered and Scattered** | $ 80,547 | 85.80% | $ 69,107 | 5,247 | $ 13.17 |
| **TOTAL** | **$ 16,703,454.42** | | **$8,027,593** | | |

## Proposed Volumetric Charges

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2013 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides BPI calculations of its proposed variable distribution charges for the 2013 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

**Table 8.6: Proposed Distribution Volumetric Charges**

| Customer Class | Total Net Rev. Requirement | Total Fixed Revenue | Total Variable Revenue | Annualized kWh | Measure- kWh or kW | Proposed Distribution Variable Rate before TA |
|---|---|---|---|---|---|---|
| **Residential** | $ 9,545,328 | $ 5,311,435 | $ 4,233,893 | 280,913,502 | kWh | $ 0.0151 |
| **GS < 50 kW** | $ 1,592,778 | $ 899,751 | $ 693,027 | 97,535,297 | kWh | $ 0.0071 |
| **GS 50 to 4999** | $ 4,983,913 | $ 1,615,881 | $ 3,368,032 | 1,354,270 | kW | $ 2.4870 |
| **Embedded Distributor** | $ 282,689 | $ 10,560 | $ 272,129 | 155,806 | kW | $ 1.7466 |
| **Sentinel Lights** | $ 60,496 | $ 32,646 | $ 27,850 | 1,356 | kW | $ 20.5359 |
| **Street Lighting** | $ 157,703 | $ 88,212 | $ 69,492 | 23,455 | kW | $ 2.9627 |
| **Unmetered and Scattered** | $ 80,547 | $ 69,107 | $ 11,439 | 1,454,727 | kWh | $ 0.0079 |
| **TOTAL** | **$16,703,454.42** | **$ 8,027,593** | **$8,675,862** | | | |

## Transformer Allowance

Currently, BPI provides a Transformer Allowance to those customers that own their transformation facilities. BPI proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of the Transformer Allowance expected to be provided to those GS > 50 kW and GS< 50 kW customers that own their transformers is included in the volumetric charge. As a result, the proposed volumetric charge of $2.4870 per kW for the GS > 50 kW customer class is increased by $0.3272 per kW to include the amount of the Transformer Allowance in the GS > 50 kW class distribution volumetric rate. This means the total proposed distribution volumetric charge for the GS > 50 kW class will be $2.8142. However, for the GS < 50 kW class, the distribution volumetric charge of $0.0071 does not change since the amount of the Transformer Allowance is very small for this class.

**Proposed Distribution Rates**

The following Table sets out BPI's proposed 2013 electricity distribution rates based on the foregoing calculations.

| Table 8.7 Proposed Distribution Rates | | | |
|---|---|---|---|
| **Customer Class** | **Proposed Fixed Rate** | **Measure-kWh or kW** | **Proposed Distribution Variable Rate after TA** |
| **Residential** | $ 12.52 | kWh | $ 0.0151 |
| **GS < 50 kW** | $ 27.13 | kWh | $ 0.0071 |
| **GS 50 to 4999** | $ 320.78 | kW | $ 2.8142 |
| **Embedded Distributor** | $ 293.34 | kW | $ 1.7466 |
| **Sentinel Lights** | $ 4.28 | kW | $ 20.5359 |
| **Street Lighting** | $ 0.71 | kW | $ 2.9627 |
| **Unmetered and Scattered** | $ 13.17 | kWh | $ 0.0079 |

**Retail Transmission Service Rates**

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "2013_RTSR_Adjustment_Work_Form" and instructions for distributors to complete as part of their 2013 electricity rate applications. BPI has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.8 is reproduced from the Board model and indicates the new RTSR's.

**Table 8.8: Final 2013 RTSR Rates**

| Rate Class | Unit | Proposed RTSR Network | Proposed RTSR Connection |
|---|---|---|---|
| Residential | kWh | $ 0.0084 | $ 0.0057 |
| General Service Less Than 50 kW | kWh | $ 0.0076 | $ 0.0049 |
| General Service 50 to 4,999 kW | kW | $ 2.5958 | $ 1.6850 |
| Unmetered Scattered Load | kWh | $ 0.0076 | $ 0.0049 |
| Sentinel Lighting | kW | $ 2.4240 | $ 1.5737 |
| Street Lighting | kW | $ 2.3960 | $ 1.5555 |
| Embedded Distributor | kW | $ 2.5958 | $ 1.6850 |
| | | - | - |

The RTSR Work Form can be found in Appendix B.

## Retail Service Charges

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the Retail Settlement Code (“RSC”). BPI is not proposing any new changes to the level and the rates of Retail Service charges. BPI maintains the appropriate Retail Service Costs Variance Accounts (“RCVA”) to record the difference between charges rendered to customers and retailers, and the direct incremental costs for the provision of these services.

## Wholesale Market Service Rate

The Wholesale Market Service Rate is designed to allow distributors to recover costs charged by the Independent Electricity System Operator (“IESO”) for the operation of the IESO administered markets and the operation of the IESO-controlled grid.

The Wholesale Market Service Rate is an energy based rate (per kWh). This rate only applies to those customers of a distributor who are not wholesale market participants. BPI is not proposing any new changes to the level and the rates of the Wholesale Market Service rate. BPI will be using the rate of $0.44 per kWh for its Wholesale Market Service rate, and the rate of $0.12 per kWh for the Rural or Remote Protection Plan Rate Charge. Both of these rates were approved by the Board in its Decision in EB-2013-0067.

**Specific Service Charges**

BPI is seeking the following changes and additions to the current Board Approved Specific Service Charges:

- Removal of the Arrears Certificate service charge: $15.00.
- Removal of Temporary Install/Remove Overhead- With transformer service charge: $1,000.
- Addition of the Meter Removal without Authorization service charge: $60.00.
- Addition of the Install/Remove Load Control Device after Business Hours service charge: $185.00.

BPI is using the default charges set by the Board. Further discussion can be found in Exhibit 3, Tab 3, Schedule 3.

# LOSS FACTOR

## DETERMINATION OF LOSS ADJUSTMENT FACTORS

### Total Loss Factor

BPI has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2007 to 2011. The calculations are summarized in Table 8-9 below.

**Table 8.9: Line Loss Calculation.**

| | | Historical Years | | | | | 5-Year Average |
|---|---|---|---|---|---|---|---|
| | | 2007 | 2008 | 2009 | 2010 | 2011 | |
| | ***Losses Within Distributor's System*** | | | | | | |
| **A(1)** | "Wholesale" kWh delivered to distributor (higher value) | 1,043,014,997 | 1,013,423,330 | 940,830,205 | 950,759,113 | 944,902,732 | 978,586,075 |
| **A(2)** | "Wholesale" kWh delivered to distributor (lower value) | 1,038,354,233 | 1,008,890,381 | 936,617,083 | 946,540,017 | 940,754,877 | 974,231,318 |
| **B** | Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s) | 0 | 0 | 0 | 0 | 0 | - |
| **C** | Net "Wholesale" kWh delivered to distributor = **A(2) - B** | 1,038,354,233 | 1,008,890,381 | 936,617,083 | 946,540,017 | 940,754,877 | 974,231,318 |
| **D** | "Retail" kWh delivered by distributor | 1,004,831,701 | 977,884,255 | 912,366,781 | 917,169,662 | 915,803,475 | 945,611,175 |
| **E** | Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s) | 0 | 0 | 0 | 0 | 0 | - |
| **F** | Net "Retail" kWh delivered by distributor = **D - E** | 1004831701 | 977884255 | 912366781 | 917169662 | 915803475 | 945,611,175 |
| **G** | Loss Factor in Distributor's system = **C / F** | 1.0334 | 1.0317 | 1.0266 | 1.0320 | 1.0272 | 1.0303 |
| | ***Losses Upstream of Distributor's System*** | | | | | | |
| **H** | Supply Facilities Loss Factor | 1.0045 | 1.0045 | 1.0045 | 1.0045 | 1.0045 | 1.0045 |
| | ***Total Losses*** | | | | | | |
| I | Total Loss Factor = **G x H** | 1.0380 | 1.0364 | 1.0312 | 1.0367 | 1.0319 | 1.0349 |

The supply facility loss factor (the "SFLF") shown in the above Table represents the losses on supply to BPI. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF of 1.0045 used in the calculations of the total loss factor above is based on being directly connected to the IESO-controlled grid.

As a result of this analysis, BPI is proposing to set the 2013 Total Loss Factor at 1.0349. This represents the 5 year average from 2007 to 2011.

**Total Loss Factor by Class**

Table 8.10 sets out the class-specific Loss Factors used by BPI in the calculation of commodity and other non-distribution charges for the 2013 Test Year.

**Table 8.10: Total Loss Factor by Class**

| | |
|---|---|
| **Supply Facility Loss Factor** | 1.0045 |
| | |
| **Distribution Loss Factor** | |
| Distribution Loss Factor - Secondary Metered Customer 5,000 kW | 1.0303 |
| Distribution Loss Factor - Primary Metered Customer < 5,000kW | 1.0200 |
| | |
| **Total Loss Factor** | |
| Total Loss Factor - Secondary Metered Customer < 5,000kW | 1.0349 |
| Total Loss Factor - Primary Metered Customer < 5,000kW | 1.0246 |

**Materiality Analysis on Distribution Losses**

BPI's Distribution Loss Adjustment factor is 3.03%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, BPI is not required to provide an explanation of, or justification for, its loss adjustment factor.

# RATE MITIGATION

The Sentinel light rate class is the only rate class that has a total bill increase above the 10% threshold. The reason for this increase is to move to revenues for this class to be more in line with costs. As a result, BPI does not believe a rate mitigation plan is required for the Sentinel light rate class.

# EXISTING RATE CLASSES

## Residential

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

## General Service Less Than 50kW

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

## General Service Greater Than 50 kW

This classification refers to a non-residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 50 kW but less than 5,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

## Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load.

**Sentinel Lighting**

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

**Street Lighting**

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Board street lighting load shape template.

**MicroFit Generator**

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's MicroFit program and connected to the distributor's distribution system.

**Embedded Distributor**

This classification refers to an account of a distributor who is not a wholesale market participant and that is provided electricity by a host distributor.

**Standby Power**

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service.

# EXISTING RATE SCHEDULE

BPI has attached the Board's Decision and Order from its 2012 Rate Application (EB-2011-0147) which contains a complete schedule of existing rates.

## EXISTING RATE SCHEDULE:

### MONTHLY RATES & CHARGES

**Residential**

| | |
|---|---|
| Service Charge | 11.46 |
| Distribution Volumetric Rate | 0.0138 per kWh |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.0005) per kWh |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2012) – effective until April 30, 2013 | 0.0013 per kWh |
| Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2013 | (0.0070) per kWh |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers | (0.0015) per kWh |
| Retail Transmission Rate – Network Service Rate | 0.0080 per kWh |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | 0.0055 per kWh |
| Wholesale Market Service Rate | 0.0052 per kWh |
| Rural Rate Protection Charge | 0.0011 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**General Service Less Than 50 kW**

| | |
|---|---|
| Service Charge | 24.81 |
| Distribution Volumetric Rate | 0.0065 per kWh |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.0002) per kWh |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/ Shared Savings Mechanism (SSM) Recovery (2012) – effective until April 30, 2013 | 0.0004 per kWh |
| Rate Rider for Deferral/Variance Account Disposition (2012) – - effective until April 30, 2013 | (0.0052) per kWh |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until April 30, 2013 Applicable only for Non-RPP Customers | (0.0015) per kWh |
| Retail Transmission Rate – Network Service Rate | 0.0072 per kWh |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | 0.0048 per kWh |
| Wholesale Market Service Rate | 0.0052 per kWh |
| Rural Rate Protection Charge | 0.0011 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**General Service 50 to 4,999 kW**

| | |
|---|---|
| Service Charge | 293.71 |
| Distribution Volumetric Rate | 2.6043 per kW |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.0609) per kW |

| | |
|---|---|
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2012) – effective until April 30, 2013 | 0.0633 per kW |
| Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013 | (1.8203) per kW |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until April 30, 2013Applicable only for Non-RPP Customers | (0.5790) per kW |
| Retail Transmission Rate – Network Service Rate | 2.4601 per kW |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | 1.6398 per kW |
| Wholesale Market Service Rate | 0.0052 per kWh |
| Rural Rate Protection Charge | 0.0011 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**Unmetered Scattered Load**

| | |
|---|---|
| Service Charge (per connection) | 12.06 |
| Distribution Volumetric Rate | 0.0072 per kWh |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.0006) per kWh |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/ Shared Savings Mechanism (SSM) Recovery (2012) – effective until April 30, 2013 | 0.0093 per kWh |
| Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2013 | (0.0096) per kWh |
| Retail Transmission Rate – Network Service Rate | 0.0072 per kWh |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | 0.0048 per kWh |
| Wholesale Market Service Rate | 0.0052 per kWh |
| Rural Rate Protection Charge | 0.0011 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**Standby Power - APPROVED ON AN INTERIM BASIS**

| | |
|---|---|
| Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility) | 1.6729 per kW |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.0284) per kW |

**Street Lighting**

| | |
|---|---|
| Service Charge (per connection) | 0.65 |
| Distribution Volumetric Rate | 2.7127 per kW |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.0984) per kW |
| Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013 | (1.8739) per kW |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non RPP Customers | (0.4810) per kW |
| Retail Transmission Rate – Network Service Rate | 2.2708 per kW |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | 1.5138 per kW |
| Wholesale Market Service Rate | 0.0052 per kW |
| Rural Rate Protection Charge | 0.0011 per kW |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**Sentinel Lighting**

| | |
|---|---|
| Service Charge (per connection) | 2.32 |

| | |
|---|---|
| Distribution Volumetric Rate | 11.1228 per kW |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.3971) per kW |
| Rate Rider for Deferral/Variance Account Disposition (2012) - effective until April 30, 2013 | (4.1579) per kW |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers | (0.4410) per kW |
| Retail Transmission Rate – Network Service Rate | 2.2973 per kW |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | 1.5315 per kW |
| Wholesale Market Service Rate | 0.0052 per kWh |
| Rural Rate Protection Charge | 0.0011 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**MicroFit Generator Service Classification**

| | |
|---|---|
| Service Charge | 5.25 |

**Embedded Distributor Service Classification**

| | |
|---|---|
| Service Charge | 293.71 |
| Distribution Volumetric Rate | 1.7488 per kW |
| Rate Rider for Tax Change – effective until April 30, 2013 | (0.0307) per kW |
| Retail Transmission Rate – Network Service Rate | 2.4601 per kW |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | 1.6398 per Kw |

**Specific Service Charges**

**Allowances**

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

**Customer Administration**

| | |
|---|---|
| Arrears certificate | 15.00 |
| Easement letter | 15.00 |
| Credit reference/credit check (plus credit agency costs) | 15.00 |
| Returned cheque charge (plus bank charges) | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | 30.00 |

**Non-Payment of Account**

| | |
|---|---|
| Late Payment - per month | 1.50 % |
| Late Payment - per annum | 19.56 % |
| Collection of account charge – no disconnection | 30.00 |
| Disconnect/Reconnect charge - At Meter – during regular hours | 65.00 |
| Disconnect/Reconnect charge - At Meter – after regular hours | 185.00 |
| Disconnect/Reconnect charge - At Pole – during regular hours | 185.00 |
| Disconnect/Reconnect charge - At Pole – after regular hours | 415.00 |

| | |
|---|---|
| Install/Remove load control device –during regular hours | 65.00 |
| Temporary Service – Install and remove – overhead – no transformer | 500.00 |
| Temporary Service – Install and remove – underground –no transformer | 300.00 |
| Temporary Service – Install and remove – overhead – with transformer | 1000.00 |
| Specific Charge for Access to the Power Poles – per pole/year | 22.35 |

**Retail Service Charges (if applicable)**

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

**Loss Factors**

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0420 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0316 |

## PROPOSED RATE CLASSES

BPI is not proposing any additional rate classes.

# SCHEDULE OF PROPOSED RATES & CHARGES

## MONTHLY RATES & CHARGES:

### Residential

| | |
|---|---|
| Service Charge | 12.52 |
| Distribution Volumetric Rate | 0.0151 per kWh |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery | 0.0003 per kWh |
| Rate Rider for Deferral/Variance Account | (0.0039) per kWh |
| Rate Rider for Global Adjustment Sub-Account Disposition | 0.0018 per kWh |
| Retail Transmission Rate – Network Service Rate | 0.0084 per kWh |
| Retail Transmission Rate – Connection Service Rate | 0.0057 per kWh |
| Smart Meter Disposition Rate Rider (SMDR) | (0.19) |
| Stranded Meter Recovery Rate Rider (SMRR) | 1.77 |
| Rate Rider for Smart Metering Entity Charge - effective until Oct. 31, 2018 | 0 .79 |
| Wholesale Market Service Rate | 0.0044 per kWh |
| Rural Rate Protection Charge | 0.0012 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

### General Service Less Than 50 kW

| | |
|---|---|
| Service Charge | 27.13 |
| Distribution Volumetric Rate | 0.0071 per kWh |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery | 0.0002 per kWh |
| Rate Rider for Deferral/Variance Account | (0.0039) per kWh |
| Rate Rider for Global Adjustment Sub-Account Disposition | 0.0018 per kWh |
| Retail Transmission Rate – Network Service Rate | 0.0076 per kWh |
| Retail Transmission Rate – Connection Service Rate | 0.0049 per kWh |
| Smart Meter Disposition Rate Rider (SMDR) | (0.77) |
| Stranded Meter Recovery Rate Rider (SMRR) | 1.75 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | 0.79 |
| Wholesale Market Service Rate | 0.0044 per kWh |
| Rural Rate Protection Charge | 0.0012 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

### General Service 50 to 4,999 kW

| | |
|---|---|
| Service Charge | 320.78 |
| Distribution Volumetric Rate | 2.8142 per kW |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery | 0.0157 per kW |
| Rate Rider for Deferral/Variance Account | (1.5264) per kW |
| Rate Rider for Global Adjustment Sub-Account Disposition | 0.7080 per kW |
| Retail Transmission Rate – Network Service Rate | 2.5958 per kW |
| Retail Transmission Rate – Connection Service Rate | 1.6850 per kW |
| Wholesale Market Service Rate | 0.0044 per kWh |
| Rural Rate Protection Charge | 0.0012 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

### Unmetered Scattered load

| | |
|---|---|
| Service Charge (per connection) | 13.17 |
| Distribution Volumetric Rate | 0.0079 per kWh |
| Rate Rider for Deferral/Variance Account | (0.0039) per kWh |

| | |
|---|---|
| Rate Rider for Global Adjustment Sub-Account Disposition | 0.0018 per kWh |
| Retail Transmission Rate – Network Service Rate | 0.0076 per kWh |
| Retail Transmission Rate – Connection Service Rate | 0.0049 per kWh |
| Wholesale Market Service Rate | 0.0044 per kWh |
| Rural Rate Protection Charge | 0.0012 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**Street Lighting**

| | |
|---|---|
| Service Charge (per connection) | 0.71 |
| Distribution Volumetric Rate | 2.9627 per kW |
| Rate Rider for Deferral/Variance Account | (1.2513) per kW |
| Rate Rider for Global Adjustment Sub-Account Disposition | 0.5804 per kW |
| Retail Transmission Rate – Network Service Rate | 2.3960 per kW |
| Retail Transmission Rate – Connection Service Rate | 1.5555 per kW |
| Wholesale Market Service Rate | 0.0044 per kWh |
| Rural Rate Protection Charge | 0.0012 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**MicroFIT Generator Service Classification**

| | |
|---|---|
| Service Charge | 5.40 |

**Sentinel Lighting Service Classification**

| | |
|---|---|
| Service Charge (per connection) | 4.28 |
| Distribution Volumetric Rate | 20.5359 per kW |
| Rate Rider for Deferral/Variance Account | (1.2707) per kW |
| Rate Rider for Global Adjustment Sub-Account Disposition | 0.5894 per kW |
| Retail Transmission Rate – Network Service Rate | 2.4240 per kW |
| Retail Transmission Rate – Connection Service Rate | 1.5737 per kW |
| Wholesale Market Service Rate | 0.0044 per kWh |
| Rural Rate Protection Charge | 0.0012 per kWh |
| Standard Supply Service – Administrative Charge (if applicable) | 0.25 |

**Embedded Distributor Service**

| | |
|---|---|
| Service Charge | 293.34 |
| Distribution Volumetric Rate | 1.7466 per kW |
| Retail Transmission Rate – Network Service Rate | 2.5958 per kW |
| Retail Transmission Rate – Connection Service Rate | 1.6850 per Kw |

**Specific Service Charges**

**Customer Administration**

| | |
|---|---|
| Easement letter | 15.00 |
| Credit reference/credit check (plus credit agency costs) | 15.00 |
| Returned cheque charge (plus bank charges) | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | 30.00 |
| Meter Dispute Charge | 30.00 |
| plus Measurement Canada fees (if meter found correct) | 60.00 |

**Non-Payment of Account**

| | |
|---|---|
| Late Payment - per month | 1.50 % |
| Late Payment - per annum | 19.56 % |
| Collection of account charge – no disconnection | 30.00 |
| Disconnect/Reconnect charge - At Meter – during regular hours | 65.00 |
| Disconnect/Reconnect charge - At Meter – after regular hours | 185.00 |
| Disconnect/Reconnect charge - At Pole – during regular hours | 185.00 |
| Disconnect/Reconnect charge - At Pole – after regular hours | 415.00 |
| Install/Remove load control device – during regular hours | 65.00 |
| Install/Remove load control device – after regular hours | 185.00 |
| Temporary Service – Install and remove – overhead – no transformer | 500.00 |
| Temporary Service – Install and remove – underground – no transformer | 300.00 |
| Specific Charge for Access to the Power Poles – per pole/year | 22.35 |

**Allowances**

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

**Loss Factors**

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0349 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0246 |

## RECONCILIATION OF RATE CLASS REVENUE

The following Tables provide reconciliation between the 2013 distribution rate calculations based on the 2013 Proposed Rates and the total base revenue required.

### Table 8.11: Revenue Reconciliation (Appendix 2-V)

| Rate Class | Customers/ Connections | Number of Customers/Connections | | | Test Year Consumption | | Proposed Rates | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Start of Test Year | End of Test Year | Average | kWh | kW | Monthly Service Charge | Volumetric | |
| | | | | | | | | kWh | kW |
| Residential | Customers | 35,242.24 | 35,699.33 | 35,364 | 280,913,502 | | $ 12.52 | $ 0.0151 | |
| GS < 50 kW | Customers | 2,687.52 | 2,718.39 | 2,764 | 97,535,297 | | $ 27.13 | $ 0.0071 | |
| GS > 50 to 4,999 kW | Customers | 421.10 | 424.23 | 420 | 531,977,718 | 1,354,270 | $ 320.78 | | $ 2.8142 |
| Large Use | | | | - | | | | | |
| Streetlighting | Connections | 10,238.03 | 10,458.73 | 10,355 | 7,553,004 | 23,455 | $ 0.71 | | $ 2.9627 |
| Sentinel Lighting | Connections | 641.72 | 657.83 | 635 | 443,490 | 1,356 | $ 4.28 | | $ 20.5359 |
| Unmetered Scattered Load | Customers | 438.13 | 431.36 | 437 | 1,454,727 | | $ 13.17 | $ 0.0079 | |
| Standby Power | Customers | | | - | | | | | |
| Embedded Distributor Class | Customers | 1.00 | 1.00 | 3 | | 155,806 | $ 293.34 | | $ 1.7466 |
| etc. | | | | - | | | | | |
| | | | | - | | | | | |
| | | | | - | | | | | |
| | | | | - | | | | | |

| Rate Class | Class Specific Revenue | Transformer Allowance | Total | Difference |
|---|---|---|---|---|
| Residential | $ 9,545,328 | | $ 9,545,328 | -$ 9,510 |
| GS < 50 kW | $ 1,592,778 | $ 126 | $ 1,592,904 | $ 525 |
| GS > 50 to 4,999 | $ 4,983,913 | $ 443,111 | $ 5,427,024 | -$ 44 |
| Large Use | | | $ - | $ - |
| Streetlighting | $ 157,703 | | $ 157,703 | -$ 11 |
| Sentinel Lighting | $ 60,496 | | $ 60,496 | $ 26 |
| Unmetered Scatte | $ 80,547 | | $ 80,547 | -$ 45 |
| Standby Power | | | $ - | $ - |
| Embedded Distrib | $ 282,689 | | $ 282,689 | -$ 2 |
| etc. | | | $ - | $ - |
| | | | $ - | $ - |
| | | | $ - | $ - |
| | | | $ - | $ - |
| **Total** | $ 16,703,454 | $ 443,238 | $ 17,146,692 | -$ 9,060 |

The following Table 8.12 compares 2013 Distribution Revenues per class at the proposed rates with 2013 Distribution Revenues per class at current rates.

**Table 8.12: 2013 Revenues on Current and Proposed Rates**

| Class | Distribution Revenues at Current Rates | Distribution Revenues on Proposed Rates |
|---|---|---|
| **Residential** | 8,739,824 | $ 9,545,328 |
| **GS < 50 kW** | 1,456,779 | $ 1,592,778 |
| **GS 50 to 4999** | 4,563,334 | $ 4,983,913 |
| **Embedded Distributor** | 283,047 | $ 282,689 |
| **Sentinel Lights** | 32,766 | $ 60,496 |
| **Street Lighting** | 144,395 | $ 157,703 |
| **Unmetered and Scattere** | 73,750 | $ 80,547 |
| **Total** | **15,293,896** | **$ 16,703,454** |

# RATE AND BILL IMPACTS

Appendix A to this Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are shown using the applicable current approved rates and the proposed 2013 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

# APPENDIX A

# BILL IMPACTS

# Bill Impacts

**Customer Class:** **Residential**

**Consumption** **800** **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed afte

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | Proposed Rate ($) | Proposed Volume | Proposed Charge ($) | Impact $ Change | Impact % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | $ 11.4600 | 1 | $ 11.46 | $ 12.5200 | 1 | $ 12.52 | $ 1.06 | 9.25% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| Smart Meter Disposition Rate Rider | | | 1 | $ - | -$ 0.1900 | 1 | -$ 0.19 | -$ 0.19 | |
| Smart Metering Entity Charge | | | 1 | $ - | $ 0.7880 | 1 | $ 0.79 | $ 0.79 | |
| Stranded Meter Recovery Rate Rider | | | 1 | $ - | $ 1.7600 | 1 | $ 1.76 | $ 1.76 | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | | $ 0.0138 | 800 | $ 11.04 | $ 0.0151 | 800 | $ 12.08 | $ 1.04 | 9.42% |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| LRAM & SSM Rate Rider | | $ 0.0013 | 800 | $ 1.04 | $ 0.0003 | 800 | $ 0.21 | -$ 0.83 | -79.41% |
| Tax change | | -$ 0.0005 | 800 | -$ 0.40 | | 800 | $ - | $ 0.40 | -100.00% |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| **Sub-Total A** | | | | $ 23.14 | | | $ 27.17 | **$ 4.03** | **17.43%** |
| Deferral/Variance Account Disposition Rate Rider | | -$ 0.0070 | 800 | -$ 5.60 | -$ 0.0039 | 800 | -$ 3.11 | $ 2.49 | -44.49% |
| Global Adjustment - Non RPP | | | 800 | $ - | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| | | | 800 | $ - | | 800 | $ - | $ - | |
| Low Voltage Service Charge | | | 800 | $ - | | 800 | $ - | $ - | |
| Smart Meter Entity Charge | | | | | | 800 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 17.54** | | | **$ 24.06** | **$ 6.52** | **37.19%** |
| RTSR - Network | | $ 0.0080 | 834 | $ 6.67 | $ 0.0084 | 828 | $ 6.95 | $ 0.29 | 4.28% |
| RTSR - Line and Transformation Connection | | $ 0.0055 | 834 | $ 4.58 | $ 0.0057 | 828 | $ 4.72 | $ 0.13 | 2.93% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 28.79** | | | **$ 35.74** | **$ 6.94** | **24.11%** |
| Wholesale Market Service Charge (WMSC) | | $ 0.0052 | 834 | $ 4.33 | $ 0.0044 | 828 | $ 3.64 | -$ 0.69 | -15.96% |
| Rural and Remote Rate Protection (RRRP) | | $ 0.0011 | 834 | $ 0.92 | $ 0.0012 | 828 | $ 0.99 | $ 0.08 | 8.35% |
| Standard Supply Service Charge | | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0070 | 834 | $ 5.84 | $ 0.0070 | 828 | $ 5.80 | -$ 0.04 | -0.68% |
| Energy - RPP - Tier 1 | | $ 0.0780 | 600 | $ 46.80 | $ 0.0780 | 600 | $ 46.80 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.0910 | 234 | $ 21.26 | $ 0.0910 | 228 | $ 20.74 | -$ 0.52 | -2.43% |
| TOU - Off Peak | | $ 0.0670 | 534 | $ 35.74 | $ 0.0670 | 530 | $ 35.50 | -$ 0.24 | -0.68% |
| TOU - Mid Peak | | $ 0.1040 | 150 | $ 15.60 | $ 0.1040 | 149 | $ 15.50 | -$ 0.11 | -0.68% |
| TOU - On Peak | | $ 0.1240 | 150 | $ 18.61 | $ 0.1240 | 149 | $ 18.48 | -$ 0.13 | -0.68% |
| | | | | | | | | | |
| **Total Bill on RPP (before Taxes)** | | | | **$ 108.19** | | | **$ 113.96** | **$ 5.77** | **5.33%** |
| HST | | 13% | | $ 14.06 | 13% | | $ 14.81 | $ 0.75 | 5.33% |
| **Total Bill** (including HST) | | | | $ 122.25 | | | $ 128.77 | $ 6.52 | 5.33% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 12.23 | | | -$ 12.88 | -$ 0.65 | 5.31% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 110.02** | | | **$ 115.89** | **$ 5.87** | **5.34%** |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 110.09** | | | **$ 115.90** | **$ 5.81** | **5.28%** |
| HST | | 13% | | $ 14.31 | 13% | | $ 15.07 | $ 0.76 | 5.28% |
| **Total Bill** (including HST) | | | | $ 124.40 | | | $ 130.96 | $ 6.57 | 5.28% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 12.44 | | | -$ 13.10 | -$ 0.66 | 5.31% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 111.96** | | | **$ 117.86** | **$ 5.91** | **5.28%** |

| | | |
|---|---|---|
| **Loss Factor (%)** | 4.20% | 3.49% |

# Bill Impacts

**Customer Class:** **GS<50**

**Consumption** **2000** **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed afte

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | Proposed Rate ($) | Proposed Volume | Proposed Charge ($) | Impact $ Change | Impact % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | | $ 24.8100 | 1 | $ 24.81 | $ 27.1300 | 1 | $ 27.13 | $ 2.32 | 9.35% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| Smart Meter Disposition Rate Rider | | | 1 | $ - | -$ 0.7700 | 1 | -$ 0.77 | -$ 0.77 | |
| Smart Metering Entity Charge | | | 1 | $ - | $ 0.7880 | 1 | $ 0.79 | $ 0.79 | |
| Stranded Meter Recovery Rate Rider | | | 1 | $ - | $ 1.7500 | 1 | $ 1.75 | $ 1.75 | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | | $ 0.0065 | 2000 | $ 13.00 | $ 0.0071 | 2000 | $ 14.20 | $ 1.20 | 9.23% |
| Smart Meter Disposition Rider | | | 1 | $ - | | 1 | $ - | $ - | |
| LRAM & SSM Rate Rider | | $ 0.0004 | 2000 | $ 0.80 | $ 0.0002 | 2000 | $ 0.45 | -$ 0.35 | -43.50% |
| Tax change | | -$ 0.0002 | 2000 | -$ 0.40 | | 2000 | $ - | $ 0.40 | -100.00% |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| **Sub-Total A** | | | | $ 38.21 | | | $ 43.55 | **$ 5.34** | **13.98%** |
| Deferral/Variance Account Disposition Rate Rider | | -$ 0.0052 | 2000 | -$ 10.40 | -$ 0.0039 | 2000 | -$ 7.77 | $ 2.63 | -25.27% |
| Global Adjustment - Non RPP | | | 2000 | $ - | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| | | | 2000 | $ - | | 2000 | $ - | $ - | |
| Low Voltage Service Charge | | | 2000 | $ - | | 2000 | $ - | $ - | |
| Smart Meter Entity Charge | | | | | | 2000 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 27.81** | | | **$ 35.78** | **$ 7.97** | **28.65%** |
| RTSR - Network | | $ 0.0072 | 2084 | $ 15.00 | $ 0.0076 | 2070 | $ 15.73 | $ 0.73 | 4.84% |
| RTSR - Line and Transformation Connection | | $ 0.0048 | 2084 | $ 10.00 | $ 0.0049 | 2070 | $ 10.14 | $ 0.14 | 1.39% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 52.82** | | | **$ 61.65** | **$ 8.83** | **16.72%** |
| Wholesale Market Service Charge (WMSC) | | $ 0.0052 | 2084 | $ 10.84 | $ 0.0044 | 2070 | $ 9.11 | -$ 1.73 | -15.96% |
| Rural and Remote Rate Protection (RRRP) | | $ 0.0011 | 2084 | $ 2.29 | $ 0.0012 | 2070 | $ 2.48 | $ 0.19 | 8.35% |
| Standard Supply Service Charge | | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | | $ 0.0070 | 2084 | $ 14.59 | $ 0.0070 | 2070 | $ 14.49 | -$ 0.10 | -0.68% |
| Energy - RPP - Tier 1 | | $ 0.0780 | 600 | $ 46.80 | $ 0.0780 | 600 | $ 46.80 | $ - | 0.00% |
| Energy - RPP - Tier 2 | | $ 0.0910 | 1484 | $ 135.04 | $ 0.0910 | 1470 | $ 133.75 | -$ 1.29 | -0.96% |
| TOU - Off Peak | | $ 0.0670 | 1334 | $ 89.36 | $ 0.0670 | 1325 | $ 88.75 | -$ 0.61 | -0.68% |
| TOU - Mid Peak | | $ 0.1040 | 375 | $ 39.01 | $ 0.1040 | 373 | $ 38.75 | -$ 0.27 | -0.68% |
| TOU - On Peak | | $ 0.1240 | 375 | $ 46.51 | $ 0.1240 | 373 | $ 46.20 | -$ 0.32 | -0.68% |
| | | | | | | | | | |
| **Total Bill on RPP (before Taxes)** | | | | **$ 262.63** | | | **$ 268.53** | **$ 5.90** | **2.25%** |
| HST | | 13% | | $ 34.14 | 13% | | $ 34.91 | $ 0.77 | 2.25% |
| **Total Bill** (including HST) | | | | $ 296.77 | | | $ 303.44 | $ 6.67 | 2.25% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 29.68 | | | -$ 30.34 | -$ 0.66 | 2.22% |
| **Total Bill on RPP (including OCEB)** | | | | **$ 267.09** | | | **$ 273.10** | **$ 6.01** | **2.25%** |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 255.67** | | | **$ 261.68** | **$ 6.00** | **2.35%** |
| HST | | 13% | | $ 33.24 | 13% | | $ 34.02 | $ 0.78 | 2.35% |
| **Total Bill** (including HST) | | | | $ 288.91 | | | $ 295.70 | $ 6.78 | 2.35% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 28.89 | | | -$ 29.57 | -$ 0.68 | 2.35% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 260.02** | | | **$ 266.13** | **$ 6.10** | **2.35%** |

**Loss Factor (%)** Current: 4.20% Proposed: 3.49%

# Bill Impacts

**Customer Class:** **GS>50**

| | | |
|---|---|---|
| **Consumption** | 100 | **kW** |
| **Consumption** | 39,339 | **kWh** |

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after (

| | **Charge Unit** | **Current Board-Approved** Rate ($) | Volume | Charge ($) | **Proposed** Rate ($) | Volume | Charge ($) | **Impact** $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 293.7100 | 1 | $ 293.71 | $ 320.7800 | 1 | $ 320.78 | $ 27.07 | 9.22% |
| Smart Meter Rate Adder | Monthly | | 1 | $ - | | 1 | $ - | $ - | |
| Stranded Meter Recovery | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 2.6043 | 100 | $ 260.43 | $ 2.8142 | 100 | $ 281.42 | $ 20.99 | 8.06% |
| Smart Meter Disposition Rider | Monthly | | 1 | $ - | $ - | 1 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ 0.0633 | 100 | $ 6.33 | $ 0.0157 | 100 | $ 1.57 | -$ 4.76 | -75.26% |
| Tax change | per kW | -$ 0.0609 | 100 | -$ 6.09 | | 100 | $ - | $ 6.09 | -100.00% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| **Sub-Total A** | | | | $ 554.38 | | | $ 603.77 | **$ 49.39** | **8.91%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | -$ 1.8203 | 100 | -$ 182.03 | -$ 1.5264 | 100 | -$ 152.64 | $ 29.39 | -16.14% |
| Global Adjustment - Non RPP | per kWh | -$ 0.5790 | 100 | -$ 57.90 | $ 0.7080 | 100 | $ 70.80 | $ 128.70 | -222.27% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| Low Voltage Service Charge | | | | $ - | | 0 | $ - | $ - | |
| Smart Meter Entity Charge | | | | | | 0 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 314.45** | | | **$ 521.92** | **$ 207.47** | **65.98%** |
| RTSR - Network | per kW | $ 2.4601 | 104 | $ 256.34 | $ 2.5958 | 103.49 | $ 268.64 | $ 12.30 | 4.80% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6398 | 104 | $ 170.87 | $ 1.6850 | 103.49 | $ 174.38 | $ 3.51 | 2.06% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 741.66** | | | **$ 964.94** | **$ 223.28** | **30.11%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0052 | 40991 | $ 213.15 | $ 0.0044 | 40711.9 | $ 179.13 | -$ 34.02 | -15.96% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0011 | 40991 | $ 45.09 | $ 0.0012 | 40711.9 | $ 48.85 | $ 3.76 | 8.35% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | per kWh | $ 0.0070 | 40991 | $ 286.94 | $ 0.0070 | 40711.9 | $ 284.98 | -$ 1.96 | -0.68% |
| Energy - RPP - Tier 1 | | $ 0.0750 | 0 | $ - | $ 0.0750 | 0 | $ - | $ - | |
| Energy - RPP - Tier 2 | | $ 0.0880 | 0 | $ - | $ 0.0880 | 0 | $ - | $ - | |
| Energy - COP | | $0.08717 | 40991 | $ 3,573.21 | $0.08717 | 40711.9 | $ 3,548.86 | -$ 24.35 | -0.68% |
| **Total Bill** | | | | **$ 4,860.30** | | | **$ 5,027.02** | **$ 166.72** | **3.43%** |
| HST | | 13% | | $ 631.84 | 13% | | $ 653.51 | $ 21.67 | 3.43% |
| **Total Bill** (including HST) | | | | $ 5,492.14 | | | $ 5,680.53 | $ 188.39 | 3.43% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 549.21 | | | -$ 568.05 | -$ 18.84 | 3.43% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 4,942.93** | | | **$ 5,112.48** | **$ 169.55** | **3.43%** |

**Loss Factor (%)** Current: 4.20% Proposed: 3.49%

## Bill Impacts

**Customer Class:** **Street lights**

| | | | | |
|---|---|---|---|---|
| **Consumption** | 1 | kW | ◉ May 1 - October 31 | ○ November 1 - April 30 (Select this radio button for applications filed after ( |
| **Consumption** | 322 | kWh | | |

| | Charge Unit | Current Board-Approved Rate ($) | Current Volume | Current Charge ($) | Proposed Rate ($) | Proposed Volume | Proposed Charge ($) | Impact $ Change | Impact % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 0.6500 | 1 | $ 0.65 | $ 0.71 | 1 | $ 0.71 | $ 0.06 | 9.22% |
| Smart Meter Rate Adder | Monthly | | 1 | $ - | $ - | 1 | $ - | $ - | |
| Stranded Meter Recovery | | | 1 | $ - | $ - | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 2.7127 | 1 | $ 2.71 | $ 2.9627 | 1 | $ 2.96 | $ 0.25 | 9.22% |
| Smart Meter Disposition Rider | Monthly | | 1 | $ - | $ - | 1 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | | 1 | $ - | $ - | 1 | $ - | $ - | |
| Tax change | per kW | -$ 0.0984 | 1 | -$ 0.10 | $ - | 1 | $ - | $ 0.10 | -100.00% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| **Sub-Total A** | | | | $ 3.26 | | | $ 3.67 | **$ 0.41** | **12.51%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | -$ 1.8739 | 1 | -$ 1.87 | -$ 1.2513 | 1 | -$ 1.25 | $ 0.62 | -33.22% |
| Global Adjustment - Non RPP | per kW | -$ 0.4810 | 1 | -$ 0.48 | $ 0.5804 | 1 | $ 0.58 | $ 1.06 | -220.66% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| Low Voltage Service Charge | | | | $ - | | 0 | $ - | $ - | |
| Smart Meter Entity Charge | | | | | | 0 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 0.91** | | | **$ 3.00** | **$ 2.09** | **230.07%** |
| RTSR - Network | per kW | $ 2.2708 | 1 | $ 2.37 | $ 2.3960 | 1.0349 | $ 2.48 | $ 0.11 | 4.79% |
| RTSR - Line and Transformation Connection | per kW | $ 1.5138 | 1 | $ 1.58 | $ 1.5555 | 1.0349 | $ 1.61 | $ 0.03 | 2.05% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 4.85** | | | **$ 7.09** | **$ 2.24** | **46.12%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0052 | 336 | $ 1.74 | $ 0.0044 | 333 | $ 1.47 | -$ 0.28 | -15.96% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0011 | 336 | $ 0.37 | $ 0.0012 | 333 | $ 0.40 | $ 0.03 | 8.35% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | per kWh | $ 0.0070 | 336 | $ 2.35 | $ 0.0070 | 333 | $ 2.33 | -$ 0.02 | -0.68% |
| Energy - RPP - Tier 1 | | $ 0.0750 | 0 | $ - | $ 0.0750 | 0 | $ - | $ - | |
| Energy - RPP - Tier 2 | | $ 0.0880 | 0 | $ - | $ 0.0880 | 0 | $ - | $ - | |
| Energy - COP | | $0.08717 | 336 | $ 29.25 | $0.08717 | 333 | $ 29.05 | -$ 0.20 | -0.68% |
| **Total Bill** | | | | **$ 38.81** | | | **$ 40.59** | **$ 1.78** | **4.57%** |
| HST | | 13% | | $ 5.05 | 13% | | $ 5.28 | $ 0.23 | 4.57% |
| **Total Bill** (including HST) | | | | $ 43.86 | | | $ 45.86 | $ 2.01 | 4.57% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 4.39 | | | -$ 4.59 | -$ 0.20 | 4.56% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 39.47** | | | **$ 41.27** | **$ 1.81** | **4.58%** |

**Loss Factor (%)** 4.20% 3.49%

# Bill Impacts

**Customer Class:** **Embedded Distributor**

**Consumption** 166168 kW  ◉ May 1 - October 31  ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31
**Consumption** 78857860 kWh

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | Proposed Rate ($) | Proposed Volume | Proposed Charge ($) | Impact $ Change | Impact % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 293.7100 | 1 | $ 293.71 | $ 293.3400 | 1 | $ 293.34 | -$ 0.37 | -0.13% |
| Smart Meter Rate Adder | Monthly | | 1 | $ - | | 1 | $ - | $ - | |
| Stranded Meter Recovery | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 1.7488 | 166168 | $ 290,594.60 | $ 1.7466 | 166168 | $ 290,229.03 | -$ 365.57 | -0.13% |
| Smart Meter Disposition Rider | Monthly | | 1 | $ - | $ - | 1 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | $ - | 166168 | $ - | $ - | 166168 | $ - | $ - | |
| Tax change | per kW | -$ 0.0307 | 166168 | -$ 5,101.36 | $ - | 166168 | $ - | $ 5,101.36 | -100.00% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| **Sub-Total A** | | | | $ 285,786.95 | | | $ 290,522.37 | **$ 4,735.42** | **1.66%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | $ - | 166168 | $ - | | 166168 | $ - | $ - | |
| Global Adjustment - Non RPP | per kW | $ - | 166168 | $ - | | 166168 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| Low Voltage Service Charge | | | | $ - | | 0 | $ - | $ - | |
| Smart Meter Entity Charge | | | | | | 0 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 285,786.95** | | | **$ 290,522.37** | **$ 4,735.42** | **1.66%** |
| RTSR - Network | per kW | $ 2.4601 | 166168 | $ 408,789.90 | $ 2.5958 | 166168 | $ 431,338.89 | $ 22,549.00 | 5.52% |
| RTSR - Line and Transformation Connection | per kW | $ 1.6398 | 166168 | $ 272,482.29 | $ 1.6850 | 166168 | $ 279,993.08 | $ 7,510.79 | 2.76% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 967,059.13** | | | **$ 1,001,854.34** | **$ 34,795.21** | **3.60%** |
| Wholesale Market Service Charge (WMSC) | per kWh | | 78857860 | $ - | | 78857860 | $ - | $ - | |
| Rural and Remote Rate Protection (RRRP) | per kWh | | 78857860 | $ - | | 78857860 | $ - | $ - | |
| Standard Supply Service Charge | Monthly | | 1 | $ - | | 1 | $ - | $ - | |
| Debt Retirement Charge (DRC) | per kWh | | 78857860 | $ - | | 78857860 | $ - | $ - | |
| Energy - RPP - Tier 1 | | $ 0.0740 | 0 | $ - | $ 0.0740 | 0 | $ - | $ - | |
| Energy - RPP - Tier 2 | | $ 0.0870 | 0 | $ - | $ 0.0870 | 0 | $ - | $ - | |
| Energy - COP | | $0.08717 | 78857860 | $ 6,874,039.66 | $0.08717 | 78857860 | $ 6,874,039.66 | $ - | 0.00% |
| | | | | | | | | | |
| | | | | | | | | | |
| **Total Bill on TOU (before Taxes)** | | | | **$ 7,841,098.79** | | | **$ 7,875,894.00** | **$ 34,795.21** | **0.44%** |
| HST | | 13% | | $ 1,019,342.84 | 13% | | $ 1,023,866.22 | $ 4,523.38 | 0.44% |
| **Total Bill** (including HST) | | | | $ 8,860,441.63 | | | $ 8,899,760.22 | $ 39,318.59 | 0.44% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 886,044.16 | | | -$ 889,976.02 | -$ 3,931.86 | 0.44% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 7,974,397.47** | | | **$ 8,009,784.20** | **$ 35,386.73** | **0.44%** |

**Loss Factor (%)** Current: 0.00% Proposed: 0.00%

# Bill Impacts

**Customer Class:** **Sentinel Lights**

| | | | |
|---|---|---|---|
| **Consumption** | 1 | **kW** | ◉ May 1 - October 31 ◯ November 1 - April 30 (Select this radio button for applications filed after ( |
| **Consumption** | 150 | **kWh** | |

| | Charge Unit | Current Board-Approved Rate ($) | Current Board-Approved Volume | Current Board-Approved Charge ($) | Proposed Rate ($) | Proposed Volume | Proposed Charge ($) | Impact $ Change | Impact % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 2.3200 | 1 | $ 2.32 | $ 4.2834 | 1 | $ 4.28 | $ 1.96 | 84.63% |
| Smart Meter Rate Adder | Monthly | $ - | 1 | $ - | $ - | 1 | $ - | $ - | |
| Stranded Meter Recovery | | | 1 | $ - | $ - | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kW | $ 11.1228 | 1 | $ 11.12 | $ 20.5359 | 1 | $ 20.54 | $ 9.41 | 84.63% |
| Smart Meter Disposition Rider | Monthly | | 1 | $ - | $ - | 1 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kW | | 1 | $ - | $ - | 1 | $ - | $ - | |
| Tax change | per kW | -$ 0.3971 | 1 | -$ 0.40 | $ - | 1 | $ - | $ 0.40 | -100.00% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| **Sub-Total A** | | | | $ 13.05 | | | $ 24.82 | **$ 11.77** | **90.25%** |
| Deferral/Variance Account Disposition Rate Rider | per kW | -$ 4.1579 | 1 | -$ 4.16 | -$ 1.2707 | 1 | -$ 1.27 | $ 2.89 | -69.44% |
| Global Adjustment - Non RPP | per kW | -$ 0.4410 | 1 | -$ 0.44 | $ 0.5894 | 1 | $ 0.59 | $ 1.03 | -233.64% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| Low Voltage Service Charge | | | | $ - | | 0 | $ - | $ - | |
| Smart Meter Entity Charge | | | | | | 0 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 8.45** | | | **$ 24.14** | **$ 15.69** | **185.76%** |
| RTSR - Network | per kW | $ 2.2973 | 1 | $ 2.39 | $ 2.4240 | 1.0349 | $ 2.51 | $ 0.11 | 4.80% |
| RTSR - Line and Transformation Connection | per kW | $ 1.5315 | 1 | $ 1.60 | $ 1.5737 | 1.0349 | $ 1.63 | $ 0.03 | 2.06% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 12.44** | | | **$ 28.28** | **$ 15.84** | **127.36%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0052 | 156 | $ 0.81 | $ 0.0044 | 155 | $ 0.68 | -$ 0.13 | -15.96% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0011 | 156 | $ 0.17 | $ 0.0012 | 155 | $ 0.19 | $ 0.01 | 8.35% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | per kWh | $ 0.0070 | 156 | $ 1.09 | $ 0.0070 | 155 | $ 1.09 | -$ 0.01 | -0.68% |
| Energy - RPP - Tier 1 | | $ 0.0740 | 0 | $ - | $ 0.0740 | 0 | $ - | $ - | |
| Energy - RPP - Tier 2 | | $ 0.0870 | 0 | $ - | $ 0.0870 | 0 | $ - | $ - | |
| Energy - COP | | $ 0.0872 | 156 | $ 13.62 | $ 0.0872 | 155 | $ 13.53 | -$ 0.09 | -0.68% |
| | | | | | | | | | |
| | | | | | | | | | |
| **Total Bill Impact** | | | | **$ 28.39** | | | **$ 44.01** | **$ 15.62** | **55.03%** |
| HST | | 13% | | $ 3.69 | 13% | | $ 5.72 | $ 2.03 | 55.03% |
| **Total Bill** (including HST) | | | | $ 32.08 | | | $ 49.73 | $ 17.65 | 55.03% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 3.21 | | | -$ 4.97 | -$ 1.76 | 54.83% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 28.87** | | | **$ 44.76** | **$ 15.89** | **55.05%** |
| | | | | | | | | | |

| | | |
|---|---|---|
| **Loss Factor (%)** | 4.20% | 3.49% |

## Bill Impacts

**Customer Class:** **USL**

**Consumption** 0 kW  ◉ May 1 - October 31  ○ November 1 - April 30 (Select this radio button for applications filed after (
**Consumption** 150 kWh

| | Charge Unit | Current Board-Approved Rate ($) | Volume | Charge ($) | Proposed Rate ($) | Volume | Charge ($) | Impact $ Change | % Change |
|---|---|---|---|---|---|---|---|---|---|
| Monthly Service Charge | Monthly | $ 12.0600 | 1 | $ 12.06 | $ 13.1715 | 1 | $ 13.17 | $ 1.11 | 9.22% |
| Smart Meter Rate Adder | | | 1 | $ - | | 1 | $ - | $ - | |
| Stranded Meter Recovery | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| | | | 1 | $ - | | 1 | $ - | $ - | |
| Distribution Volumetric Rate | per kWh | $ 0.0072 | 150 | $ 1.08 | $ 0.0079 | 150 | $ 1.19 | $ 0.11 | 9.72% |
| Smart Meter Disposition Rider | | | 1 | $ - | $ - | 1 | $ - | $ - | |
| LRAM & SSM Rate Rider | per kWh | $ 0.0093 | 150 | $ 1.40 | $ - | 150 | $ - | -$ 1.40 | -100.00% |
| Tax change | per kWh | -$ 0.0006 | 150 | -$ 0.09 | | 150 | $ - | $ 0.09 | -100.00% |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| | | | | $ - | | 0 | $ - | $ - | |
| **Sub-Total A** | | | | $ 14.45 | | | $ 14.36 | **-$ 0.09** | **-0.61%** |
| Deferral/Variance Account Disposition Rate Rider | per kWh | -$ 0.0096 | 150 | -$ 1.44 | -$ 0.0039 | 150 | -$ 0.58 | $ 0.86 | -59.52% |
| Global Adjustment - Non RPP | | $ - | 0 | $ - | $ 0.0018 | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| | | | 0 | $ - | | 0 | $ - | $ - | |
| Low Voltage Service Charge | | | | $ - | | 0 | $ - | $ - | |
| Smart Meter Entity Charge | | | | | | 0 | $ - | $ - | |
| **Sub-Total B - Distribution (includes Sub-Total A)** | | | | **$ 13.01** | | | **$ 13.77** | **$ 0.77** | **5.91%** |
| RTSR - Network | per kWh | $ 0.0072 | 150 | $ 1.08 | $ 0.0076 | 150 | $ 1.14 | $ 0.06 | 5.56% |
| RTSR - Line and Transformation Connection | per kWh | $ 0.0048 | 150 | $ 0.72 | $ 0.0049 | 150 | $ 0.74 | $ 0.02 | 2.08% |
| **Sub-Total C - Delivery (including Sub-Total B)** | | | | **$ 14.81** | | | **$ 15.65** | **$ 0.84** | **5.70%** |
| Wholesale Market Service Charge (WMSC) | per kWh | $ 0.0052 | 150 | $ 0.78 | $ 0.0044 | 155 | $ 0.68 | -$ 0.10 | -12.43% |
| Rural and Remote Rate Protection (RRRP) | per kWh | $ 0.0011 | 150 | $ 0.17 | $ 0.0012 | 155 | $ 0.19 | $ 0.02 | 12.90% |
| Standard Supply Service Charge | Monthly | $ 0.2500 | 1 | $ 0.25 | $ 0.2500 | 1 | $ 0.25 | $ - | 0.00% |
| Debt Retirement Charge (DRC) | per kWh | $ 0.0070 | 150 | $ 1.05 | $ 0.0070 | 155 | $ 1.09 | $ 0.04 | 3.49% |
| Energy - RPP - Tier 1 | | $ 0.0750 | 0 | $ - | $ 0.0750 | 0 | $ - | $ - | |
| Energy - RPP - Tier 2 | | $ 0.0880 | 0 | $ - | $ 0.0880 | 0 | $ - | $ - | |
| Energy - COP | per kWh | $ 0.0872 | 150 | $ 13.08 | $ 0.0872 | 155 | $ 13.53 | $ 0.46 | 3.49% |
| **Total Bill on TOU (before Taxes)** | | | | **$ 30.13** | | | **$ 31.39** | **$ 1.26** | **4.19%** |
| HST | | 13% | | $ 3.92 | 13% | | $ 4.08 | $ 0.16 | 4.19% |
| **Total Bill** (including HST) | | | | $ 34.04 | | | $ 35.47 | $ 1.42 | 4.19% |
| ***Ontario Clean Energy Benefit*** [1] | | | | -$ 3.40 | | | -$ 3.55 | -$ 0.15 | 4.41% |
| **Total Bill on TOU (including OCEB)** | | | | **$ 30.64** | | | **$ 31.92** | **$ 1.27** | **4.16%** |

**Loss Factor (%)** 4.20% (current) 3.49% (proposed)

# APPENDIX B

# RTSR WORK FORM

# Rate Classes

| Rate Class | Unit | RTSR-Network | | RTSR-Connectio | |
|---|---|---|---|---|---|
| Residential | kWh | $ | 0.0080 | $ | 0.0055 |
| General Service Less Than 50 kW | kWh | $ | 0.0072 | $ | 0.0048 |
| General Service 50 to 4,999 kW | kW | $ | 2.4601 | $ | 1.6398 |
| Unmetered Scattered Load | kWh | $ | 0.0072 | $ | 0.0048 |
| Sentinel Lighting | kW | $ | 2.2973 | $ | 1.5315 |
| Street Lighting | kW | $ | 2.2708 | $ | 1.5138 |
| Embedded Distributor | kW | $ | 2.4601 | $ | 1.6398 |
| Standby Power – INTERIM APPROVAL | kW | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
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| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |
| Choose Rate Class | | | | | |

# RRR Data

| Rate Class | Unit | Non-Loss Adjusted Metered kWh | Non-Loss Adjusted Metered kW | Applicable Loss Factor | Load Factor | Loss Adjusted Billed kWh | Billed kW |
|---|---|---|---|---|---|---|---|
| Residential | kWh | 291,380,972 | | 1.0420 | | 303,618,973 | - |
| General Service Less Than 50 kW | kWh | 99,001,655 | | 1.0420 | | 103,159,725 | - |
| General Service 50 to 4,999 kW | kW | 430,250,985 | 1,156,162 | | 51.01% | 430,250,985 | 1,156,162 |
| Unmetered Scattered Load | kWh | 1,556,530 | | 1.0420 | | 1,621,904 | - |
| Sentinel Lighting | kW | 475,427 | 1,423 | | 45.78% | 475,427 | 1,423 |
| Street Lighting | kW | 7,330,830 | 22,428 | | 44.80% | 7,330,830 | 22,428 |
| Embedded Distributor | kW | | 156,840 | | 0.00% | - | 156,840 |
| Standby Power – INTERIM APPROVAL | kW | | | | | - | - |

## UTR's & Sub-Transmission

| Uniform Transmission Rates | Unit | Effective January 1, 2011 | Effective January 1, 2012 | Effective January 1, 2013 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| Network Service Rate | kW | $ 3.22 | $ 3.57 | $ 3.57 |
| Line Connection Service Rate | kW | $ 0.79 | $ 0.80 | $ 0.80 |
| Transformation Connection Service Rate | kW | $ 1.77 | $ 1.86 | $ 1.86 |

| Hydro One Sub-Transmission Rates | Unit | Effective January 1, 2011 | Effective January 1, 2012 | Effective January 1, 2013 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| Network Service Rate | kW | $ 2.65 | $ 2.65 | $ 2.65 |
| Line Connection Service Rate | kW | $ 0.64 | $ 0.64 | $ 0.64 |
| Transformation Connection Service Rate | kW | $ 1.50 | $ 1.50 | $ 1.50 |
| Both Line and Transformation Connection Service Rate | kW | $ 2.14 | $ 2.14 | $ 2.14 |

| Hydro One Sub-Transmission Rate Rider 6A | Unit | Effective January 1, 2011 | Effective January 1, 2012 | Effective January 1, 2013 |
|---|---|---|---|---|
| **Rate Description** | | **Rate** | **Rate** | **Rate** |
| RSVA Transmission network – 4714 – which affects 1584 | kW | $ 0.0470 | $ - | $ - |
| RSVA Transmission connection – 4716 – which affects 158 | kW | -$ 0.0250 | $ - | $ - |
| RSVA LV – 4750 – which affects 1550 | kW | $ 0.0580 | $ - | $ - |
| RARA 1 – 2252 – which affects 1590 | kW | -$ 0.0750 | $ - | $ - |
| Hydro One Sub-Transmission Rate Rider 6A | kW | $ 0.0050 | $ - | $ - |

# Historical Wholesale

| IESO | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 158,056 | $3.22 | $ 508,940 | 160,986 | $0.79 | $ 127,108 | 135,661 | $1.77 | $ 240,120 | $ 367,228 |
| February | 154,508 | $3.22 | $ 497,516 | 161,229 | $0.79 | $ 127,371 | 105,510 | $1.77 | $ 186,753 | $ 314,124 |
| March | 145,699 | $3.22 | $ 469,009 | 147,886 | $0.79 | $ 116,830 | 96,528 | $1.77 | $ 170,855 | $ 287,685 |
| April | 131,837 | $3.22 | $ 424,515 | 140,039 | $0.79 | $ 110,631 | 93,430 | $1.77 | $ 165,371 | $ 276,002 |
| May | 170,516 | $3.22 | $ 549,062 | 177,713 | $0.79 | $ 140,393 | 127,187 | $1.77 | $ 225,121 | $ 365,514 |
| June | 183,492 | $3.22 | $ 590,844 | 185,036 | $0.79 | $ 146,178 | 142,175 | $1.77 | $ 251,650 | $ 397,828 |
| July | 202,480 | $3.22 | $ 651,986 | 203,121 | $0.79 | $ 160,466 | 179,370 | $1.77 | $ 317,485 | $ 477,950 |
| August | 173,113 | $3.22 | $ 557,424 | 176,351 | $0.79 | $ 139,317 | 155,086 | $1.77 | $ 274,502 | $ 413,820 |
| September | 174,800 | $3.22 | $ 562,856 | 177,698 | $0.79 | $ 140,381 | 156,209 | $1.77 | $ 276,490 | $ 416,871 |
| October | 131,873 | $3.22 | $ 424,631 | 132,554 | $0.79 | $ 104,718 | 116,370 | $1.77 | $ 205,975 | $ 310,693 |
| November | 141,505 | $3.22 | $ 455,646 | 146,561 | $0.79 | $ 115,783 | 129,940 | $1.77 | $ 229,994 | $ 345,777 |
| December | 143,725 | $3.22 | $ 462,795 | 148,916 | $0.79 | $ 117,644 | 130,210 | $1.77 | $ 230,472 | $ 348,115 |
| **Total** | 1,911,604 | $ 3.22 | $ 6,155,223 | 1,958,090 | $ 0.79 | $ 1,546,820 | 1,567,676 | $ 1.77 | $ 2,774,787 | $ 4,321,607 |

| Hydro One | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| February | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| March | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| April | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| May | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| June | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| July | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| August | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| September | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| October | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| November | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| December | | $0.00 | | | $0.00 | | | $0.00 | | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Total | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 158,056 | $3.22 | $ 508,940 | 160,986 | $0.79 | $ 127,108 | 135,661 | $1.77 | $ 240,120 | $ 367,228 |
| February | 154,508 | $3.22 | $ 497,516 | 161,229 | $0.79 | $ 127,371 | 105,510 | $1.77 | $ 186,753 | $ 314,124 |
| March | 145,699 | $3.22 | $ 469,009 | 147,886 | $0.79 | $ 116,830 | 96,528 | $1.77 | $ 170,855 | $ 287,685 |
| April | 131,837 | $3.22 | $ 424,515 | 140,039 | $0.79 | $ 110,631 | 93,430 | $1.77 | $ 165,371 | $ 276,002 |
| May | 170,516 | $3.22 | $ 549,062 | 177,713 | $0.79 | $ 140,393 | 127,187 | $1.77 | $ 225,121 | $ 365,514 |
| June | 183,492 | $3.22 | $ 590,844 | 185,036 | $0.79 | $ 146,178 | 142,175 | $1.77 | $ 251,650 | $ 397,828 |
| July | 202,480 | $3.22 | $ 651,986 | 203,121 | $0.79 | $ 160,466 | 179,370 | $1.77 | $ 317,485 | $ 477,950 |
| August | 173,113 | $3.22 | $ 557,424 | 176,351 | $0.79 | $ 139,317 | 155,086 | $1.77 | $ 274,502 | $ 413,820 |
| September | 174,800 | $3.22 | $ 562,856 | 177,698 | $0.79 | $ 140,381 | 156,209 | $1.77 | $ 276,490 | $ 416,871 |
| October | 131,873 | $3.22 | $ 424,631 | 132,554 | $0.79 | $ 104,718 | 116,370 | $1.77 | $ 205,975 | $ 310,693 |
| November | 141,505 | $3.22 | $ 455,646 | 146,561 | $0.79 | $ 115,783 | 129,940 | $1.77 | $ 229,994 | $ 345,777 |
| December | 143,725 | $3.22 | $ 462,795 | 148,916 | $0.79 | $ 117,644 | 130,210 | $1.77 | $ 230,472 | $ 348,115 |
| **Total** | 1,911,604 | $ 3.22 | $ 6,155,223 | 1,958,090 | $ 0.79 | $ 1,546,820 | 1,567,676 | $ 1.77 | $ 2,774,787 | $ 4,321,607 |

# Current Wholesale

| IESO | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 158,056 | $ 3.5700 | $ 564,260 | 160,986 | $ 0.8000 | $ 128,789 | 135,661 | $ 1.8600 | $ 252,329 | $ 381,118 |
| February | 154,508 | $ 3.5700 | $ 551,594 | 161,229 | $ 0.8000 | $ 128,983 | 105,510 | $ 1.8600 | $ 196,249 | $ 325,232 |
| March | 145,699 | $ 3.5700 | $ 520,145 | 147,886 | $ 0.8000 | $ 118,309 | 96,528 | $ 1.8600 | $ 179,542 | $ 297,851 |
| April | 131,837 | $ 3.5700 | $ 470,658 | 140,039 | $ 0.8000 | $ 112,031 | 93,430 | $ 1.8600 | $ 173,780 | $ 285,811 |
| May | 170,516 | $ 3.5700 | $ 608,742 | 177,713 | $ 0.8000 | $ 142,170 | 127,187 | $ 1.8600 | $ 236,568 | $ 378,738 |
| June | 183,492 | $ 3.5700 | $ 655,066 | 185,036 | $ 0.8000 | $ 148,029 | 142,175 | $ 1.8600 | $ 264,446 | $ 412,474 |
| July | 202,480 | $ 3.5700 | $ 722,854 | 203,121 | $ 0.8000 | $ 162,497 | 179,370 | $ 1.8600 | $ 333,628 | $ 496,125 |
| August | 173,113 | $ 3.5700 | $ 618,013 | 176,351 | $ 0.8000 | $ 141,081 | 155,086 | $ 1.8600 | $ 288,460 | $ 429,541 |
| September | 174,800 | $ 3.5700 | $ 624,036 | 177,698 | $ 0.8000 | $ 142,158 | 156,209 | $ 1.8600 | $ 290,549 | $ 432,707 |
| October | 131,873 | $ 3.5700 | $ 470,787 | 132,554 | $ 0.8000 | $ 106,043 | 116,370 | $ 1.8600 | $ 216,448 | $ 322,491 |
| November | 141,505 | $ 3.5700 | $ 505,173 | 146,561 | $ 0.8000 | $ 117,249 | 129,940 | $ 1.8600 | $ 241,688 | $ 358,937 |
| December | 143,725 | $ 3.5700 | $ 513,098 | 148,916 | $ 0.8000 | $ 119,133 | 130,210 | $ 1.8600 | $ 242,191 | $ 361,323 |
| **Total** | 1,911,604 | $ 3.57 | $ 6,824,426 | 1,958,090 | $ 0.80 | $ 1,566,472 | 1,567,676 | $ 1.86 | $ 2,915,877 | $ 4,482,349 |

| Hydro One | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| February | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| March | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| April | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| May | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| June | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| July | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| August | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| September | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| October | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| November | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| December | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Total | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 158,056 | $ 3.57 | $ 564,260 | 160,986 | $ 0.80 | $ 128,789 | 135,661 | $ 1.86 | $ 252,329 | $ 381,118 |
| February | 154,508 | $ 3.57 | $ 551,594 | 161,229 | $ 0.80 | $ 128,983 | 105,510 | $ 1.86 | $ 196,249 | $ 325,232 |
| March | 145,699 | $ 3.57 | $ 520,145 | 147,886 | $ 0.80 | $ 118,309 | 96,528 | $ 1.86 | $ 179,542 | $ 297,851 |
| April | 131,837 | $ 3.57 | $ 470,658 | 140,039 | $ 0.80 | $ 112,031 | 93,430 | $ 1.86 | $ 173,780 | $ 285,811 |
| May | 170,516 | $ 3.57 | $ 608,742 | 177,713 | $ 0.80 | $ 142,170 | 127,187 | $ 1.86 | $ 236,568 | $ 378,738 |
| June | 183,492 | $ 3.57 | $ 655,066 | 185,036 | $ 0.80 | $ 148,029 | 142,175 | $ 1.86 | $ 264,446 | $ 412,474 |
| July | 202,480 | $ 3.57 | $ 722,854 | 203,121 | $ 0.80 | $ 162,497 | 179,370 | $ 1.86 | $ 333,628 | $ 496,125 |
| August | 173,113 | $ 3.57 | $ 618,013 | 176,351 | $ 0.80 | $ 141,081 | 155,086 | $ 1.86 | $ 288,460 | $ 429,541 |
| September | 174,800 | $ 3.57 | $ 624,036 | 177,698 | $ 0.80 | $ 142,158 | 156,209 | $ 1.86 | $ 290,549 | $ 432,707 |
| October | 131,873 | $ 3.57 | $ 470,787 | 132,554 | $ 0.80 | $ 106,043 | 116,370 | $ 1.86 | $ 216,448 | $ 322,491 |
| November | 141,505 | $ 3.57 | $ 505,173 | 146,561 | $ 0.80 | $ 117,249 | 129,940 | $ 1.86 | $ 241,688 | $ 358,937 |
| December | 143,725 | $ 3.57 | $ 513,098 | 148,916 | $ 0.80 | $ 119,133 | 130,210 | $ 1.86 | $ 242,191 | $ 361,323 |
| **Total** | 1,911,604 | $ 3.57 | $ 6,824,426 | 1,958,090 | $ 0.80 | $ 1,566,472 | 1,567,676 | $ 1.86 | $ 2,915,877 | $ 4,482,349 |

# Forecast Wholesale

| IESO | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 158,056 | $ 3.5700 | $ 564,260 | 160,986 | $ 0.8000 | $ 128,789 | 135,661 | $ 1.8600 | $ 252,329 | $ 381,118 |
| February | 154,508 | $ 3.5700 | $ 551,594 | 161,229 | $ 0.8000 | $ 128,983 | 105,510 | $ 1.8600 | $ 196,249 | $ 325,232 |
| March | 145,699 | $ 3.5700 | $ 520,145 | 147,886 | $ 0.8000 | $ 118,309 | 96,528 | $ 1.8600 | $ 179,542 | $ 297,851 |
| April | 131,837 | $ 3.5700 | $ 470,658 | 140,039 | $ 0.8000 | $ 112,031 | 93,430 | $ 1.8600 | $ 173,780 | $ 285,811 |
| May | 170,516 | $ 3.5700 | $ 608,742 | 177,713 | $ 0.8000 | $ 142,170 | 127,187 | $ 1.8600 | $ 236,568 | $ 378,738 |
| June | 183,492 | $ 3.5700 | $ 655,066 | 185,036 | $ 0.8000 | $ 148,029 | 142,175 | $ 1.8600 | $ 264,446 | $ 412,474 |
| July | 202,480 | $ 3.5700 | $ 722,854 | 203,121 | $ 0.8000 | $ 162,497 | 179,370 | $ 1.8600 | $ 333,628 | $ 496,125 |
| August | 173,113 | $ 3.5700 | $ 618,013 | 176,351 | $ 0.8000 | $ 141,081 | 155,086 | $ 1.8600 | $ 288,460 | $ 429,541 |
| September | 174,800 | $ 3.5700 | $ 624,036 | 177,698 | $ 0.8000 | $ 142,158 | 156,209 | $ 1.8600 | $ 290,549 | $ 432,707 |
| October | 131,873 | $ 3.5700 | $ 470,787 | 132,554 | $ 0.8000 | $ 106,043 | 116,370 | $ 1.8600 | $ 216,448 | $ 322,491 |
| November | 141,505 | $ 3.5700 | $ 505,173 | 146,561 | $ 0.8000 | $ 117,249 | 129,940 | $ 1.8600 | $ 241,688 | $ 358,937 |
| December | 143,725 | $ 3.5700 | $ 513,098 | 148,916 | $ 0.8000 | $ 119,133 | 130,210 | $ 1.8600 | $ 242,191 | $ 361,323 |
| **Total** | 1,911,604 | $ 3.57 | $ 6,824,426 | 1,958,090 | $ 0.80 | $ 1,566,472 | 1,567,676 | $ 1.86 | $ 2,915,877 | $ 4,482,349 |

| Hydro One | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| February | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| March | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| April | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| May | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| June | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| July | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| August | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| September | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| October | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| November | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| December | - | $ 2.6500 | $ - | - | $ 0.6400 | $ - | - | $ 1.5000 | $ - | $ - |
| **Total** | - | $ - | $ - | - | $ - | $ - | - | $ - | $ - | $ - |

| Total | Network | | | Line Connection | | | Transformation Connection | | | Total Line |
|---|---|---|---|---|---|---|---|---|---|---|
| Month | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Units Billed | Rate | Amount | Amount |
| January | 158,056 | $ 3.57 | $ 564,260 | 160,986 | $ 0.80 | $ 128,789 | 135,661 | $ 1.86 | $ 252,329 | $ 381,118 |
| February | 154,508 | $ 3.57 | $ 551,594 | 161,229 | $ 0.80 | $ 128,983 | 105,510 | $ 1.86 | $ 196,249 | $ 325,232 |
| March | 145,699 | $ 3.57 | $ 520,145 | 147,886 | $ 0.80 | $ 118,309 | 96,528 | $ 1.86 | $ 179,542 | $ 297,851 |
| April | 131,837 | $ 3.57 | $ 470,658 | 140,039 | $ 0.80 | $ 112,031 | 93,430 | $ 1.86 | $ 173,780 | $ 285,811 |
| May | 170,516 | $ 3.57 | $ 608,742 | 177,713 | $ 0.80 | $ 142,170 | 127,187 | $ 1.86 | $ 236,568 | $ 378,738 |
| June | 183,492 | $ 3.57 | $ 655,066 | 185,036 | $ 0.80 | $ 148,029 | 142,175 | $ 1.86 | $ 264,446 | $ 412,474 |
| July | 202,480 | $ 3.57 | $ 722,854 | 203,121 | $ 0.80 | $ 162,497 | 179,370 | $ 1.86 | $ 333,628 | $ 496,125 |
| August | 173,113 | $ 3.57 | $ 618,013 | 176,351 | $ 0.80 | $ 141,081 | 155,086 | $ 1.86 | $ 288,460 | $ 429,541 |
| September | 174,800 | $ 3.57 | $ 624,036 | 177,698 | $ 0.80 | $ 142,158 | 156,209 | $ 1.86 | $ 290,549 | $ 432,707 |
| October | 131,873 | $ 3.57 | $ 470,787 | 132,554 | $ 0.80 | $ 106,043 | 116,370 | $ 1.86 | $ 216,448 | $ 322,491 |
| November | 141,505 | $ 3.57 | $ 505,173 | 146,561 | $ 0.80 | $ 117,249 | 129,940 | $ 1.86 | $ 241,688 | $ 358,937 |
| December | 143,725 | $ 3.57 | $ 513,098 | 148,916 | $ 0.80 | $ 119,133 | 130,210 | $ 1.86 | $ 242,191 | $ 361,323 |
| **Total** | 1,911,604 | $ 3.57 | $ 6,824,426 | 1,958,090 | $ 0.80 | $ 1,566,472 | 1,567,676 | $ 1.86 | $ 2,915,877 | $ 4,482,349 |

## ADJ Network to Current WS

| Unit | Current RTSR-Network | | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | | Billed Amount % | Current Wholesale Billing | | Proposed RTSR Network | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| kWh | $ | 0.0080 | 303,618,973 | - | $ | 2,428,952 | 37.6% | $ | 2,562,923 | $ | 0.0084 |
| kWh | $ | 0.0072 | 103,159,725 | - | $ | 742,750 | 11.5% | $ | 783,717 | $ | 0.0076 |
| kW | $ | 2.4601 | 430,250,985 | 1,156,162 | $ | 2,844,274 | 44.0% | $ | 3,001,152 | $ | 2.5958 |
| kWh | $ | 0.0072 | 1,621,904 | - | $ | 11,678 | 0.2% | $ | 12,322 | $ | 0.0076 |
| kW | $ | 2.2973 | 475,427 | 1,423 | $ | 3,270 | 0.1% | $ | 3,450 | $ | 2.4240 |
| kW | $ | 2.2708 | 7,330,830 | 22,428 | $ | 50,930 | 0.8% | $ | 53,739 | $ | 2.3960 |
| kW | $ | 2.4601 | - | 156,840 | $ | 385,842 | 6.0% | $ | 407,124 | $ | 2.5958 |
| kW | $ | - | - | - | $ | - | 0.0% | $ | - | $ | - |
| | | | | | $ | 6,467,695 | | | | | |

# ADJ Conn. to Current WS

| Unit | Current RTSR-Connection | | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | | Billed Amount % | Current Wholesale Billing | | Proposed RTSR Connection | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| kWh | $ | 0.0055 | 303,618,973 | - | $ | 1,669,904 | 38.3% | $ | 1,715,959 | $ | 0.0057 |
| kWh | $ | 0.0048 | 103,159,725 | - | $ | 495,167 | 11.4% | $ | 508,823 | $ | 0.0049 |
| kW | $ | 1.6398 | 430,250,985 | 1,156,162 | $ | 1,895,874 | 43.5% | $ | 1,948,161 | $ | 1.6850 |
| kWh | $ | 0.0048 | 1,621,904 | - | $ | 7,785 | 0.2% | $ | 8,000 | $ | 0.0049 |
| kW | $ | 1.5315 | 475,427 | 1,423 | $ | 2,180 | 0.0% | $ | 2,240 | $ | 1.5737 |
| kW | $ | 1.5138 | 7,330,830 | 22,428 | $ | 33,952 | 0.8% | $ | 34,888 | $ | 1.5555 |
| kW | $ | 1.6398 | - | 156,840 | $ | 257,186 | 5.9% | $ | 264,279 | $ | 1.6850 |
| kW | $ | - | - | - | $ | - | 0.0% | $ | - | $ | - |
| | | | | | $ | 4,362,048 | | | | | |

# ADJ Network to Forecast WS

| Rate Class | Unit | Adjusted RTSR-Network | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | Billed Amount % | Forecast Wholesale Billing | Proposed RTSR Network |
|---|---|---|---|---|---|---|---|---|
| Residential | kWh | $ 0.0084 | 303,618,973 | - | $ 2,562,923 | 37.6% | $ 2,562,923 | $ 0.0084 |
| General Service Less Than 50 kW | kWh | $ 0.0076 | 103,159,725 | - | $ 783,717 | 11.5% | $ 783,717 | $ 0.0076 |
| General Service 50 to 4,999 kW | kW | $ 2.5958 | 430,250,985 | 1,156,162 | $ 3,001,152 | 44.0% | $ 3,001,152 | $ 2.5958 |
| Unmetered Scattered Load | kWh | $ 0.0076 | 1,621,904 | - | $ 12,322 | 0.2% | $ 12,322 | $ 0.0076 |
| Sentinel Lighting | kW | $ 2.4240 | 475,427 | 1,423 | $ 3,450 | 0.1% | $ 3,450 | $ 2.4240 |
| Street Lighting | kW | $ 2.3960 | 7,330,830 | 22,428 | $ 53,739 | 0.8% | $ 53,739 | $ 2.3960 |
| Embedded Distributor | kW | $ 2.5958 | - | 156,840 | $ 407,124 | 6.0% | $ 407,124 | $ 2.5958 |
| Standby Power – INTERIM APPROVAL | kW | $ - | - | - | $ - | 0.0% | $ - | $ - |
| | | | | | $ 6,824,426 | | | |

# ADJ Conn. to Forecast WS

| Unit | Adjusted RTSR-Connection | Loss Adjusted Billed kWh | Loss Adjusted Billed kW | Billed Amount | Billed Amount % | Forecast Wholesale Billing | Proposed RTSR Connection |
|---|---|---|---|---|---|---|---|
| kWh | $ 0.0057 | 303,618,973 | - | $ 1,715,959 | 38.3% | $ 1,715,959 | $ 0.0057 |
| kWh | $ 0.0049 | 103,159,725 | - | $ 508,823 | 11.4% | $ 508,823 | $ 0.0049 |
| kW | $ 1.6850 | 430,250,985 | 1,156,162 | $ 1,948,161 | 43.5% | $ 1,948,161 | $ 1.6850 |
| kWh | $ 0.0049 | 1,621,904 | - | $ 8,000 | 0.2% | $ 8,000 | $ 0.0049 |
| kW | $ 1.5737 | 475,427 | 1,423 | $ 2,240 | 0.0% | $ 2,240 | $ 1.5737 |
| kW | $ 1.5555 | 7,330,830 | 22,428 | $ 34,888 | 0.8% | $ 34,888 | $ 1.5555 |
| kW | $ 1.6850 | - | 156,840 | $ 264,279 | 5.9% | $ 264,279 | $ 1.6850 |
| kW | $ - | - | - | $ - | 0.0% | $ - | $ - |
| | | | | $ 4,482,349 | | | |

**Final 2013 RTS Rates**

| Rate Class | Unit | Proposed RTSR Network | Proposed RTSR Connection |
|---|---|---|---|
| Residential | kWh | $ 0.0084 | $ 0.0057 |
| General Service Less Than 50 kW | kWh | $ 0.0076 | $ 0.0049 |
| General Service 50 to 4,999 kW | kW | $ 2.5958 | $ 1.6850 |
| Unmetered Scattered Load | kWh | $ 0.0076 | $ 0.0049 |
| Sentinel Lighting | kW | $ 2.4240 | $ 1.5737 |
| Street Lighting | kW | $ 2.3960 | $ 1.5555 |
| Embedded Distributor | kW | $ 2.5958 | $ 1.6850 |
| Standby Power – INTERIM APPROVAL | kW | $ - | $ - |

# DEFERRAL AND VARIANCE ACCOUNTS:

## OVERVIEW

The information contained in this Exhibit includes the status and description of BPI's deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

## PREVIOUS DEFERRAL / VARIANCE ACCOUNT DISPOSITION

## 2012 IRM

On April 19, 2012, in its Decision and Order in BPI's 2012 IRM application (EB-2011-0147) approved a one year disposition of Group 1 account balances as of December 31st 2010, effective May 1, 2012. The account balances were transferred to account 1595 and rates for disposition were approved until April 30, 2013. The table below identifies the principal and interest amounts for Group 1 accounts that were approved for disposition.

**TABLE 9.1: Disposition of Deferral and Variance Account Balances – 2012 IRM**

| Account Name | Account Number | Principal Balance | Interest Balance | Total Claim |
|---|---|---|---|---|
| LV Variance Account | 1550 | - | - | - |
| RSVA - Wholesale Market Service Charge | 1580 | -$1,063,709 | -$24,751 | -$1,088,460 |
| RSVA - Retail Transmission Network Charge | 1584 | -$1,089,431 | -$24,222 | -$1,113,653 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$1,121,985 | -$24,485 | -$1,146,470 |
| RSVA - Power (excluding Global Adjustment) | 1588 | $337,568 | -$11,932 | $325,636 |
| RSVA - Power - Sub-Account - Global Adjustment | 1588 | -$792,903 | -$24,026 | -$816,929 |
| Disposition and Recovery of Regulatory Balances (2008) | 1595 | - | - | - |
| Disposition and Recovery of Regulatory Balances (2009) | 1595 | - | - | - |
| **Group 1 Total** | | | | **-$3,839,876** |

In that Decision and Order, the Board approved the disposition of the debit balance in Account 1521 – Special Purpose Charge over a one-year period and directed BPI to close that account effective May 1, 2012. The balance of Account 1521 was transferred to Account 1595 and rates for disposition were approved to April 30, 2013.

As well, the Board approved the disposition of the credit balance in the amount of $2,021,450 in Account 1562 – Deferred Payment in Lieu of Taxes, over a one-year period. The balance of Account 1562 was transferred to Account 1595 and rates for disposition were approved to April 30, 2013.

## STATUS OF DEFERRAL AND VARIANCE ACCOUNTS:

This Schedule contains the status of Deferral and Variance Accounts ("DVAs") currently used by BPI. The balances as at December 31, 2012 and where applicable, interest forecasted to April 30, 2013 and the proposed recovery amounts are summarized in Table 9.2 following the descriptions of each account:

## GROUP 1 ACCOUNTS

### 1550 LV Variance Account

As BPI does not have approved low voltage rates, this account is not in use by BPI.

### 1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the Board-approved Wholesale Market Service Rate. BPI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a credit of ($2,452,847).

### 1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the Board approved Retail Transmission Rate for network services. BPI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a debit of $178,318.

**1586 Retail Settlement Variance Account - Retail Transmission Connection Charges**

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the Board-approved Retail Transmission Rate for connection services. BPI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a credit of ($9,093).

**1588 Retail Settlement Variance Account – Power (excluding Global Adjustment)**

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to BPI using the settlement invoice from the Independent Electricity System Operator (IESO). BPI uses the accrual method. The variance between Board-approved and actual line losses is reflected in Account 1588 for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a credit of ($1,800,496).

**1589 Retail Settlement Variance Account - Power, Sub-account Global Adjustment**

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to BPI using the settlement invoice from the IESO. BPI uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013 for account 1588 sub account Global Adjustment through a separate non-RPP rate rider. The requested amount is a debit of $809,913.

**1595 Disposition and Recovery/Refund of Regulatory Balances**

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts approved by the Board in BPI's 2010 IRM (EB-2009-0214) and 2011 IRM rates cases (EB-2010-0066). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

In accordance with the Board's Decision and Order in BPI's 2010 IRM rate application (EB-2009-0214), the December 31, 2008 balances and projected interest to April 30, 2010 totaling ($7,595,490) were transferred to account 1595 for disposition over a two-year period. As well, in accordance with the Board's Decision and Order in BPI's 2011 IRM rate application (EB-2010-0066), the December 31, 2009 balances and projected interest to April 30, 2011 totaling ($1,192,282).were also transferred to account 1595 for disposition over a one-year period.

BPI is requesting disposition of the residual balances from Group 1 Deferral and Variance Accounts dispositions from 2010 of ($949,509.51) and from 2011 of $139,715.42 for a total residual balance of ($808,693). There are residual balances in Account 1595 primarily because the rate riders for those years were based on BPI's Board Approved load forecast which differed from BPI's actual loads.

BPI notes that the rate riders approved in the Board's Decision and Order in BPI's 2012 IRM rate application were still in effect at the end of 2012 and BPI will request disposition of the 2012 rate rider balances in a future rate application.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance, excluding the balances resulting from the 2012 IRM, plus the forecasted interest through April 30, 2013. The requested amount is a credit of ($808,693).

## GROUP 2 ACCOUNTS

### 1508 Other Regulatory Assets - Sub-account Board Cost Assessments

This account includes amounts for interest remaining on previous Board Cost Assessment balances that BPI disposed of during the 2008 rate application. In that rate application, BPI had estimated the interest until May 1, 2008 but new rates did not come into effect until September 1, 2008. The balance in the account comprises the interest that was incurred between May 1 and Sept 1, 2008. The Board prescribed interest rates used to calculate the carrying charges and the interest is recorded in a sub-account.

BPI is requesting disposition of the December 31, 2012 audited balance. The requested amount is a debit of $946.

### 1508 Other Regulatory Assets - Sub-account Pension Contributions

This account is not currently in use by BPI.

### 1508 Other Regulatory Assets – Sub-account IFRS Transition Costs

This account includes amounts paid for one-time incremental costs for the transition to International Financial Reporting Standards (IFRS). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

BPI has established account 1508 – sub account IFRS Transition Costs in accordance with the Board Requirements. The balance as of December 31, 2012 is $224,221.

However, as BPI has not completed the transition to IFRS, BPI is not requesting disposition of this account until the transition to IFRS is complete.

**1508 Other Regulatory Assets – Sub-account Incremental Capital Charges**

This account is not currently in use by BPI.

**1508 Other Regulatory Assets – Sub-account Financial Assistance Payment and Recovery Carrying Charges – Ontario Clean Energy Benefit**

This account is not in use by BPI.

**1508 Other Regulatory Assets – Financial Assistance Payment and Recovery Carrying Charges**

This account is not in use by BPI.

**1508 Other Regulatory Assets – Sub-account – Other**

In BPI's 2008 rate application (EB-2007-0698), BPI proposed that its embedded distributor be billed using the rates approved for the General Service > 50 kW class and such billing treatment was approved by the Board. Subsequently, the Board convened a proceeding, EB-2009-0063, into the billing treatment of BPI's embedded distributor with the result that BPI was directed to establish an embedded distributor rate class. In its Decision and Order dated August 10, 2010, the Board stated:

> ***Board Findings – The Distribution Rate***
>
> *We agree with Board staff that a separate rate should be set for Brant County. We also agree that rate should be set based on the principles set out above by Board staff. We are also of the view that further delay is no longer warranted. This issue first arose in Brantford's Application for 2008 rates. It remains unresolved and no payments are being made by Brant County.*
>
> *The Board directs Brantford to design a rate in compliance with principles set out by Board staff and to file that rate within 10 days of receipt of this Decision. Brant County will have an opportunity to comment on the proposed rate within 5 days of receipt. The Board expects to be in a position to issue a written decision following these submissions.*

> *If the new rate is less than the existing rate there may be an under-recovery by Brantford. That is, the utility would not be able to achieve its revenue requirement.*
>
> *Accordingly, the difference between the existing approved GS > 50 kW rate and the new Brant County rate times the Brant County volumes for the relevant period should be tracked in a variance account for recovery at Brantford's next rebasing. The Board notes that Brant County has no objection. (Pages 14 and 15).*

Noting that BPI has under-recovered its revenue requirement for the period of September 2008 to December 31, 2012, the balance in this account comprises the difference between the revenues that would have been collected from the embedded distributor using the approved GS > 50 kW rate and the subsequent embedded distributor rate times the BCPI volumes for that period.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a debit of $670,257.

**1518 Retail Settlement Variance Account – Retail**

This account is used to recover the net differences between the revenues recovered from Retailer Service Agreements and Billing options and the cost of managing the retailer contracts. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a debit of $28,802.

**1525 Miscellaneous Deferred Debits**

This account includes the amount of interest remaining from expenses related to the Ontario Price Credit rebate cheques issued in 2002 and 2003. In BPI's 2008 Cost of

Service rate application, BPI had estimated the interest until May 1, 2008 but new rates did not come into effect until September 1, 2008. The balance in the account comprises the interest that was incurred between May 1 and Sept 1, 2008. The Board prescribed interest rates used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance. The requested amount is a debit of $82.

**1531 Renewable Generation Connection Capital Deferral Account**

This account is not in use by BPI.

**1532 Renewable Connection OM&A Deferral Account**

This account includes the amounts paid for incremental operating, maintenance, amortization and administrative expenses directly related to "renewable enabling improvements" as defined in Board Guideline G-2009-0087 Deemed Conditions of License: Distribution System Planning, June 16, 2009. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

BPI has established the 1532 Renewable Connection OM&A Deferral Account in accordance with the above-mentioned Guideline G-2009-0087, to track costs associated with renewable connection OM&A.

An amount of $8,793 in Account 1532 represents an upgrade to BPI's CIS system to enable BPI to perform billing for RESOP customers. BPI recognizes that for up-front OM&A costs in this account, a pooling mechanism should be applied. Due to the low dollar value of this expenditure which is below the materiality threshold, BPI has not applied the direct benefit calculation, but instead included 100% of the costs in account 1532.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a debit of $8,793.

**1534 Smart Grid Capital Deferral Account**

BPI is not currently tracking costs to this account.

**1535 Smart Grid OM&A Deferral Account**

BPI is not currently tracking costs to this account.

**1548 Retail Settlement Variance Account – Service Transaction Request**

This account is used to recover the net differences between the revenues recovered from Service Transaction Requests and the incremental costs of providing these services. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a debit of $323,629.

**1555 Smart Meter Capital and Recovery Offset Variance**

This account records the net of the amounts paid for direct capital costs related to the smart meter program and the amounts charged to customers using the Board approved smart meter rate adder. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

The disposition of the balances in this account is discussed further in Tab 3 of this Exhibit.

**1556 Smart Meter OM&A Variance**

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. BPI is following the Smart Meter Funding and Cost Recovery Guideline dated October 22, 2008 (G-2008-0002) and is requesting recovery of the December 31, 2012 audited balance for account 1556 – Smart Meter OM&A Variance through a smart meter rate recovery rider.

The disposition of the balances in this account is discussed further in Tab 3 of this Exhibit.

**1562 Deferred Payments in Lieu of Taxes; Contra Account Deferred Payments in Lieu of Taxes**

As noted above, the Board approved the disposition of the credit balance in the amount of $2,021,450 in Account 1562 – Deferred Payment in Lieu of Taxes, over a one-year period in BPI's 2012 IRM application. The balance of Account 1562 was transferred to Account 1595 and rates for disposition were approved to April 30, 2013.

BPI is not requesting any further dispositions of this account.

**1568 LRAM Variance Account**

This account includes the lost revenue adjustment mechanism ("LRAM") variances in relation to the conservation and demand management ("CDM") programs or activities undertaken by a distributor in accordance with Board prescribed requirements (e.g. licence, codes and guidelines). Since 2011, BPI has delivered a full slate of CDM offered by the Ontario Power Authority ("OPA").

BPI has booked the following estimated lost revenue amounts as a result of those CDM programs to this account:

| | |
|---|---|
| 2011 Estimated Lost Revenue | $33,041.49 |
| 2011 Estimated Persistence into 2012 | $33,041.49 |
| 2012 Estimated Lost Revenue | $29,446.47 |
| **Total** | **$95,502.75** |

BPI notes that the amounts booked to this account for 2011 are estimated amounts that require further due diligence by BPI. For 2012 programs, the amounts recorded in the LRAM variance account are based on estimates as the final program results from the OPA have not yet been released. Because the amounts in this account are estimates, BPI advises that it is not seeking disposition on the amounts in this account at this time.

**1572 Extraordinary Events Costs**

This account records the costs of extraordinary events, which are not recovered in current rates. As at December 31, 2012 the balance in this account was zero.

**1575 IFRS-CGAAP Transitional PP&E**

This account is used to record differences arising as a result of accounting policy changes caused by the transition from previous Canadian GAAP to modified IFRS. As BPI has not transitioned to IFRS and has filed this application on the basis of M-CGAAP, the balance in this account is $0.00.

**1582 Retail Settlement Variance Account – One-time**

This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the Board approved rate. BPI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

In 2005, BPI reallocated IMO (IESO) one-time charges as designated on the IESO invoice of $264,944.63 (principal) from Account 1580 to Account 1582. Although BPI proposed disposition of Account 1582 in its 2008 cost-of-service rate application, all RSVA accounts (1580-1588) were removed from disposition as the Board was developing the new disposition rules that started at BPI's 2010 IRM. In subsequent IRM rate applications, Account 1582 was not included in the Group 1 dispositions with the result that this application is the first opportunity for BPI to request disposition of this account.

The reallocated One-Time Charges before carrying charges are detailed as follows:

| | | 2002 | 2003 | 2004 | 2005 | Total |
|---|---|---|---|---|---|---|
| | | | | | | |
| 0163 | Market Suspension Additional Comp. | - | 71,059.11 | 16,888.28 | 2.84 | 87,950.23 |
| 0164 | Outage Cancellation/Deferral Debit | 6.18 | - | - | 37.56 | 43.74 |
| 0167 | Emergency Energy and EDRP Debit | 32,964.91 | 1,983.56 | 9,847.87 | 9,926.63 | 54,722.97 |
| 0169 | Station Service Reimbursement Debit | 21,528.13 | 25,328.23 | 31,639.86 | 43,731.47 | 122,227.69 |
| | | 54,499.22 | 98,370.90 | 58,376.01 | 53,698.50 | 264,944.63 |

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

For 2013, BPI is requesting disposition of the December 31, 2012 audited balance plus the forecasted interest through April 30, 2013. The requested amount is a debit of $353,252.

**1592 PILs and Tax Variance for 2008 and Subsequent Year – Sub-account HST/OVAT Input Tax Credits**

Effective July 1, 2010, distributors were directed to record the incremental ITC received on distribution revenue requirement items that were previously subject to PST and became subject to HST. Tracking of these amounts would continue in this deferral account until the effective date of distributors' next cost of service rate order. Fifty per cent of the confirmed balance in this account shall be returnable to the rate payers. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

The monthly procedures used by BPI to calculate the HST variance account are described below.

Six categories go into the HST variance account on a monthly basis:

1) ITCs tracked directly from accounts payable invoices;
    a) Since July 1, 2010, BPI set up a tax code within the Financial Information System to differentiate expenditures that had PST and GST prior to the implementation of HST. This code allows the 8% PST portion of the HST to be tracked to a distinct ITC account (HST SAVE) and the 5% GST portion of the HST to be tracked to the regular ITC account.
    b) The HST SAVE account is reviewed monthly to subtotal by inventory purchases and normal P&L or non-inventory capital purchases.
    c) ITCs in the HST SAVE account related to normal P&L and non-inventory capital purchases are recorded 100% into the 1592 variance account.
    d) ITCs in the HST SAVE account related to inventory purchases are recorded at 15.9% into the 1592 variance account. This percentage is based on the analysis of the typical level of inventory that was expensed versus capitalized. This allows BPI to record the ITCs on inventory that would be expensed to the P&L.

The following 3 steps deal with capital additions that would have had GST and PST prior to implementation of HST:

2) ITCs related to 2010 Capital Additions
    a) Inventory purchases capitalized from July 1, 2010 to December 31, 2010 were totaled by USoA account.
    b) BPI determined the PST amount that would have been paid on those capital additions and reported on the HST claims (8% x capitalized inventory).
    c) Based on the typical useful lives of these assets, BPI determined the amount of ITCs that would have been included in amortization expense on an annual basis had the 8% portion been capitalized. (8% x capitalized inventory / useful life).

d) The amount of the 2010 inventory charged to capital for the time period July 1st to December 31st was $6,073. This amount has been recorded to the 1592 variance account for 2010, 2011 and 2012.

3) ITCs related to 2011 Capital Additions

a) Inventory purchases capitalized from January 1, 2011 to December 31, 2011 were totaled by USoA account.

b) BPI determined the PST amount that would have been paid on those capital additions and reported on the HST claims (8% x capitalized inventory).

c) Based on the typical useful lives of these assets, BPI determined the amount of ITCs that would have been included in amortization expense on an annual basis had the 8% portion been capitalized. (8% x capitalized inventory / useful life).

d) The amount of the 2011 inventory charged to capital for the time period January 1st to December 31st was $4,127. This amount has been recorded to the 1592 variance account for 2011 and 2012. This number is lower than the last six months of 2010 as there were significant charges related to the Brantwood conversion and Powerline rebuild capital projects in late 2010.

4) ITCs related to 2012 Capital Additions

a) Inventory purchases capitalized from January 1, 2012 to December 31, 2012 were totaled by Board APH account.

b) BPI determined the PST amount that would have been paid on those capital additions and reported on the HST claims (8% x capitalized inventory).

c) Based on the typical useful lives of these assets, BPI determined the amount of ITCs that would have been included in amortization expense on an annual basis had the 8% portion been capitalized. (8% x capitalized inventory / useful life).

d) The amount of the 2012 inventory charged to capital for the time period January 1st to December 31st was $3,833. This amount has been recorded to the 1592 variance account for 2012.

5) ITCs related to City of Brantford Power Department purchases
    a) Prior to the restructuring on April 1, 2012, the City of Brantford Power Department used the same tax code within the Financial Information System to differentiate expenditures that had PST and GST prior to the implementation of HST. This code allows the 8% PST portion of the HST to be tracked to a distinct ITC account (HST SAVE) and the 5% GST portion of the HST to be tracked to the regular ITC account.
    b) The HST SAVE was reported on the monthly service level billing, allowing BPI to track 100% of the total to 1592.

6) ITCs related to shared services with the City of Brantford
    a) Purchases for various departments within the City of Brantford that provide services to BPI are analyzed on a monthly basis to estimate the reduction of charges resulting from the ability to claim the 8% PST amount that was previously included in the service level charges.
    b) The Finance, IT, Purchasing, Stores, Fleet, and Customer Service departments of the City of Brantford are included in the analysis.
    c) The percentages of each department vary – i.e.: Finance only included 65% of the estimated ITC savings since their costs were shared among the other Energy group of companies up to March 31, 2012.

The balance in this account is $134,922. BPI is requesting disposition of 50 per cent of the balance in this account or $67,461.

## ENERGY SALES AND COST OF POWER

Energy sales and the cost of power calculations are provided in Exhibit 2 Appendix D, as reported in the audited financial statements and the trial balance by USoA. BPI has no profit or loss resulting from the flow through energy revenues and expenses. Any temporary variances incurred are included in the RSVA balances.

BPI calculated the cost of power for the 2012 Bridge Year and 2013 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Report – May 1, 2013 to April 30, 2014, issued April 5, 2013. Should the Board publish a revised Regulated Price Plan Report prior to the Decision, BPI will update the electricity prices in the forecast.

## DEFERRAL & VARIANCE ACCOUNT BALANCES

The following Table 9.2 contains account balances from the 2012 Audited Financial Statements as at December 31, 2012 plus the forecasted interest through April 30, 2013. The amounts in Table 9.2 differ from 2012 year end balances for RRR Filing 2.1.7 Trial Balance as filed April 30, 2013 with the Board, because they include the forecasted interest through April 30, 2013.

**Table 9.2: December 31, 2012 Audited Balances – Deferral and Variance Accounts**

| Group 1 Deferral / Variance Accounts | | Principal | Interest | Projected Interest to April 30, 2013 | Total |
|---|---|---|---|---|---|
| 1580 | RSVA - Wholesale Market Service Charge | ($2,407,015) | ($34,038) | ($11,794) | ($2,452,847) |
| 1584 | RSVA - Retail Transmission Network Charge | $177,629 | ($181) | $870 | $178,318 |
| 1586 | RSVA - Retail Transmission Connection Charge | ($2,418) | ($6,663) | ($12) | ($9,093) |
| 1588 | RSVA - Power (excluding Global Adjustment) | ($1,772,558) | ($19,252) | ($8,686) | ($1,800,496) |
| 1588 | RSVA - Power - Sub-account - Global Adjustment | $783,497 | $22,577 | $3,839 | $809,913 |
| 1590 | Recovery of Regulatory Asset Balances | - | - | - | - |
| 1595 | Disposition and Recovery/Refund of Regulatory Balances (2010) | $169,541 | ($1,119,051) | $572 | ($948,938) |
| 1595 | Disposition and Recovery/Refund of Regulatory Balances (2011) | $166,113 | ($26,396) | $528 | $140,245 |
| Sub-Total | | ($2,885,211) | ($1,183,004) | ($14,683) | ($4,082,898) |
| | | | | | |
| **Group 2 Deferral / Variance Accounts** | | | | | |
| 1508 | Other Regulatory Assets - Sub-Account - OEB Cost Assessments | $ - | $ 946 | $ - | $ 946 |
| 1508 | Other Regulatory Assets - Sub-Account - Other | $ 650,855 | $ 16,213 | $ 3,189 | $ 670,257 |
| 1518 | Retail Cost Variance Account - Retail | $ 27,097 | $ 1,572 | $ 133 | $ 28,802 |
| 1525 | Misc. Deferred Debits | $ - | $ 82 | $ - | $ 82 |
| 1532 | Renewable Generation Connection OM&A Deferral Account | $ 8,666 | $ 127 | $ - | $ 8,793 |
| 1548 | Retail Cost Variance Account - STR | $ 266,366 | $ 55,958 | $ 1,305 | $ 323,629 |
| 1582 | RSVA - One-time | $ 264,945 | $ 87,009 | $ 1,298 | $ 353,252 |
| Sub-Total | | $ 1,217,929 | $ 161,907 | $ 5,925 | $ 1,385,761 |
| | | | | | |
| 1592 | PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | $ (131,903) | $ (2,373) | $ (646) | $ (134,922) |
| | | | | | |
| **Total Group 1 & Group 2 Accounts (including 1592)** | | **$ (1,799,185)** | **($1,023,470)** | **($9,404)** | **($2,832,059)** |

Table 9.3 provides the interest rates that have been used to calculate actual and forecasted carrying charges on the accounts in accordance with the methodology approved by the Board in the *Approval of Accounting Interest Rates Methodology for Regulatory Accounts* proceeding (EB-2006-0117 dated November 28, 2006).

**Table 9.3: Interest Rates Applied to Deferral and Variance Accounts**

| Quarter | Interest Rate Utilized |
|---|---|
| Q1 2005 | 7.25% |
| Q2 2005 | 7.25% |
| Q3 2005 | 7.25% |
| Q4 2005 | 7.25% |
| Q1 2006 | 7.25% |
| Q2 2006 | 4.14% |
| Q3 2006 | 4.59% |
| Q4 2006 | 4.59% |
| Q1 2007 | 4.59% |
| Q2 2007 | 4.59% |
| Q3 2007 | 4.59% |
| Q4 2007 | 5.14% |
| Q1 2008 | 5.14% |
| Q2 2008 | 4.08% |
| Q3 2008 | 3.35% |
| Q4 2008 | 3.35% |
| Q1 2009 | 2.45% |
| Q2 2009 | 1.00% |
| Q3 2009 | 0.55% |
| Q4 2009 | 0.55% |
| Q1 2010 | 0.55% |
| Q2 2010 | 0.55% |
| Q3 2010 | 0.89% |
| Q4 2010 | 1.20% |
| Q1 2011 | 1.47% |
| Q2 2011 | 1.47% |
| Q3 2011 | 1.47% |
| Q4 2011 | 1.47% |
| Q1 2012 | 1.47% |
| Q2 2012 | 1.47% |
| Q3 2012 | 1.47% |
| Q4 2012 | 1.47% |

## ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

BPI is requesting disposition of the variance accounts noted below according to the Board's *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (EDDVAR), Board File No. EB-2009-0046, which states that *"at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline."*

BPI has followed the guidelines in the Report of the Board. BPI requests disposition of the Group 1 and Group 2 balances over a one-year period. BPI has provided a continuity schedule of the accounts listed below in Appendix A of this Exhibit.

BPI is requesting the disposition of the following Group 1 and Group 2 Accounts shown in Tables 9.4, 9.5 and 9.6.

**Table 9.4: Group 1 Deferral / Variance Accounts – Excluding 1589 RSVA - Power - Sub-account - Global Adjustment (GA)**

| USoA | Description | Principal (Dec. 31, 2011) | Interest (Dec. 31, 2011) | Interest to Dec. 31, 2012 | Projected Interest to April 30, 2013 | Total Claim |
|---|---|---|---|---|---|---|
| 1580 | RSVA - Wholesale Market Service Charge | ($2,407,015) | ($3,856) | ($30,182) | ($11,794) | ($2,452,847) |
| 1584 | RSVA - Retail Transmission Network Charge | $177,629 | $2,934 | ($3,115) | $870 | $178,318 |
| 1586 | RSVA - Retail Transmission Connection Charge | ($2,418) | ($1,050) | ($5,613) | ($12) | ($9,093) |
| 1588 | RSVA - Power (excluding Global Adjustment) | ($1,772,558) | ($7,518) | ($11,734) | ($8,686) | ($1,800,496) |
| 1595 | Disposition and Recovery/Refund of Regulatory Balances (2010) | $169,541 | ($1,117,717) | ($1,334) | $572 | ($948,938) |
| 1595 | Disposition and Recovery/Refund of Regulatory Balances (2011) | $166,113 | ($27,008) | $612 | $528 | $140,245 |
| **Total** | | ($3,668,708) | ($1,154,215) | ($51,366) | ($18,522) | ($4,892,811) |

## Table 9.5: Group 2 Deferral / Variance Accounts

| USoA | Description | Principal (Dec. 31, 2011) | Interest (Dec. 31, 2011) | Interest to Dec. 31, 2012 | Projected Interest to April 30, 2013 | Total Claim |
|---|---|---|---|---|---|---|
| 1508 | Other Regulatory Assets - Sub-Account - OEB Cost Assessments | $ - | $ 946 | $ - | $ - | $ 946 |
| 1508 | Other Regulatory Assets - Sub-Account - Other 4 | $ 650,855 | $ 7,701 | $ 8,512 | $ 3,189 | $ 670,257 |
| 1518 | Retail Cost Variance Account - Retail | $ 27,097 | $ 1,098 | $ 474 | $ 133 | $ 28,802 |
| 1525 | Misc. Deferred Debits | $ - | $ 82 | $ - | $ - | $ 82 |
| 1532 | Renewable Generation Connection OM&A Deferral Account | $ 8,666 | $ 127 | $ - | $ - | $ 8,793 |
| 1548 | Retail Cost Variance Account - STR | $ 266,366 | $ 52,167 | $ 3,791 | $ 1,305 | $ 323,629 |
| 1582 | RSVA - One-time | $ 264,945 | $ 83,114 | $ 3,895 | $ 1,298 | $ 353,252 |
| Sub-Total | | $ 1,217,929 | $ 145,235 | $ 16,672 | $ 5,925 | $ 1,385,761 |
| 1592 | PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | $ (131,903) | $ (1,563) | $ (810) | $ (646) | $ (67,461) |
| **Total (including 1592)** | | **$ 1,086,026** | **$ 143,672** | **$ 15,862** | **$ 5,279** | **$ 1,318,300** |

## Table 9.6: 1589 RSVA - Power - Sub-account – GA

| USoA | Description | Principal (Dec. 31, 2011) | Interest (Dec. 31, 2011) | Interest to Dec. 31, 2012 | Projected Interest to April 30, 2013 | Total Claim |
|---|---|---|---|---|---|---|
| 1589 | RSVA - Power - Sub-account - Global Adjustment | $783,497 | $15,488 | $7,089 | $3,839 | $809,913 |

# METHOD OF DISPOSITION

## Allocators

BPI submits the following Allocators in Table 9.7, Table 9.8, Table 9.9 and Table 9.10 used to assign the Group 1, Group 2, 1589 RSVA - Power - Sub-account - GA and 1592 balances to rate each class.

**Table 9.7: Group 1 Allocation by Customer Class**

| Customer Class | Projected 2013 kWh | % Allocation | Amount Claimed |
|---|---|---|---|
| Residential | 280,913,502 | 31% | $ (1,494,173) |
| GS<50 kW | 97,535,297 | 11% | $ (518,788) |
| GS>50 kW | 531,977,718 | 58% | $ (2,829,579) |
| Unmetered Scattered Load | 1,454,727 | 0.16% | $ (7,738) |
| Sentinel Lighting | 443,490 | 0.05% | $ (2,358.9) |
| Street Lighting | 7,553,004 | 0.82% | $ (40,174.3) |
| Total | 919,877,738 | 100% | $ (4,892,811) |

**Table 9.8: Group 2 Allocation by Customer Class**

| Customer Class | Projected 2013 KWh | % Allocation | Amount Claimed |
|---|---|---|---|
| Residential | 280,913,502 | 31% | $ 423,186 |
| GS<50 kW | 97,535,297 | 11% | $ 146,933 |
| GS>50 kW | 531,977,718 | 58% | $ 801,404 |
| Unmetered Scattered Load | 1,454,727 | 0.16% | $ 2,191 |
| Sentinel Lighting | 443,490 | 0.05% | $ 668.1 |
| Street Lighting | 7,553,004 | 0.82% | $ 11,378.3 |
| Total | 919,877,738 | 100% | $ 1,385,761 |

**Table 9.9: Sub-Account 1589 RSVA - Power - Sub-account - GA Allocation by Customer Class**

| Customer Class | Projected 2013 Non-RPP kWh | % Allocation | Amount Claimed |
|---|---|---|---|
| Residential | 36,518,755 | 8% | $ 65,816 |
| GS<50 kW | 9,753,530 | 2% | $ 17,578 |
| GS>50 kW | 393,663,512 | 88% | $ 709,485 |
| Unmetered Scattered Load | 1,454,727 | 0.32% | $ 2,622 |
| Sentinel Lighting | 443,490 | 0.10% | $ 799.3 |
| Street Lighting | 7,553,004 | 1.68% | $ 13,612.5 |
| Total | 449,387,018 | 100% | $ 809,913 |

**Table 9.10: Account 1592 Allocation by Customer Class**

| Customer Class | Projected 2013 kWh | % Allocation | Amount Claimed |
|---|---|---|---|
| Residential | 280,913,502 | 31% | $ (20,601) |
| GS<50 kW | 97,535,297 | 11% | $ (7,153) |
| GS>50 kW | 531,977,718 | 58% | $ (39,014) |
| Unmetered Scattered Load | 1,454,727 | 0.16% | $ (107) |
| Sentinel Lighting | 443,490 | 0.05% | $ (32.5) |
| Street Lighting | 7,553,004 | 0.82% | $ (553.9) |
| Total | 919,877,738 | 100% | $ (67,461) |

**Calculation of Rate Riders**

Table 9.11 summarizes the variables used to determine the proposed regulatory asset rate rider by rate class for the Group 1 and Group 2 accounts, excluding the Non-RPP rate rider for the 1588 Sub-Account Global Adjustment. The billing determinants are based on the 2013 Test Year forecast load data and calculated for a one-year disposition period.

**Table 9.11: 2013 Deferral and Variance Account Rate Rider by Class**

| Customer Class | Group 1 Variance Accounts | Group 2 Variance Accounts | Total of Accounts 1562 & 1592 | Total Variance Accounts | Billing Determinnents Projected 2013 KWh | Projected 2013 KW | Recovery Period (Years) | Rate Rider |
|---|---|---|---|---|---|---|---|---|
| Residential | $ (1,494,173) | $ 423,186 | $ (20,601) | (1,091,589) | 280,913,502 | - | 1 | $ (0.0039) |
| GS<50 kW | $ (518,788) | $ 146,933 | $ (7,153) | (379,008) | 97,535,297 | - | 1 | $ (0.0039) |
| GS>50 kW | $ (2,829,579) | $ 801,404 | $ (39,014) | (2,067,188) | 531,977,718 | 1,354,270 | 1 | $ (1.5264) |
| Unmetered Scattered Load | $ (7,738) | $ 2,191 | $ (107) | (5,653) | 1,454,727 | - | 1 | $ (0.0039) |
| Sentinel Lighting | $ (2,359) | $ 668 | $ (33) | (1,723) | 443,490 | 1,356 | 1 | $ (1.2707) |
| Street Lighting | $ (40,174) | $ 11,378 | $ (553.9) | (29,350) | 7,553,004 | 23,455 | 1 | $ (1.2513) |
| **Total** | $ (4,892,811) | $ 1,385,761 | | (3,574,511) | 919,877,738 | 1,379,081 | | |

Table 9.12 summarizes the variables used to determine the proposed non-RPP global adjustment rate rider by rate class. BPI confirms that it pro-rated the IESO Global Adjustment Charge into the RPP and non-RPP portions. The billing determinants are based on the 2013 Test Year forecast load data and calculated for a one-year disposition period.

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

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

The details of the Proposed Rates and Bill Impacts are found at Exhibit 8, Tab 1, Schedule 8 and Appendix A.

## REQUEST FOR ACCOUNTING ORDER FOR IFRS IMPACTS

Since it is expected the actual adoption of IFRS will be implemented before the next scheduled Cost of Service Rate Application, BPI is requesting the following accounting order to authorize the creation of a variance account to capture the following specific difference related to the transition to IFRS.

**GAINS OR LOSSES ON DISPOSITION OF PROPERTY PLANT AND EQUIPMENT**

IFRS requires that gains or losses be recognized at the time an item of Property Plant and Equipment is disposed. The gains or losses must be recognized in the income statement and cannot be offset against any remaining Property Plant and Equipment balances or deferred on the balance sheet.

Under Canadian GAAP, BPI provides for certain pooled asset classes where gains or losses are not recognized at the time of disposition. As a result, no provisions have been made in the 2013 Cost of Service Rate Application for any gains or losses on disposition of pooled Property Plant and Equipment.

Since BPI anticipates the adoption of IFRS will take place prior to the next cost of service rate application, it is requesting a variance account be authorized to track any gains or losses on such Property Plant and Equipment dispositions effective with the date of IFRS adoption.

**OTHER POST EMPLOYMENT BENEFITS**

As a result of the 2012 restructuring of BPI, the Company has assumed the direct responsibility for approximately 55 additional active employees entitled to post-employment benefits. This change resulted in an increase in the accrued benefit obligation determined by the Company's actuaries at the end of 2012 to $2.1 million compared to the $898,000 reported in 2011.

BPI currently utilizes the corridor method of amortization to recognize actuarial gains and losses under existing Part V Canadian Generally Accepted Accounting Standards. Under this method, actuarial gains and losses in excess of 10% of the beginning accrued benefit obligations are amortized into expense on a straight line basis over the expected remaining lifetime of the inactive members receiving benefits under the plan (15 years). IFRS will require the Company to immediately recognize actuarial gains and losses as they occur with any transitional adjustment to the obligation to be recognized at time of transition to IFRS. It is expected that BPI will migrate to IFRS prior to the next Cost of Service Rate Application.

In the Board's *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, the Board indicated "that the option remains for these utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS."

With the recent addition of 55 direct employees as compared to a single active employee that was entitled to such Post-Employment Benefits before restructuring, BPI is unable to gauge or predict the volatility of future expected actuarial gains or losses as the pattern of claims experience for this new employee group has yet to be established. These new employees were formerly part of a much larger employee group within the City of Brantford. As a result, it is not possible to determine with any reliability how future actuarial estimates of Post-Employment Obligations will change for these active employees.

This is the case as some time will be required for the new BPI active employee groups to reflect in annual adjustments to the actuarial estimates for Post-Employment Obligations, the distinct demographic and claims experience profile for these employees.

In keeping with the Board's previous observations regarding the utilities' ability to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS, BPI submits that the current circumstances resulting from the corporate restructuring has made it impossible to establish reasonable forecasts of expected future actuarial gains or losses. BPI submits that the possibility of significant deviations in the benefit expense related to post employment obligations is possible but at this time, such values are not determinable. Such deviations should they materialize, could impact BPI both before and after the transition to MIFRS.

Without BPI having the benefit of some actual experience and evidence of year over year fluctuations in the actuarial estimate for the Post Employment Obligations of this particular group of active employees, it is not possible to determine the sensitivity of the actuarial estimate of Post-Employment Obligations to changes in actuarial assumptions, the impact of changing claims experience or the impact of the particular demographic make-up of the group. Without this information, it is not possible at this time to reliably forecast the expected level of annual benefit expense attributable to the active employees of BPI.

In order to address this uncertainty in a manner that balances the interest of the customers and of the utility, BPI is proposing that the amount to be recovered in the requested distribution rates be limited to the amount of estimated actual premiums paid for the existing retiree group entitled to such post-employment benefits. BPI submits this is appropriate as these costs are known and are in keeping with recent trending and were not impacted by the recent restructuring of BPI.

Since this approach will not recognize in distribution rates, any current year actuarial benefit expenses for the Post Employment Benefit Obligations of BPI active employees, BPI is requesting an accounting order be prepared that authorizes BPI to record in 1508 Other Regulatory Assets – Sub account – Post Employment Obligations Actuarial Benefit Expense Variance, the actual annual amount of post-employment benefit expenses attributable to the active employees of BPI. Furthermore, as prescribed in the Accounting Procedures Handbook, BPI requests the balance in this sub account be subject to carrying charges.

BPI submits that it would be prudent to use this account to monitor the magnitude and volatility of actual post-employment benefit expenses for active employees for a period of time sufficient to establish clear evidence of the amount of such costs that need to be prudently incorporated into BPI's cost of service and resulting distribution rates. Once this has been determined, BPI will request in a future rate proceeding the disposition of accumulated variances in this account. The values in this account will reflect the accumulated unrecovered benefit expenses inclusive of recognized actuarial gains and losses.

BPI has attached a draft Accounting Order as Appendix A to this Exhibit.

# APPENDIX A

# BPI DRAFT ACCOUNTING ORDER

**BPI Draft Accounting Order**

Brantford Power Inc. ("BPI") shall establish the following deferral and variance accounts as follows:

**A. Deferral Sub -Account "Impact of Gains or Losses on Disposition of Property Plant and Equipment of Account 1508 - Other Regulatory Assets** - effective January 1, 2014:

**Purpose**: to record following the introduction of International Financial Reporting Standards ("IFRS"), the value of gains or losses on the disposition of Property Plant and Equipment recognized at the time of disposal including subsequent interest improvements.

**A. Deferral Sub -Account "Other Post-Employment Benefits of Account 1508 - Other Regulatory Assets** - effective January 1, 2014:

**Purpose**: to record the variance between the annual benefit expense determined in accordance with IFRS and the annual benefit premiums paid for BPI's Other Post-Employment Benefits and subsequent interest improvements.

Detailed accounting entries for the above two sub-accounts are attached as Attachment A.

**Attachment A**
**Proposed Accounting Entries**

| **1. Impact of Gains or Losses on Disposition of Property Plant and Equipment of Sub Account 1508 - Other Regulatory Assets** | | |
|---|---|---|
| Dr or Cr | 1508 | Other Regulatory Assets - Impact of Gains or Losses on Disposition of Property Plant and Equipment |
| DR or CR | 5705<br>4355/4360 | Depreciation Expense sub account or Gain or Loss on Disposition of Utility and Other Property depending on if Like Assets or Readily Identifiable Assets |
| | | To record net gain or loss on early disposal of Property Plant and Equipment |
| | | |
| Dr or Cr | 1508 | Other Regulatory Assets - Impact of Gains or Losses on Disposition of Property Plant and Equipment |
| Dr or Cr | 4405/6035 | Interest and Dividend Income or Other Interest Expense |
| | | To record interest on the principal balance of the "Impact of Gains or Losses on Disposition of Property Plant and Equipment |

| **2. Impact of variance in Benefit Expense Sub Account 1508 - Other Regulatory Assets regarding Other Post Employment Obligations** | | |
|---|---|---|
| DR or CR | 1508 | Other Regulatory Assets - Impact of variance in Benefit Expense |
| Dr or Cr | 5646 | Employee Pensions and OPEB |
| | | To record net annual variance between benefit expense and actual benefit premiums related to Other Post Employment Obligations. |
| | | |
| Dr or Cr | 1508 | Other Regulatory Assets - Impact of variance in Benefit Expense |
| Dr or Cr | 4405/6035 | Interest and Dividend Income or Other Interest Expense |
| | | To record interest on the principal balance of the " Other Regulatory Assets - Impact of variance in Benefit Expense" |

# APPENDIX B

# COMPLETED DVA CONTINUITY SCHEDULE

| Account Descriptions | Account Number | 2006 Opening Principal Amounts as of Jan-1-06 | Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3] | Board-Approved Disposition during 2006 [1, 1A] | Adjustments during 2006 - other [2] | Closing Principal Balance as of Dec-31-06 | Opening Interest Amounts as of Jan-1-06 | Interest Jan-1 to Dec-31-06 | Board-Approved Disposition during 2006 [1, 1A] | Adjustments during 2006 - other [2] | Closing Interest Amounts as of Dec-31-06 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | $ - | | | -$ 67,158 | -$ 67,158 | $ - | | | -$ 911 | -$ 911 |
| RSVA - Wholesale Market Service Charge | 1580 | $ - | | | -$ 719,976 | -$ 719,976 | $ - | | | -$ 66,152 | -$ 66,152 |
| RSVA - Retail Transmission Network Charge | 1584 | $ - | | | $ 538,582 | $ 538,582 | $ - | | | -$ 24,092 | -$ 24,092 |
| RSVA - Retail Transmission Connection Charge | 1586 | $ - | | | -$ 39,901 | -$ 39,901 | $ - | | | -$ 25,366 | -$ 25,366 |
| RSVA - Power (excluding Global Adjustment) | 1588 | $ - | | | -$ 426,853 | -$ 426,853 | $ - | | | -$ 362,239 | -$ 362,239 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | $ - | | | $ 500,892 | $ 500,892 | $ - | | | -$ 20,932 | -$ 20,932 |
| Recovery of Regulatory Asset Balances | 1590 | $ - | | | $ 1,169,909 | $ 1,169,909 | $ - | | | $ 2,014,964 | $ 2,014,964 |
| Disposition and Recovery/Refund of Regulatory Balances (2008)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2011)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2010)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | $ - | $ - | $ - | $ 955,495 | $ 955,495 | $ - | $ - | $ - | $ 1,515,272 | $ 1,515,272 |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | $ - | $ - | $ - | $ 454,603 | $ 454,603 | $ - | $ - | $ - | $ 1,536,204 | $ 1,536,204 |
| **RSVA - Power - Sub-account - Global Adjustment** | **1588** | $ - | $ - | $ - | $ 500,892 | $ 500,892 | $ - | $ - | $ - | -$ 20,932 | -$ 20,932 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - OEB Cost Assessments | 1508 | $ - | | | $ 82,289 | $ 82,289 | $ - | | | $ 2,330 | $ 2,330 |
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - Retail | 1518 | $ - | | | $ 19,105 | $ 19,105 | $ - | | | -$ 1,076 | -$ 1,076 |
| Misc. Deferred Debits | 1525 | $ - | | | $ 7,099 | $ 7,099 | $ - | | | $ 341 | $ 341 |
| Renewable Generation Connection Capital Deferral Account | 1531 | | | | | $ - | $ - | | | | $ - |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | | | | $ - | $ - | | | | $ - |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | | | | | $ - | $ - | | | | $ - |
| Smart Grid Capital Deferral Account | 1534 | | | | | $ - | $ - | | | | $ - |
| Smart Grid OM&A Deferral Account | 1535 | | | | | $ - | $ - | | | | $ - |
| Smart Grid Funding Adder Deferral Account | 1536 | | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - STR | 1548 | $ - | | | $ 197,249 | $ 197,249 | $ - | | | $ 27,464 | $ 27,464 |
| Board-Approved CDM Variance Account | 1567 | | | | | | | | | | |
| Extra-Ordinary Event Costs | 1572 | $ - | | | | $ - | $ - | | | | $ - |
| Deferred Rate Impact Amounts | 1574 | $ - | | | | $ - | $ - | | | | $ - |
| RSVA - One-time | 1582 | $ - | | | $ 264,945 | $ 264,945 | $ - | | | $ 51,023 | $ 51,023 |
| Other Deferred Credits | 2425 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 2 Sub-Total** | | $ - | $ - | $ - | $ 570,687 | $ 570,687 | $ - | $ - | $ - | $ 80,082 | $ 80,082 |
| Deferred Payments in Lieu of Taxes | 1562 | $ - | | | -$ 5,218,693 | -$ 5,218,693 | $ - | | | -$ 1,099,122 | -$ 1,099,122 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | $ - | $ - | $ - | -$ 3,692,511 | -$ 3,692,511 | $ - | $ - | $ - | $ 496,232 | $ 496,232 |
| **Special Purpose Charge Assessment Variance Account[9]** | **1521** | | | | | | | | | | |
| **LRAM Variance Account** | **1568** | | | | | | | | | | |
| **Total including Account 1521 and Account 1568** | | $ - | $ - | $ - | -$ 3,692,511 | -$ 3,692,511 | $ - | $ - | $ - | $ 496,232 | $ 496,232 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11] | 1555 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11] | 1555 | $ - | | | -$ 80,490 | -$ 80,490 | $ - | | | -$ 1,042 | -$ 1,042 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11] | 1555 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Meter OM&A Variance[11] | 1556 | $ - | | | $ 12,808 | $ 12,808 | $ - | | | $ 290 | $ 290 |
| **The following is not included in the total claim but are included on a memo basis:** | | | | | | | | | | | |
| Deferred PILs Contra Account [5] | 1563 | $ - | | | $ 5,218,693 | $ 5,218,693 | $ - | | | $ 1,099,122 | $ 1,099,122 |
| IFRS-CGAAP Transition PP&E Amounts[10] | 1575 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery of Regulatory Balances[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |

| Account Descriptions | Account Number | 2007 Opening Principal Amounts as of Jan-1-07 | Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3] | Board-Approved Disposition during 2007 | Adjustments during 2007 - other [2] | Closing Principal Balance as of Dec-31-07 | Opening Interest Amounts as of Jan-1-07 | Interest Jan-1 to Dec-31-07 | Board-Approved Disposition during 2007 | Adjustments during 2007 - other [2] | Closing Interest Amounts as of Dec-31-07 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | -$ 67,158 | -$ 101,406 | | | -$ 168,564 | -$ 911 | -$ 5,443 | | | -$ 6,354 |
| RSVA - Wholesale Market Service Charge | 1580 | -$ 719,976 | -$ 1,320,511 | | | -$ 2,040,487 | -$ 66,152 | -$ 62,813 | | | -$ 128,965 |
| RSVA - Retail Transmission Network Charge | 1584 | $ 538,582 | -$ 226,535 | | | $ 312,047 | -$ 24,092 | $ 22,866 | | | -$ 1,226 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$ 39,901 | -$ 810,410 | | | -$ 850,311 | -$ 25,366 | -$ 19,690 | | | -$ 45,056 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$ 426,853 | -$ 220,767 | | | -$ 647,620 | -$ 362,239 | -$ 26,115 | | | -$ 388,354 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | $ 500,892 | -$ 198,972 | | | $ 301,920 | -$ 20,932 | $ 17,536 | | | -$ 3,396 |
| Recovery of Regulatory Asset Balances | 1590 | $ 1,169,909 | -$ 2,588,010 | | | -$ 1,418,101 | $ 2,014,964 | -$ 5,615 | | | $ 2,009,349 |
| Disposition and Recovery/Refund of Regulatory Balances (2008)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2011)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2010)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | $ 955,495 | -$ 5,466,611 | $ - | $ - | -$ 4,511,116 | $ 1,515,272 | -$ 79,274 | $ - | $ - | $ 1,435,998 |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | $ 454,603 | -$ 5,267,639 | $ - | $ - | -$ 4,813,036 | $ 1,536,204 | -$ 96,810 | $ - | $ - | $ 1,439,394 |
| **RSVA - Power - Sub-account - Global Adjustment** | **1588** | $ 500,892 | -$ 198,972 | $ - | $ - | $ 301,920 | -$ 20,932 | $ 17,536 | $ - | $ - | -$ 3,396 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - OEB Cost Assessments | 1508 | $ 82,289 | | | | $ 82,289 | $ 2,330 | $ 3,890 | | | $ 6,220 |
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - Retail | 1518 | $ 19,105 | -$ 605 | | | $ 18,500 | -$ 1,076 | $ 699 | | | -$ 377 |
| Misc. Deferred Debits | 1525 | $ 7,099 | | | | $ 7,099 | $ 341 | $ 336 | | | $ 677 |
| Renewable Generation Connection Capital Deferral Account | 1531 | | | | | $ - | | | | | $ - |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | | | | $ - | | | | | $ - |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | | | | | $ - | | | | | $ - |
| Smart Grid Capital Deferral Account | 1534 | | | | | $ - | | | | | $ - |
| Smart Grid OM&A Deferral Account | 1535 | | | | | $ - | | | | | $ - |
| Smart Grid Funding Adder Deferral Account | 1536 | | | | | $ - | | | | | $ - |
| Retail Cost Variance Account - STR | 1548 | $ 197,249 | $ 44,115 | | | $ 241,364 | $ 27,464 | $ 10,719 | | | $ 38,183 |
| Board-Approved CDM Variance Account | 1567 | | | | | | | | | | |
| Extra-Ordinary Event Costs | 1572 | $ - | | | | $ - | $ - | | | | $ - |
| Deferred Rate Impact Amounts | 1574 | $ - | | | | $ - | $ - | | | | $ - |
| RSVA - One-time | 1582 | $ 264,945 | | | | $ 264,945 | $ 51,023 | $ 12,525 | | | $ 63,548 |
| Other Deferred Credits | 2425 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 2 Sub-Total** | | $ 570,687 | $ 43,510 | $ - | $ - | $ 614,197 | $ 80,082 | $ 28,169 | $ - | $ - | $ 108,251 |
| Deferred Payments in Lieu of Taxes | 1562 | -$ 5,218,693 | | | | -$ 5,218,693 | -$ 1,099,122 | -$ 246,714 | | | -$ 1,345,836 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$ 3,692,511 | -$ 5,423,101 | $ - | $ - | -$ 9,115,612 | $ 496,232 | -$ 297,819 | $ - | $ - | $ 198,413 |
| **Special Purpose Charge Assessment Variance Account[9]** | **1521** | | | | | | | | | | |
| **LRAM Variance Account** | **1568** | | | | | | | | | | |
| **Total including Account 1521 and Account 1568** | | -$ 3,692,511 | -$ 5,423,101 | $ - | $ - | -$ 9,115,612 | $ 496,232 | -$ 297,819 | $ - | $ - | $ 198,413 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11] | 1555 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11] | 1555 | -$ 80,490 | -$ 121,941 | | | -$ 202,431 | -$ 1,042 | -$ 6,518 | | | -$ 7,560 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11] | 1555 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Meter OM&A Variance[11] | 1556 | $ 12,808 | $ 12,763 | | | $ 25,571 | $ 290 | $ 898 | | | $ 1,188 |
| **The following is not included in the total claim but are included on a memo basis:** | | | | | | | | | | | |
| Deferred PILs Contra Account [5] | 1563 | $ 5,218,693 | | | | $ 5,218,693 | $ 1,099,122 | $ 246,714 | | | $ 1,345,836 |
| IFRS-CGAAP Transition PP&E Amounts[10] | 1575 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery of Regulatory Balances[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |

| Account Descriptions | Account Number | 2008 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Opening Principal Amounts as of Jan-1-08 | Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3] | Board-Approved Disposition during 2008 | Adjustments during 2008 - other [2] | Closing Principal Balance as of Dec-31-08 | Opening Interest Amounts as of Jan-1-08 | Interest Jan-1 to Dec-31-08 | Board-Approved Disposition during 2008 | Adjustments during 2008 - other [2] | Closing Interest Amounts as of Dec-31-08 |
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | -$ 168,564 | -$ 69,787 | -$ 207,797 | | -$ 30,554 | -$ 6,354 | -$ 5,932 | -$ 9,545 | | -$ 2,741 |
| RSVA - Wholesale Market Service Charge | 1580 | -$ 2,040,487 | -$ 595,922 | | | -$ 2,636,409 | -$ 128,965 | -$ 93,357 | $ - | | -$ 222,322 |
| RSVA - Retail Transmission Network Charge | 1584 | -$ 312,047 | -$ 871,955 | | | -$ 559,908 | -$ 1,226 | -$ 7,188 | $ - | | -$ 8,414 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$ 850,311 | -$ 898,208 | | | -$ 1,748,519 | -$ 45,056 | -$ 51,859 | $ - | | -$ 96,915 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$ 647,620 | -$ 652,471 | | | -$ 1,300,091 | -$ 388,354 | -$ 39,491 | $ - | | -$ 427,845 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | $ 301,920 | $ 481,714 | | | $ 783,634 | -$ 3,396 | $ 13,916 | $ - | | $ 10,520 |
| Recovery of Regulatory Asset Balances | 1590 | -$ 1,418,101 | -$ 1,765,613 | | | -$ 3,183,714 | $ 2,009,349 | -$ 95,838 | $ - | | $ 1,913,511 |
| Disposition and Recovery/Refund of Regulatory Balances (2008)[7] | 1595 | $ - | $ 253,755 | $ 333,301 | | -$ 79,546 | $ - | -$ 2,805 | $ 210,540 | | -$ 213,345 |
| Disposition and Recovery/Refund of Regulatory Balances (2011)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2010)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | -$ 4,511,116 | -$ 4,118,487 | $ 125,504 | $ - | -$ 8,755,107 | $ 1,435,998 | -$ 282,554 | $ 200,995 | $ - | $ 952,449 |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | -$ 4,813,036 | -$ 4,600,201 | $ 125,504 | $ - | -$ 9,538,741 | $ 1,439,394 | -$ 296,470 | $ 200,995 | $ - | $ 941,929 |
| **RSVA - Power - Sub-account - Global Adjustment** | **1588** | $ 301,920 | $ 481,714 | $ - | $ - | $ 783,634 | -$ 3,396 | $ 13,916 | $ - | $ - | $ 10,520 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - OEB Cost Assessments | 1508 | $ 82,289 | | $ 82,289 | | $ - | $ 6,220 | $ 2,356 | $ 7,630 | | $ 946 |
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - Retail | 1518 | $ 18,500 | $ 1,492 | | | $ 19,992 | -$ 377 | $ 414 | | | $ 37 |
| Misc. Deferred Debits | 1525 | $ 7,099 | | $ 7,099 | | $ - | $ 677 | $ 203 | $ 798 | | $ 82 |
| Renewable Generation Connection Capital Deferral Account | 1531 | | | | | $ - | | | | | $ - |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | | | | $ - | | | | | $ - |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | | | | | $ - | | | | | $ - |
| Smart Grid Capital Deferral Account | 1534 | | | | | $ - | | | | | $ - |
| Smart Grid OM&A Deferral Account | 1535 | | | | | $ - | | | | | $ - |
| Smart Grid Funding Adder Deferral Account | 1536 | | | | | $ - | | | | | $ - |
| Retail Cost Variance Account - STR | 1548 | $ 241,364 | -$ 38,027 | | | $ 203,337 | $ 38,183 | $ 6,228 | | | $ 44,411 |
| Board-Approved CDM Variance Account | 1567 | | | | | | | | | | |
| Extra-Ordinary Event Costs | 1572 | $ - | | | | $ - | $ - | | | | $ - |
| Deferred Rate Impact Amounts | 1574 | $ - | | | | $ - | $ - | | | | $ - |
| RSVA - One-time | 1582 | $ 264,945 | | | | $ 264,945 | $ 63,548 | $ 10,545 | | | $ 74,093 |
| Other Deferred Credits | 2425 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 2 Sub-Total** | | $ 614,197 | -$ 36,535 | $ 89,388 | $ - | $ 488,274 | $ 108,251 | $ 19,746 | $ 8,428 | $ - | $ 119,569 |
| Deferred Payments in Lieu of Taxes | 1562 | -$ 5,218,693 | | | | -$ 5,218,693 | -$ 1,345,836 | -$ 207,704 | | | -$ 1,553,540 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$ 9,115,612 | -$ 4,155,022 | $ 214,892 | $ - | -$ 13,485,526 | $ 198,413 | -$ 470,512 | $ 209,423 | $ - | -$ 481,522 |
| **Special Purpose Charge Assessment Variance Account[9]** | **1521** | | | | | | | | | | |
| **LRAM Variance Account** | **1568** | | | | | | | | | | |
| **Total including Account 1521 and Account 1568** | | -$ 9,115,612 | -$ 4,155,022 | $ 214,892 | $ - | -$ 13,485,526 | $ 198,413 | -$ 470,512 | $ 209,423 | $ - | -$ 481,522 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11] | 1555 | $ - | $ 14,945 | | | $ 14,945 | $ - | | | | $ - |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11] | 1555 | -$ 202,431 | -$ 123,807 | | | -$ 326,238 | -$ 7,560 | -$ 10,088 | | | -$ 17,648 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11] | 1555 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Meter OM&A Variance[11] | 1556 | $ 25,571 | $ 19,371 | | | $ 44,942 | $ 1,188 | $ 1,177 | | | $ 2,365 |
| **The following is not included in the total claim but are included on a memo basis:** | | | | | | | | | | | |
| Deferred PILs Contra Account [5] | 1563 | $ 5,218,693 | | | | $ 5,218,693 | $ 1,345,836 | $ 207,704 | $ - | $ - | $ 1,553,540 |
| IFRS-CGAAP Transition PP&E Amounts[10] | 1575 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery of Regulatory Balances[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |

| Account Descriptions | Account Number | 2009 Opening Principal Amounts as of Jan-1-09 | Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3] | Board-Approved Disposition during 2009 | Adjustments during 2009 - other [2] | Closing Principal Balance as of Dec-31-09 | Opening Interest Amounts as of Jan-1-09 | Interest Jan-1 to Dec-31-09 | Board-Approved Disposition during 2009 | Adjustments during 2009 - other [2] | Closing Interest Amounts as of Dec-31-09 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | -$ 30,554 | | | | -$ 30,554 | -$ 2,741 | -$ 347 | | | -$ 3,088 |
| RSVA - Wholesale Market Service Charge | 1580 | -$ 2,636,409 | -$ 321,979 | | | -$ 2,958,388 | -$ 222,322 | -$ 30,928 | | | -$ 253,250 |
| RSVA - Retail Transmission Network Charge | 1584 | -$ 559,908 | -$ 375,459 | | | -$ 935,367 | -$ 8,414 | -$ 6,617 | | | -$ 15,031 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$ 1,748,519 | -$ 815,692 | | | -$ 2,564,211 | -$ 96,915 | -$ 21,304 | | | -$ 118,219 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$ 1,300,091 | -$ 950,491 | | | -$ 2,250,582 | -$ 427,845 | -$ 19,524 | | | -$ 447,369 |
| RSVA - Power - Sub-account - Global Adjustment | 1589 | $ 783,634 | $ 1,257,873 | | | $ 2,041,507 | $ 10,520 | $ 12,414 | | | $ 22,934 |
| Recovery of Regulatory Asset Balances | 1590 | -$ 3,183,714 | | | | -$ 3,183,714 | $ 1,913,511 | -$ 11,795 | | | $ 1,901,716 |
| Disposition and Recovery/Refund of Regulatory Balances (2008)[7] | 1595 | -$ 79,546 | $ 57,532 | | | -$ 22,014 | -$ 213,345 | -$ 253 | | $ 210,540 | -$ 3,058 |
| Disposition and Recovery/Refund of Regulatory Balances (2011)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2010)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | -$ 8,755,107 | -$ 1,148,216 | $ - | $ - | -$ 9,903,323 | $ 952,449 | -$ 78,354 | $ - | $ 210,540 | $ 1,084,635 |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | -$ 9,538,741 | -$ 2,406,089 | $ - | $ - | -$ 11,944,830 | $ 941,929 | -$ 90,768 | $ - | $ 210,540 | $ 1,061,701 |
| **RSVA - Power - Sub-account - Global Adjustment** | **1588** | $ 783,634 | $ 1,257,873 | $ - | $ - | $ 2,041,507 | $ 10,520 | $ 12,414 | $ - | $ - | $ 22,934 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - OEB Cost Assessments | 1508 | $ - | | | | $ - | $ 946 | | | | $ 946 |
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - Retail | 1518 | $ 19,992 | $ 14,707 | | | $ 34,699 | $ 37 | $ 266 | | | $ 303 |
| Misc. Deferred Debits | 1525 | $ - | | | | $ - | $ 82 | | | | $ 82 |
| Renewable Generation Connection Capital Deferral Account | 1531 | | | | | $ - | $ - | | | | $ - |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | | | | $ - | $ - | | | | $ - |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | | | | | $ - | $ - | | | | $ - |
| Smart Grid Capital Deferral Account | 1534 | | | | | $ - | $ - | | | | $ - |
| Smart Grid OM&A Deferral Account | 1535 | | | | | $ - | $ - | | | | $ - |
| Smart Grid Funding Adder Deferral Account | 1536 | | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - STR | 1548 | $ 203,337 | $ 17,592 | | | $ 220,929 | $ 44,411 | $ 2,372 | | | $ 46,783 |
| Board-Approved CDM Variance Account | 1567 | | | | | | | | | | $ - |
| Extra-Ordinary Event Costs | 1572 | $ - | | | | $ - | $ - | | | | $ - |
| Deferred Rate Impact Amounts | 1574 | $ - | | | | $ - | $ - | | | | $ - |
| RSVA - One-time | 1582 | $ 264,945 | | | | $ 264,945 | $ 74,093 | $ 3,014 | | | $ 77,107 |
| Other Deferred Credits | 2425 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 2 Sub-Total** | | $ 488,274 | $ 32,299 | $ - | $ - | $ 520,573 | $ 119,569 | $ 5,652 | $ - | $ - | $ 125,221 |
| Deferred Payments in Lieu of Taxes | 1562 | -$ 5,218,693 | | | | -$ 5,218,693 | -$ 1,553,540 | -$ 59,362 | | | -$ 1,612,902 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$ 13,485,526 | -$ 1,115,917 | $ - | $ - | -$ 14,601,443 | -$ 481,522 | -$ 132,064 | $ - | $ 210,540 | -$ 403,046 |
| **Special Purpose Charge Assessment Variance Account[9]** | **1521** | | | | | | | | | | |
| **LRAM Variance Account** | **1568** | | | | | | | | | | |
| **Total including Account 1521 and Account 1568** | | -$ 13,485,526 | -$ 1,115,917 | $ - | $ - | -$ 14,601,443 | -$ 481,522 | -$ 132,064 | $ - | $ 210,540 | -$ 403,046 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11] | 1555 | $ 14,945 | $ 1,750,889 | | | $ 1,765,834 | $ - | $ 2,144 | $ - | | $ 2,144 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11] | 1555 | -$ 326,238 | -$ 339,249 | | | -$ 665,487 | -$ 17,648 | -$ 4,454 | | | -$ 22,102 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11] | 1555 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Meter OM&A Variance[11] | 1556 | $ 44,942 | $ 29,756 | | | $ 74,698 | $ 2,365 | $ 548 | | | $ 2,913 |
| **The following is not included in the total claim but are included on a memo basis:** | | | | | | | | | | | |
| Deferred PILs Contra Account [5] | 1563 | $ 5,218,693 | | | | $ 5,218,693 | $ 1,553,540 | $ 59,362 | | | $ 1,612,902 |
| IFRS-CGAAP Transition PP&E Amounts[10] | 1575 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery of Regulatory Balances[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |

| Account Descriptions | Account Number | 2010<br>Opening Principal Amounts as of Jan-1-10 | Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3] | Board-Approved Disposition during 2010 | Adjustments during 2010 - other [2] | Closing Principal Balance as of Dec-31-10 | Opening Interest Amounts as of Jan-1-10 | Interest Jan-1 to Dec-31-10 | Board-Approved Disposition during 2010 | Adjustments during 2010 - other [2] | Closing Interest Amounts as of Dec-31-10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Group 1 Accounts** | | | | | | | | | | | |
| LV Variance Account | 1550 | -$ 30,554 | | -$ 30,554 | | $ - | -$ 3,088 | -$ 53 | -$ 3,141 | | $ - |
| RSVA - Wholesale Market Service Charge | 1580 | -$ 2,958,388 | -$ 1,063,709 | -$ 2,636,409 | | -$ 1,385,688 | -$ 253,250 | -$ 11,935 | -$ 256,900 | | -$ 8,285 |
| RSVA - Retail Transmission Network Charge | 1584 | -$ 935,367 | -$ 1,089,431 | -$ 559,908 | | -$ 1,464,890 | -$ 15,031 | -$ 7,688 | -$ 15,757 | | -$ 6,962 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$ 2,564,211 | -$ 1,121,986 | -$ 1,748,519 | | -$ 1,937,678 | -$ 118,219 | -$ 13,928 | -$ 119,848 | | -$ 12,299 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$ 2,250,582 | $ 337,568 | -$ 1,300,091 | | -$ 612,923 | -$ 447,369 | -$ 30,538 | -$ 444,896 | | -$ 33,011 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | $ 2,041,507 | -$ 816,045 | $ 705,850 | | $ 519,612 | $ 22,934 | $ 29,383 | $ 43,939 | | $ 8,378 |
| Recovery of Regulatory Asset Balances | 1590 | -$ 3,183,714 | | -$ 3,183,714 | | $ - | $ 1,901,716 | -$ 1,900 | $ 1,899,816 | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2008)[7] | 1595 | -$ 22,014 | | | | -$ 22,014 | -$ 3,058 | -$ 175 | | | -$ 3,233 |
| Disposition and Recovery/Refund of Regulatory Balances (2011)[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2010)[7] | 1595 | $ - | $ 2,283,276 | $ 8,753,345 | $ 2,146,903 | -$ 4,323,166 | $ - | -$ 33,339 | -$ 1,103,213 | -$ 2,146,903 | -$ 1,077,029 |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | -$ 9,903,323 | -$ 1,470,327 | $ - | $ 2,146,903 | -$ 9,226,747 | $ 1,084,635 | -$ 70,173 | $ - | -$ 2,146,903 | -$ 1,132,441 |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | -$ 11,944,830 | -$ 654,282 | -$ 705,850 | $ 2,146,903 | -$ 9,746,359 | $ 1,061,701 | -$ 99,556 | -$ 43,939 | -$ 2,146,903 | -$ 1,140,819 |
| **RSVA - Power - Sub-account - Global Adjustment** | **1588** | $ 2,041,507 | -$ 816,045 | $ 705,850 | $ - | $ 519,612 | $ 22,934 | $ 29,383 | $ 43,939 | $ - | $ 8,378 |
| **Group 2 Accounts** | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - OEB Cost Assessments | 1508 | $ - | | | | $ - | $ 946 | | | | $ 946 |
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | $ - | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $ - | $ 387,334 | | | $ 387,334 | $ - | $ 1,098 | | | $ 1,098 |
| Retail Cost Variance Account - Retail | 1518 | $ 34,699 | $ 1,477 | | | $ 36,176 | $ 303 | $ 272 | | | $ 575 |
| Misc. Deferred Debits | 1525 | $ - | | | | $ - | $ 82 | | | | $ 82 |
| Renewable Generation Connection Capital Deferral Account | 1531 | $ - | $ 8,666 | | | $ 8,666 | $ - | | | | $ - |
| Renewable Generation Connection OM&A Deferral Account | 1532 | $ - | | | | $ - | $ - | | | | $ - |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Grid Capital Deferral Account | 1534 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Grid OM&A Deferral Account | 1535 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Grid Funding Adder Deferral Account | 1536 | $ - | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - STR | 1548 | $ 220,929 | $ 14,667 | | | $ 235,596 | $ 46,783 | $ 1,825 | | | $ 48,608 |
| Board-Approved CDM Variance Account | 1567 | | | | | $ - | $ - | | | | $ - |
| Extra-Ordinary Event Costs | 1572 | $ - | | | | $ - | $ - | | | | $ - |
| Deferred Rate Impact Amounts | 1574 | $ - | | | | $ - | $ - | | | | $ - |
| RSVA - One-time | 1582 | $ 264,945 | | | | $ 264,945 | $ 77,107 | $ 2,113 | | | $ 79,220 |
| Other Deferred Credits | 2425 | $ - | | | | $ - | $ - | | | | $ - |
| **Group 2 Sub-Total** | | $ 520,573 | $ 412,144 | $ - | $ - | $ 932,717 | $ 125,221 | $ 5,308 | $ - | $ - | $ 130,529 |
| Deferred Payments in Lieu of Taxes | 1562 | -$ 5,218,693 | | | | -$ 5,218,693 | -$ 1,612,902 | -$ 41,619 | | | -$ 1,654,521 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | $ - | -$ 36,700 | | | -$ 36,700 | $ - | | | | $ - |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$ 14,601,443 | -$ 1,094,883 | $ - | $ 2,146,903 | -$ 13,549,423 | -$ 403,046 | -$ 106,484 | $ - | -$ 2,146,903 | -$ 2,656,433 |
| **Special Purpose Charge Assessment Variance Account[9]** | **1521** | | $ 135,736 | | | $ 135,736 | | $ 1,100 | | | $ 1,100 |
| **LRAM Variance Account** | **1568** | | | | | $ - | | | | | $ - |
| **Total including Account 1521 and Account 1568** | | -$ 14,601,443 | -$ 959,147 | $ - | $ 2,146,903 | -$ 13,413,687 | -$ 403,046 | -$ 105,384 | $ - | -$ 2,146,903 | -$ 2,655,333 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11] | 1555 | $ 1,765,834 | $ 2,781,626 | | | $ 4,547,460 | $ 2,144 | $ 26,739 | | | $ 28,883 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11] | 1555 | -$ 665,487 | -$ 765,601 | | | -$ 1,431,088 | -$ 22,102 | -$ 8,230 | | | -$ 30,332 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11] | 1555 | $ - | | | | $ - | $ - | | | | $ - |
| Smart Meter OM&A Variance[11] | 1556 | $ 74,698 | $ 326,810 | | | $ 401,508 | $ 2,913 | $ 813 | | | $ 3,726 |
| **The following is not included in the total claim but are included on a memo basis:** | | | | | | | | | | | |
| Deferred PILs Contra Account [5] | 1563 | $ 5,218,693 | | | | $ 5,218,693 | $ 1,612,902 | $ 41,619 | | | $ 1,654,521 |
| IFRS-CGAAP Transition PP&E Amounts[10] | 1575 | $ - | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account | 1592 | $ - | $ 36,700 | | | $ 36,700 | $ - | | | | $ - |
| Disposition and Recovery of Regulatory Balances[7] | 1595 | $ - | | | | $ - | $ - | | | | $ - |

| Account Descriptions | Account Number | Opening Principal Amounts as of Jan-1-11 | Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3] | Board-Approved Disposition during 2011 | Other [2] Adjustments during Q1 2011 | Other [2] Adjustments during Q2 2011 | Other [2] Adjustments during Q3 2011 | Other [2] Adjustments during Q4 2011 | Closing Principal Balance as of Dec-31-11 | Opening Interest Amounts as of Jan-1-11 | Interest Jan-1 to Dec-31-11 | Board-Approved Disposition during 2011 | Adjustments during 2011 - other [2] | Closing Interest Amounts as of Dec-31-11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **2011** | | | | | | | | | | | | |
| **Group 1 Accounts** | | | | | | | | | | | | | | |
| LV Variance Account | 1550 | $ - | | | | | | | $ - | $ - | | | | $ - |
| RSVA - Wholesale Market Service Charge | 1580 | -$ 1,385,688 | -$ 1,067,882 | -$ 321,979 | | | | -$ 1,339,133 | -$ 3,470,724 | -$ 8,285 | -$ 24,705 | -$ 4,383 | | -$ 28,607 |
| RSVA - Retail Transmission Network Charge | 1584 | -$ 1,464,890 | -$ 15,406 | -$ 375,459 | | | | $ 193,035 | -$ 911,802 | -$ 6,962 | -$ 18,419 | -$ 4,093 | | -$ 21,288 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$ 1,937,678 | -$ 104,766 | -$ 815,693 | | | | $ 102,348 | -$ 1,124,403 | -$ 12,299 | -$ 23,041 | -$ 9,805 | | -$ 25,535 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$ 612,923 | -$ 393,160 | -$ 950,491 | | | | -$ 1,379,398 | -$ 1,434,990 | -$ 33,011 | -$ 902 | -$ 14,463 | | -$ 19,450 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | $ 519,612 | $ 595,937 | $ 1,312,515 | | | | $ 187,560 | -$ 9,406 | $ 8,378 | -$ 53 | $ 16,863 | | -$ 8,538 |
| Recovery of Regulatory Asset Balances | 1590 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2008)[7] | 1595 | -$ 22,014 | | -$ 22,014 | | | | | $ - | -$ 3,233 | -$ 48 | -$ 3,281 | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2011)[7] | 1595 | $ - | $ 902,349 | $ 1,173,121 | | | | $ 436,885 | $ 166,113 | $ - | -$ 7,846 | $ 19,162 | | -$ 27,008 |
| Disposition and Recovery/Refund of Regulatory Balances (2010)[7] | 1595 | -$ 4,323,166 | $ 3,389,140 | | | | | $ 1,103,567 | $ 169,541 | -$ 1,077,029 | -$ 40,688 | | | -$ 1,117,717 |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | -$ 9,226,747 | $ 3,306,212 | $ - | $ - | $ - | $ - | -$ 695,136 | -$ 6,615,671 | -$ 1,132,441 | -$ 115,702 | $ - | $ - | -$ 1,248,143 |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | -$ 9,746,359 | $ 2,710,275 | -$ 1,312,515 | $ - | $ - | $ - | -$ 882,696 | -$ 6,606,265 | -$ 1,140,819 | -$ 115,649 | -$ 16,863 | $ - | -$ 1,239,605 |
| **RSVA - Power - Sub-account - Global Adjustment** | **1588** | $ 519,612 | $ 595,937 | $ 1,312,515 | $ - | $ - | $ - | $ 187,560 | -$ 9,406 | $ 8,378 | -$ 53 | $ 16,863 | $ - | -$ 8,538 |
| **Group 2 Accounts** | | | | | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - OEB Cost Assessments | 1508 | $ - | | | | | | | $ - | $ 946 | | | | $ 946 |
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | $ 387,334 | $ 132,179 | | | | | $ 131,342 | $ 650,855 | $ 1,098 | $ 6,603 | | | $ 7,701 |
| Retail Cost Variance Account - Retail | 1518 | $ 36,176 | $ 1,093 | | | | | -$ 10,172 | $ 27,097 | $ 575 | $ 523 | | | $ 1,098 |
| Misc. Deferred Debits | 1525 | $ - | | | | | | | $ - | $ 82 | | | | $ 82 |
| Renewable Generation Connection Capital Deferral Account | 1531 | $ 8,666 | | | | | | | $ 8,666 | $ - | $ 127 | | | $ 127 |
| Renewable Generation Connection OM&A Deferral Account | 1532 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Smart Grid Capital Deferral Account | 1534 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Smart Grid OM&A Deferral Account | 1535 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Smart Grid Funding Adder Deferral Account | 1536 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Retail Cost Variance Account - STR | 1548 | $ 235,596 | $ 13,507 | | | | | $ 17,263 | $ 266,366 | $ 48,608 | $ 3,559 | | | $ 52,167 |
| Board-Approved CDM Variance Account | 1567 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Extra-Ordinary Event Costs | 1572 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Deferred Rate Impact Amounts | 1574 | $ - | | | | | | | $ - | $ - | | | | $ - |
| RSVA - One-time | 1582 | $ 264,945 | | | | | | | $ 264,945 | $ 79,220 | $ 3,894 | | | $ 83,114 |
| Other Deferred Credits | 2425 | $ - | | | | | | | $ - | $ - | | | | $ - |
| **Group 2 Sub-Total** | | $ 932,717 | $ 146,779 | $ - | $ - | $ - | $ - | $ 138,433 | $ 1,217,929 | $ 130,529 | $ 14,706 | $ - | $ - | $ 145,235 |
| Deferred Payments in Lieu of Taxes | 1562 | -$ 5,218,693 | | | | | | 3,643,109.00 | -$ 1,575,584 | -$ 1,654,521 | -$ 76,715 | | $ 1,403,638 | -$ 327,598 |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | $ - | | | | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | -$ 36,700 | -$ 48,768 | | | | | -$ 46,435 | -$ 131,903 | $ - | -$ 810 | | | -$ 810 |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$ 13,549,423 | $ 3,404,223 | $ - | $ 3,643,109 | $ - | $ - | $ 3,039,971 | -$ 7,105,229 | -$ 2,656,433 | -$ 178,521 | $ - | $ 1,403,638 | -$ 1,431,316 |
| **Special Purpose Charge Assessment Variance Account[9]** | **1521** | $ 135,736 | -$ 117,952 | | | | | | $ 17,784 | $ 1,100 | $ 594 | | | $ 1,694 |
| **LRAM Variance Account** | **1568** | $ - | | | | | | | $ - | $ - | | | | $ - |
| **Total including Account 1521 and Account 1568** | | -$ 13,413,687 | $ 3,286,271 | $ - | $ 3,643,109 | $ - | $ - | $ 3,039,971 | -$ 7,087,445 | -$ 2,655,333 | -$ 177,927 | $ - | $ 1,403,638 | -$ 1,429,622 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11] | 1555 | $ 4,547,460 | $ 50,605 | | | | | | $ 4,598,065 | $ 28,883 | $ 70,301 | | | $ 99,184 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11] | 1555 | -$ 1,431,088 | -$ 938,002 | | | | | | -$ 2,369,090 | -$ 30,332 | -$ 27,329 | | | -$ 57,661 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11] | 1555 | $ - | | | | | | | $ - | $ - | | | | $ - |
| Smart Meter OM&A Variance[11] | 1556 | $ 401,508 | $ 366,579 | | | | | | $ 768,087 | $ 3,726 | $ 6,032 | | | $ 9,758 |
| **The following is not included in the total claim but are included on a memo basis:** | | | | | | | | | | | | | | |
| Deferred PILs Contra Account [5] | 1563 | $ 5,218,693 | | | | | | -$ 3,643,109 | $ 1,575,584 | $ 1,654,521 | $ 76,715 | | -$ 1,403,638 | $ 327,598 |
| IFRS-CGAAP Transition PP&E Amounts[10] | 1575 | $ - | | | | | | | $ - | $ - | | | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account | 1592 | $ 36,700 | $ 48,768 | | | | | $ 46,435 | $ 131,903 | $ - | $ 810 | | | $ 810 |
| Disposition and Recovery of Regulatory Balances[7] | 1595 | $ - | | | | | | | $ - | $ - | | | | $ - |

| | | 2012 | | | | Projected Interest on Dec-31-11 Balances | | | 2.1.7 RRR | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Account Descriptions** | **Account Number** | **Principal Disposition during 2012 - instructed by Board** | **Interest Disposition during 2012 - instructed by Board** | **Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012** | **Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012** | **Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]** | **Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]** | **Total Claim** | **As of Dec 31-11** | **Variance RRR vs. 2011 Balance *(Principal + Interest)*** |
| **Group 1 Accounts** | | | | | | | | | | |
| LV Variance Account | 1550 | | | $ - | $ - | | | $ - | | $ - |
| RSVA - Wholesale Market Service Charge | 1580 | -$ 1,063,709 | -$ 24,751 | -$ 2,407,015 | -$ 3,856 | -$ 30,182 | -$ 11,794 | -$ 2,452,847 | -$ 2,160,198 | $ 1,339,133 |
| RSVA - Retail Transmission Network Charge | 1584 | -$ 1,089,431 | -$ 24,222 | $ 177,629 | $ 2,934 | -$ 3,115 | $ 870 | $ 178,318 | -$ 1,126,125 | -$ 193,035 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$ 1,121,985 | -$ 24,485 | -$ 2,418 | -$ 1,050 | -$ 5,613 | -$ 12 | -$ 9,093 | -$ 1,252,286 | -$ 102,348 |
| RSVA - Power (excluding Global Adjustment) | 1588 | $ 337,568 | -$ 11,932 | -$ 1,772,558 | -$ 7,518 | -$ 11,734 | -$ 8,686 | -$ 1,800,496 | -$ 75,042 | $ 1,379,398 |
| RSVA - Power - Sub-account - Global Adjustment | 1588 | -$ 792,903 | -$ 24,026 | $ 783,497 | $ 15,488 | $ 7,089 | $ 3,839 | $ 809,913 | -$ 205,504 | -$ 187,560 |
| Recovery of Regulatory Asset Balances | 1590 | | | $ - | $ - | | | $ - | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2008)[7] | 1595 | | | $ - | $ - | | | $ - | | $ - |
| Disposition and Recovery/Refund of Regulatory Balances (2011)[7] | 1595 | | | $ 166,113 | -$ 27,008 | $ 612 | $ 528 | $ 140,245 | -$ 297,780 | -$ 436,885 |
| Disposition and Recovery/Refund of Regulatory Balances (2010)[7] | 1595 | | | $ 169,541 | -$ 1,117,717 | -$ 1,334 | $ 572 | -$ 948,938 | -$ 2,051,743 | -$ 1,103,567 |
| **Group 1 Sub-Total (including Account 1588 - Global Adjustment)** | | -$ 3,730,460 | -$ 109,416 | -$ 2,885,211 | -$ 1,138,727 | -$ 44,277 | -$ 14,683 | -$ 4,082,898 | -$ 7,168,678 | $ 695,136 |
| **Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)** | | -$ 2,937,557 | -$ 85,390 | -$ 3,668,708 | -$ 1,154,215 | -$ 51,366 | -$ 18,522 | -$ 4,892,811 | -$ 6,963,174 | $ 882,696 |
| **RSVA - Power - Sub-account - Global Adjustment** | **1588** | -$ 792,903 | -$ 24,026 | $ 783,497 | $ 15,488 | $ 7,089 | $ 3,839 | $ 809,913 | -$ 205,504 | -$ 187,560 |
| **Group 2 Accounts** | | | | | | | | | | |
| Other Regulatory Assets - Sub-Account - OEB Cost Assessments | 1508 | | | $ - | $ 946 | $ - | $ - | $ 946 | $ 946 | $ - |
| Other Regulatory Assets - Sub-Account - Pension Contributions | 1508 | | | $ - | $ - | | | $ - | | $ - |
| Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs | 1508 | | | $ - | $ - | | $ - | $ - | | $ - |
| Other Regulatory Assets - Sub-Account - Incremental Capital Charges | 1508 | | | $ - | $ - | | | $ - | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8] | 1508 | | | $ - | $ - | | | $ - | | $ - |
| Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges | 1508 | | | $ - | $ - | | | $ - | | $ - |
| Other Regulatory Assets - Sub-Account - Other [4] | 1508 | | | $ 650,855 | $ 7,701 | $ 8,512 | $ 3,189 | $ 670,257 | $ 527,214 | -$ 131,342 |
| Retail Cost Variance Account - Retail | 1518 | | | $ 27,097 | $ 1,098 | $ 474 | $ 133 | $ 28,802 | $ 38,367 | $ 10,172 |
| Misc. Deferred Debits | 1525 | | | $ - | $ 82 | $ - | $ - | $ 82 | $ 82 | $ - |
| Renewable Generation Connection Capital Deferral Account | 1531 | | | $ 8,666 | $ 127 | $ 127 | $ 42 | $ 8,962 | $ 8,793 | $ - |
| Renewable Generation Connection OM&A Deferral Account | 1532 | | | $ - | $ - | | | $ - | | $ - |
| Renewable Generation Connection Funding Adder Deferral Account | 1533 | | | $ - | $ - | | | $ - | | $ - |
| Smart Grid Capital Deferral Account | 1534 | | | $ - | $ - | | | $ - | | $ - |
| Smart Grid OM&A Deferral Account | 1535 | | | $ - | $ - | | | $ - | | $ - |
| Smart Grid Funding Adder Deferral Account | 1536 | | | $ - | $ - | | | $ - | | $ - |
| Retail Cost Variance Account - STR | 1548 | | | $ 266,366 | $ 52,167 | $ 3,791 | $ 1,305 | $ 323,629 | $ 301,270 | -$ 17,263 |
| Board-Approved CDM Variance Account | 1567 | | | $ - | $ - | | | $ - | | $ - |
| Extra-Ordinary Event Costs | 1572 | | | $ - | $ - | | | $ - | | $ - |
| Deferred Rate Impact Amounts | 1574 | | | $ - | $ - | | | $ - | | $ - |
| RSVA - One-time | 1582 | | | $ 264,945 | $ 83,114 | $ 3,895 | $ 1,298 | $ 353,252 | $ 348,059 | $ - |
| Other Deferred Credits | 2425 | | | $ - | $ - | | | $ - | | $ - |
| **Group 2 Sub-Total** | | $ - | $ - | $ 1,217,929 | $ 145,235 | $ 16,799 | $ 5,967 | $ 1,385,930 | $ 1,224,731 | -$ 138,433 |
| Deferred Payments in Lieu of Taxes | 1562 | -$ 1,575,584 | -$ 327,598 | $ - | $ - | | | $ - | -$ 1,903,182 | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below) | 1592 | | | $ - | $ - | | | $ - | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) | 1592 | | | -$ 131,903 | -$ 810 | -$ 1,563 | -$ 646 | -$ 134,922 | -$ 86,278 | $ 46,435 |
| | | | | | | | | | | $ - |
| **Total of Group 1 and Group 2 Accounts (including 1562 and 1592)** | | -$ 5,306,044 | -$ 437,014 | -$ 1,799,185 | -$ 994,302 | -$ 29,041 | -$ 9,362 | -$ 2,831,890 | -$ 7,933,407 | $ 603,138 |
| **Special Purpose Charge Assessment Variance Account[9]** | **1521** | $ 17,784 | $ 1,781 | $ - | -$ 87 | $ 87 | | $ - | $ 19,478 | $ - |
| | | | | | | | | | | $ - |
| **LRAM Variance Account** | **1568** | | | $ - | $ - | | | $ - | | $ - |
| **Total including Account 1521 and Account 1568** | | -$ 5,288,260 | -$ 435,233 | -$ 1,799,185 | -$ 994,389 | -$ 28,954 | -$ 9,362 | -$ 2,831,890 | -$ 7,913,929 | $ 603,138 |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11] | 1555 | | | $ 4,598,065 | $ 99,184 | | | $ 4,697,249 | $ 4,697,249 | $ - |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11] | 1555 | | | -$ 2,369,090 | -$ 57,661 | | | -$ 2,426,751 | -$ 2,426,751 | $ - |
| Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11] | 1555 | | | $ - | $ - | | | $ - | | $ - |
| Smart Meter OM&A Variance[11] | 1556 | | | $ 768,087 | $ 9,758 | | | $ 777,845 | $ 777,845 | $ - |
| **The following is not included in the total claim but are included on a memo basis:** | | | | | | | | | | |
| Deferred PILs Contra Account [5] | 1563 | -$ 92,597 | -$ 25,671 | $ 1,668,181 | $ 353,269 | | | $ 2,021,450 | $ 1,903,182 | $ - |
| IFRS-CGAAP Transition PP&E Amounts[10] | 1575 | | | $ - | $ - | | | $ - | | $ - |
| PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account | 1592 | | | $ 131,903 | $ 810 | | | $ 132,713 | $ 86,278 | -$ 46,435 |
| Disposition and Recovery of Regulatory Balances[7] | 1595 | $ 5,380,857 | $ 460,904 | -$ 5,380,857 | -$ 460,904 | | | -$ 5,841,761 | $ - | $ - |

## SMART METER PROPOSAL

BPI supported the province's Smart Metering Initiative ("SMI") through its Residential Smart Meter and GS<50 kW Smart Meter Deployment Programs (collectively this is referred to as BPI's "Smart Metering Integration Plan" or "SMIP").

BPI began installing smart meters in 2008 with the bulk of the installations taking place in 2010. In total, 34,927 residential and 2,748 General Service <50kW smart meters have been installed. All smart meters and related communications infrastructure were in keeping with the minimum functionality specified in O. Reg 425/06. Table 9.13 sets out the numbers of smart meters installed by customer type in each year from 2008 to 2012.

**Table 9.13: Actual Smart Meters Installed (2008 to 2012)**

| Actual Smart Meters Installed | 2008 Actual | 2009 Actual | 2010 Actual | 2011 Actual | 2012 Actual | Total |
|---|---|---|---|---|---|---|
| Residential | 293 | 6,331 | 27,735 | 458 | 110 | 34,927 |
| GS<50 kW | - | 204 | 1,057 | 1,380 | 107 | 2,748 |

Smart meters were not installed for General Service greater than 50 kW customers but where demand is greater than 200 kW, the threshold at which BPI requires interval meters. Installation of smart meters at those 267 customer connections would have been outside of the minimum functionality specifications and those customer accounts continue to be read using conventional meter reading technology. As well, smart meters have not yet been installed for 35 smart meter eligible customers. BPI continues its efforts to install smart meters at these locations.

The revenue requirement related to BPI's smart meter program is $2,388,514 less revenues received from the smart meter funding adder including interest of ($2,819,268) for a Net Deferred Revenue Requirement of ($430,755) please refer to Table 9.21. The capital cost the smart meter program is $5,373,737.

In order to minimize infrastructure and implementation costs pertaining to the implementation of its smart meter program, BPI participated with a consortium of 8 other utilities ("the smart metering consortium") on joint procurement activities and shares operational services with those utilities. Those utilities comprising the smart metering consortium include: Brant County Power, Norfolk, Haldimand Hydro, Grimsby Hydro, Niagara Peninsula Energy, Niagara-on-the-Lake, Canadian Niagara Power and Welland Hydro. By participating in this smart metering consortium, BPI also benefited from bulk purchasing activities.

While BPI owns the meters, towers and collectors that make-up its smart metering infrastructure, its service provider, Sensus, owns and operates the Advanced Metering Control Computer ("AMCC"). As well, BPI purchases operational data store services ("ODS") from Savage Data Systems on a fee for service basis.

- **Capital and Operating Costs for Smart Meters**

Table 9.14 below highlights BPI's actual smart meter capital and operating costs to December 31, 2012.

**Table 9.14: Smart Meter Capital and Operating Costs – 2006 to 2012**

| | 2006-2007 Capital | 2006-2007 Operating | 2008-2012 Capital | 2008-2012 Operating |
|---|---|---|---|---|
| Total | $ 25,571 | - | $ 5,348,166 | $ 272,199 |

The detailed breakdown of capital and operating costs is set out in the "Smart Meter Capital Cost and Operational Expense Data" worksheet of the smart meter model attached to this Exhibit as Appendix D. BPI notes that it has not incurred any capital or OM & A costs for capabilities that exceed minimum functionality.

The capital and operating cost components of BPI's smart metering program with references to the "Smart Meter Capital Cost and Operational Expense Data" worksheet are discussed in further detail below.

## Capital Costs – Advanced Metering Communications Device ("AMCD") – (1.1.)

BPI piggybacked on the outcomes of the London Hydro and Consortium of LDCs Smart Metering Project Request For Proposals ("the London RFP") for the selection of the Advanced Metering Infrastructure (the AMI). BPI contracted with the AMI technology provider identified in the RFP process as the best value vendor in the London RFP. The results of the smart metering consortium's RFP process were reviewed by the Fairness Commissioner and deemed to be in accordance with the principles set out in the London RFP. The Letter of Attestation by PRP International Inc. is included as Appendix C to this Exhibit.

**Table 9.15: AMCD Costs**

| | 2008 Audited Actual | 2009 Audited Actual | 2010 Audited Actual | 2011 Audited Actual | 2012 Forecast | 2013 Forecast | Total |
|---|---|---|---|---|---|---|---|
| Smart Meters (1.1.1) | $ 14,945 | $ 1,375,700 | $ 2,452,471 | $ 34,884 | $ 73,273 | - | $ 3,951,273 |
| Installation Costs (1.1.2) | - | $ 13,969 | $ 342,583 | $ 2,565 | - | - | $ 359,117 |
| Workforce Automation Hardware (1.1.3) | - | $ 39,852 | $ 2,086 | - | - | - | $ 41,938 |
| Workforce Automation Software | - | - | - | - | - | - | $ - |
| **Total OMCD** | $ 14,945 | $ 1,429,521 | $ 2,797,140 | $ 37,449 | $ 73,273 | - | $ 4,352,328 |

## Smart Meters – (1.1.1)

BPI participated in the smart metering consortium's joint purchase of smart meters selecting Sensus meters as compliant with the minimum functionality specifications. By purchasing smart metering devices through the consortium's bulk purchase RFP, BPI was able to take advantage of the large quantity discount that would not normally be available to a utility requiring less than 40,000 devices. BPI installed three types of smart meters. Sensus smart meters have been installed at residential accounts. For those General Service less than 50 kW accounts that required a meter socket different from the standard Sensus model and where Sensus did not provide an appropriate model of meter, either an Elster meter with a Sensus communications module or a GE meter with a Sensus communications module was installed. At the time of installation, both Elster and GE were the sole meter providers that could provide appropriate alternative meters with the Sensus communications module.

BPI's typical costs per type of smart meter are set out in Table 9.16 below. BPI notes that these costs have been used in the cost allocation model as smart meter installation costs.

**Table 9.16: Typical costs per type of smart meter installed**

| Type of Meter | Manufacturer | Cost Per Meter |
|---|---|---|
| Smart Meters - Single Phase | Sensus | $109 |
| Smart Meters – Network | Sensus | $211 |
| Smart Meters - three phase - no demand | Elster & GE | $700 |

**Installation Costs – (1.1.2)**

BPI also participated in the smart metering consortium's RFP for third-party services to install its residential smart meters including network meters. BPI contracted with Olameter, the meter installer identified in the RFP process as the best value vendor for the consortium and the scheduling of installation among the utilities in the consortium allowed for sharing of the third-party services. BPI metering forces installed commercial, institutional and polyphase commercial smart meters as well as subsequent residential meters installed after 2010. Miscellaneous installation costs include rental of temporary secured storage of meters prior to installation.

**Workforce Automation Hardware – (1.1.3)**

Workforce automation hardware, Fieldworker hand held units and peripheral devices, were acquired to track installation of smart meters in the field.

**Capital Costs – Advanced Metering Regional Collectors – (1.2)**

Advanced metering regional collection ("AMRC") costs pertain to the purchase and installation of the Sensus Collector tower centrally located within BPI's distribution service territory. (1.2.3)

### Table 9.17: AMRC Costs

| | 2008 Audited Actual | 2009 Audited Actual | 2010 Audited Actual | 2011 Audited Actual | 2012 Forecast | 2013 Forecast | Total |
|---|---|---|---|---|---|---|---|
| Collectors (1.2.3) | - | $ 184,684 | - | - | - | - | $ 184,684 |
| Installation (1.2.3) | - | $ 11,113 | $ 77,304 | $ 25,829 | - | $ 888 | $ 115,134 |
| **Total AMRC** | - | $ 195,797 | $ 77,304 | $ 25,829 | $ - | $ 888 | $ 299,818 |

## Capital Costs - Advanced Metering Control Computer – (1.3)

As discussed above, BPI through the smart metering consortium contracts for services with Sensus, a third-party vendor to provide and operate the Advanced Metering Control Computer. Through an RFP process, Sensus was determined to be the best value cost proponent. Under a services agreement, Sensus provides network, monitoring and security audit services on a fee for service basis. (1.3.2)

### Table 9.18: AMCC Costs

| | 2008 Audited Actual | 2009 Audited Actual | 2010 Audited Actual | 2011 Audited Actual | 2012 Forecast | 2013 Forecast | Total |
|---|---|---|---|---|---|---|---|
| Computer Software (1.3.2) | - | $ 106 | $ 78 | $ 1,780 | - | - | $ 1,964 |
| **Total AMCC** | - | $ 106 | $ 78 | $ 1,780 | - | - | $ 1,964 |

## Capital Costs – Other AMI Capital Costs related to Minimum Functionality (1.5)

Other AMI capital costs include professional fees, integration costs and program management costs.

### Table 9.19: AMI Capital Costs

| | 2006 Audited Actual | 2007 Audited Actual | 2008 Audited Actual | 2009 Audited Actual | 2010 Audited Actual | 2011 Audited Actual | 2012 Forecast | 2013 Forecast | Total |
|---|---|---|---|---|---|---|---|---|---|
| Professional Fees (1.5.3) | - | $ 12,763 | $ 19,371 | $ 22,381 | $ 25,177 | $ 9,542 | $ 12,367 | - | $ 101,601 |
| Integration (1.5.4) | - | - | - | $ 7,632 | $ 47,057 | $ 60,811 | - | - | $ 115,500 |
| Program Management (1.5.5) | $ 12,808 | - | - | $ 120,065 | $ 139,096 | $ 230,558 | - | - | $ 502,527 |
| **Total Other AMI Capital Costs Related to Minimum Functionality** | $ 12,808 | $ 12,763 | $ 19,371 | $ 150,078 | $ 211,330 | $ 300,911 | $ 12,367 | $ - | $ 719,628 |
| | | | | | | | | | |
| **Total Capital Costs Related to Minimum Functionality** | **$ 12,808** | **$ 12,763** | **$ 34,316** | **$ 1,775,503** | **$ 3,085,852** | **$ 365,968** | **$ 86,528** | **-** | **$ 5,373,738** |

**Professional Fees – (1.5.3)**

Professional fees comprise BPI's portion of fees paid to Util-Assist, a third-party service provider and shared among the smart metering consortium. In early 2010, BPI engaged the professional services of Util-Assist, an Ontario consulting firm specializing in metering solutions and technologies. In mid-2010, with Util-Assist's support, various preliminary project activities were undertaken. Most critically, assisting in the evaluation of the smart meter infrastructure responses to the London RFP, the processing of Requests for Proposal for mass installation of residential smart meters and the supply and support of a meter data operational data store (ODS) for the Sensus metering system were issued and evaluated culminating in the selection of successful vendors. Util-Assist remained actively involved in the implementation and roll-out phases of the mass deployment contract and WAN implementation, as well as ODS contract negotiation through to the end of 2010 and into Q1 and Q2 2011. Util-Assist's services to BPI were expanded in 2011 to include project management assistance and training services related to BPI's internal preparations and readiness for MDM/R enrolment.

Legal fees for third-party law firms, each engaged as a result of competitive bidding processes, to review various smart meter related agreements are also included in professional fees.

**Integration – (1.5.4)**

Integration costs pertain to costs for the ODS, a function that has been outsourced to a third-party on a service bureau basis. Costs were capitalized up to 2012. BPI participated in the smart metering consortium RFP process for the supply and operation of an ODS and BPI contracted Savage, the best value vendor identified in the RFP process.

**Program Management – (1.5.5)**

Program management costs from 2006 to 2011 pertain to the costs of BPI staff, specifically the then Manager of Metering and Settlement and a Settlement Energy and Smart Metering Officer ("SESMO"), whose time was allocated to the smart meter implementation project for incremental activities required by the project. The Manager was responsible for the overall management of the smart metering project. The SESMO position was responsible for the daily smart meter data issues including, as examples, AMI system health, smart meter VEE, review of and response to the smart meter system generated reports of quarantine, trouble, tamper, over/under voltage.

In addition to internal staff resources, BPI engaged 2 additional resources on a contract basis. The Workforce Management coordinator was engaged for 6 months in 2010 to oversee the installation of residential smart meters. The IT Utility Project Manager was engaged for 15 months from August 2010 to October 2011 to oversee the integration of IT systems to allow time-of-use billing and implementation of new business processes.

**OM&A Expenses**

Maintenance costs related to Advanced Metering Communication devices pertain primarily to repairs to meter bases. (2.1.1)

Maintenance costs for the Advanced Metering Regional Collector in 2011 and 2012 pertain to maintenance fees paid to Sensus and in 2012 for the ODS service fees, which had been capitalized prior to 2012. (2.2.1) Other Program Management costs pertain to BPI staff time allocated to the smart meter project, which had been capitalized prior to 2012. (2.5.3)

## Table 9.20: OM&A Costs

| | 2008 Audited Actual | 2009 Audited Actual | 2010 Audited Actual | 2011 Audited Actual | 2012 Forecast | 2013 Forecast | Total |
|---|---|---|---|---|---|---|---|
| Incremental AMCD OM&A Costs | | | | | | | |
| Maintenance (2.1.1) | - | $ 2,468 | $ 22,585 | $ 695 | - | - | $ 25,748 |
| **Total Incremental AMCD OM&A Costs** | **-** | **$ 2,468** | **$ 22,585** | **$ 695** | **-** | **-** | **$ 25,748** |
| Advanced Metering Regional Collector (AMRC) (includes LAN) | | | | | | | |
| Maintenance (2.2.1) | - | $ - | - | $ 26,601.0 | $ 139,030.0 | $ 42,000.0 | $ 207,631 |
| **Total Incremental AMRC OM&A Costs** | **-** | **$ -** | **$ -** | **$ 26,601.0** | **$ 139,030.0** | **$ 42,000.0** | **$ 207,631** |
| Other AMI OM&A Costs related to Minimum Functionality | | | | | | | |
| Program Management (2.5.3) | | $ 2,674 | - | $ 23,920 | 54,227.00 | - | $ 80,821 |
| **Total Other AMI OM&A Costs Related to Minimum Functionality** | | **$ 2,674** | **-** | **$ 23,920** | **$ 54,227** | **-** | **$ 80,821** |
| **Total OM&A Costs** | | **$ 5,142** | **$ 22,585** | **$ 51,216** | **$ 193,257** | **$ 42,000** | **$ 314,200** |

## Time-of-Use Billing

BPI's preparation for time-of-use ("TOU") pricing was part of the provincial plan to create a culture of conservation in Ontario that began in 2008. TOU provides an incentive for customers to shift and/or reduce electricity consumption at times of peak demand. BPI began collecting the data needed to implement TOU pricing from residential and most GS<50 kW customers on November 1, 2011. A communication package sent out in October 2011 helped to prepare customers for this transition. BPI customers were billed using TOU pricing on bills received after December 15, 2011, the culmination of a three-year transition process.

## Smart Meters Recovery – Smart Meter Disposition Rate Rider

In accordance with the Board's Guideline G-2011-0001 *Smart Meter Funding and Cost Recovery – Final Disposition*, BPI is seeking approval of smart meter costs described above and included in the 2013 Smart Meter Model provided by the Board to calculate the Smart Meter Disposition Rider attached as Appendix D to this Exhibit.

As described in the table below $(430,755) is the amount to be disposed and is the difference between revenue related to the smart meter costs and the corresponding smart meter funding adders were collected by BPI from May 1, 2006 to December 31, 2012.

**Table 9.21: Disposition of Smart Meter Costs**

| | |
|---|---|
| Smart Meter Revenue Requirement | $ 2,388,514 |
| Interest on OM&A and Amortization Expense | - |
| | $ 2,388,514 |
| Smart Meter Funding Adder | $ (2,683,669) |
| Interest on Smart Meter Funding Adder | $ (135,599) |
| Net Deferred Revenue Requirement to be disposed | $ (430,755) |
| Allocation of ($430,755) between customers | |
| Residential | $ (328,359) |
| GS<50 kW | $ (102,396) |
| | $ (430,755) |
| Average number of customers (2013) | |
| Residential | 35,364 |
| GS<50 kW | 2,764 |
| | 38,128 |
| Smart Meter Disposition Rate Rider - 1 Year | |
| Residential | $ (0.77) |
| GS<50 kW | $ (3.09) |
| Proposed Smart Meter Disposition Rate Rider - 4 Years | |
| Residential | **$ (0.19)** |
| GS<50 kW | **$ (0.77)** |

Based on BPI's 2013 forecast of metered residential and GS<50 kW customers a rate rider of $(0.77) per month for residential class and $(3.09) per month for GS<50 kW class would be required to dispose of this amount in one year starting January 1, 2014. To reduce the impact to BPI customers, BPI proposes to dispose of this amount over 4 years at a monthly rate rider of $(0.19) for residential class and $(0.77) for GS<50 kW class. These rate riders would only apply to residential and GS<50 kW customers. The disposition period is consistent with the recovery period proposed below for stranded meters.

# APPENDIX C

# FAIRNESS COMMISSIONER ATTESTATION

# PRP International, Inc.

*Fairness Advisory Services*

August 1, 2008

Mr. George Mychailenko
President
Brantford Power Inc.
84 Market Street, P.O. Box 308
Brantford, ON N3T 5N8

Dear Mr. Mychailenko:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August-July 2008
London Hydro, Consortium & Add-On LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Add-On LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

*"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the* ***NEPA Collective of LDCs (Brant County Power Inc., Brantford Power Inc., Canadian Niagara Power Inc. (Fortis), Grimsby Power Incorporated, Haldimand County Hydro Inc., Niagara-on-the-Lake Hydro Inc., Niagara Peninsula Energy Inc., Norfolk Power Distribution Inc., and Welland Hydro Electric System Corp.)*** *requirements are:*

- *KTI/Sensus Limited, as the recommended Preferred Proponent, based on its highest ranking, and*
- *Elster Metering being the second ranked Proponent.*

*These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."*

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen
President
cc: Mr. Gary Rains, RFP Project Director

203 - 8 QUEEN STREET, SUMMERSIDE, PEI C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

# APPENDIX D

# SMART METER MODEL

Class-specific SMDRs

| **Revenue Requirement for Historical Years** | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | Total 2006 to 2012 | **Explanation / Allocator** | Residential | GS < 50 kW | GS 50 to 4999 kW | Other (please specify) | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Check Row if SMDR/SMIRR apply to class | X | X | | | 2 |
| | | | | | | | | | | % | % | % | % | |
| | | | | | | | | | Weighted Meter Cost - Capital | 73.86% | 26.14% | | | 100% |
| Return on Capital | $ 446.20 | $ 1,306.29 | $ 2,780.93 | $ 68,542.40 | $ 233,624.84 | $ 320,454.26 | $ 313,125.70 | $ 940,280.63 | Allocated per class | $ 694,524.59 | $ 245,756.03 | $ - | $ - | |
| Depreciation/Amortization | $ 426.92 | $ 1,279.29 | $ 2,848.61 | $ 65,839.76 | $ 230,693.04 | $ 346,016.63 | $ 361,218.48 | | | | | | | |
| expense and related interest | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | Weighted Meter Cost - Capital | 74% | 26% | 0% | 0% | 100% |
| | $ 426.92 | $ 1,279.29 | $ 2,848.61 | $ 65,839.76 | $ 230,693.04 | $ 346,016.63 | $ 361,218.48 | $ 1,008,322.73 | Allocated per class | $ 744,782.90 | $ 263,539.83 | $ - | $ - | |
| Operating Expenses and related interest | $ - | $ - | $ - | $ 5,142.38 | $ 22,584.93 | $ 51,215.29 | $ 193,256.35 | | Number of Smart Meters installed by Class | # | # | # | # | |
| | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | 35,556 | 2,749 | | | |
| | $ - | $ - | $ - | $ 5,142.38 | $ 22,584.93 | $ 51,215.29 | $ 193,256.35 | $ 272,198.95 | Allocated per class | $ 252,667.06 | $ 19,531.89 | 0 | 0 | |
| Revenue Requirement before Taxes/PILs | | | | | | | | $ 2,220,802.30 | | $ 1,691,974.55 | $ 528,827.75 | $ - | $ - | $ - |
| | | | | | | | | | Revenue Requirement before PILs | 76.19% | 23.81% | 0.00% | 0.00% | 100% |
| Grossed-up Taxes/PILs | $ 127.47 | $ 337.99 | $ 602.18 | $ 11,477.91 | $ 41,852.32 | $ 54,360.59 | $ 58,953.00 | $ 167,711.45 | | $ 127,775.23 | $ 39,936.23 | $ - | $ - | |
| Total Revenue Requirement plus interest on OM&A and depreciation expense | | | | | | | | $ 2,388,513.76 | | $ 1,819,749.78 | $ 568,763.98 | $ - | $ - | |
| | | | | | | | | | Percentage of costs allocated to each cla | 76.19% | 23.81% | 0.00% | 0.00% | |
| | | | | | | | | $ - | Percentage of costs for classes with | 76.19% | 23.81% | 0.00% | 0.00% | |
| | | | | | | | | | SMDR/SMIRR | 76.19% | 23.81% | 0.00% | 0.00% | |
| | | | | | | | | | | % | % | % | % | |
| | | | | | | | SMFA Revenues directly attributable to class | | | 76.19% | 23.81% | | | 100% |
| | | | | | | | | | | 76.19% | 23.81% | 0.00% | 0.00% | 100.00% |
| | | | | | | | Residual SMFA Revenues (from other metered classes) attributed evenly | | | 0.00% | 0.00% | 0.00% | 0.00% | |
| | | | | | | | Total | | | 76.19% | 23.81% | 0.00% | 0.00% | |
| SMFA Revenues plus interest expense | | | | | | | | $ 2,819,268.43 | | $ 2,147,931.15 | $ 671,337.28 | $ - | $ - | |
| Net Deferred Revenue Requirement to be recovered via SMDR | | | | | | | | -$ 430,754.67 | | -$ 328,181.37 | -$ 102,573.30 | $ - | $ - | |
| Average number of metered customers by class (2013) | | | | | | | | Average number of customers (2013) | | 35,556 | 2,780 | 0 | 0 | |
| Number of Years for SMDR recovery | | | | | | | | 1 years | | 1 | 1 | 1 | 1 | |
| Smart Meter Disposition Rider ($/month per metered customer in the customer class) | | | | | | | | | | -$ 0.77 | -$ 3.08 | | | |
| Estimated SMDR Revenues | | | | | | | | -$ 431,268.27 | | -$ 328,535.55 | -$ 102,732.72 | $ - | $ - | |
| | | | | | | | | $ 513.60 | | | | | | |

## STRANDED METER PROPOSAL

In accordance with the Board’s Guideline G-2011-0001 *Smart Meter Funding and Cost Recovery – Final Disposition*, it was determined that the net book value of meters stranded due to the installation of smart meters should be removed from rate base. The removed amount would be allowed for recovery by means of separate rate riders for the applicable customer classes, rather than by leaving the stranded assets in Rate Base. BPI is also seeking disposition of its stranded meter costs with this application.

BPI continued to record the costs of the stranded meters in Account 1860 and depreciated these assets over a 25-year period. In 2012, BPI removed stranded meters from Account 1860 less Accumulated Amortization and proceeds on disposal of conventional meters; offset of this transaction was done in Account 1555 Capital and Recovery Offset.

Had BPI chosen the alternative accounting treatment for stranded meters to remain in Account 1860, the same residual net book value of $3,237,191 at December 31, 2012 would have resulted.

Table 9.22 below contains the residual net book value of stranded meters being the gross asset value less the accumulated amortization and proceeds on the disposal of scrapped meters and accumulated depreciation balance.

**Table 9.22: Stranded Asset Values**

| Year | Gross Asset Value | Accumulated Amortization | Contributed Capital | Net Asset | Proceeds on Disposal | Residual Net Book Value |
|---|---|---|---|---|---|---|
| **2006** | | | | $ - | | $ - |
| **2007** | | | | $ - | | $ - |
| **2008** | | | | $ - | | $ - |
| **2009** | $ 953,530 | $ (359,800) | | $ 593,730 | | $ 593,730 |
| **2010** | $ 3,978,550 | $ (1,521,728) | | $ 2,456,822 | $ (3,781) | $ 2,453,041 |
| **2011** | $ 342,720 | $ (150,854) | | $ 191,866 | $ (1,446) | $ 190,420 |
| **2012** | | | | $ - | | $ - |
| | $ 5,274,800 | $ (2,032,381) | $ - | $ 3,242,419 | $ (5,228) | $ 3,237,191 |

- **Disposition of Stranded Meter Costs**

BPI is requesting recovery of the $3,237,191 in residual net book value of the assets. BPI is adhering to section 2.5.1.5 Treatment of Stranded Assets Related to Smart Meter Deployment in the Board's June 28, 2012 Chapter 2 Filing Requirements for Transmission and Distribution Applications. BPI removed stranded meters totaling $3,237,191 from account 1860; offset of this transaction was done in account 1555 (Smart Meters Recovery). BPI requests to recover this amount through a fixed monthly rider from metered residential and GS<50 kW customers.

Based on BPI's 2013 customer forecast, a rate rider of $7.08 per month for the Residential class and $7.00 per month for the GS<50 kW class would be required to recover these amounts in one year starting January 1, 2014. To reduce customer impact, BPI proposes to recover this amount over 4 years at a monthly rate of $1.77 for the Residential class and $1.75 for the GS<50 kW class. These rate riders would only apply to Residential and GS<50 kW customers as only these customer classes' meters were stranded as part of the deployment program. Table 9.23 shows the proposed stranded meter rate rider by customer class.

**Table 9.23: Stranded Meters Rate Riders by Customer Classes**

| | Residential | GS < 50 kW | Total |
|---|---|---|---|
| Smart Meters Installed at May 1, 2012 | 34,927 | 2,748 | 37,675 |
| Smart Meters Installed as a percentage | 92.7% | 7.3% | 100% |
| | | | |
| Stranded Asset Balance to be Recovered | $ 3,005,106 | $ 232,085 | $ 3,237,191 |
| Number of Customers - 2013 Forecast | 35,364 | 2,764 | 38,128 |
| | | | |
| Rate Rider - 1 Year | $ 7.08 | $ 7.00 | |
| **Proposed Rate Rider - 4years** | **$ 1.77** | **$ 1.75** | |

## Green Energy Plan – Funding Adder

BPI has submitted a Basic Green Energy Plan to the OPA and has provided a copy in Exhibit 2, Appendix E. The OPA provided a Letter of Comment, which has been provided in Exhibit 2, Appendix F. As indicated in that plan, BPI has determined that it does not anticipate any capital or OM&A spending for Basic Green Energy Plan purposes.