OVERVIEW

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2013 Test Year, plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The BPI rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

BPI has provided its rate base calculations for the years 2008 Actual, 2008 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year in Table 2.1 below. BPI has calculated its 2013 rate base as $78,748,369 under Modified CGAAP which will be used to determine the proposed revenue requirement.

Table 2.1 – Summary of Rate Base – 2013 CGAAP

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Average Net Book Value	$ 57,505,800	$ 57,342,802	$ 59,098,860	$ 60,935,057	$ 62,191,372	$ 61,363,461	$ 64,807,318
Working Capital Allowance*	$ 12,096,131	$ 12,295,065	$ 11,987,350	$ 12,779,357	$ 13,404,151	$ 14,651,709	$ 13,941,051
Rate Base	$ 69,601,931	$ 69,637,867	$ 71,086,210	$ 73,714,414	$ 75,595,523	$ 76,015,169	$ 78,748,369
*15% (2008-2012) & 13% (2013)							

This exhibit will compare historical data with the 2012 Bridge Year and 2013 Test Year under Modified CGAAP.

The BPI Distribution System:

BPI owns and operates the electricity distribution system in the City of Brantford serving more than 38,500 residential and business customers.

BPI supplies electricity to its customers in the City of Brantford through three High-Voltage Transformer Stations (TS) via mainly overhead primary circuits at 27.6kV. Two of these, Brant TS and Brantford TS are owned by Hydro One Networks Inc. (HONI) whereas the third, Powerline Municipal Transformer Station (PMTS) is jointly owned by BPI with Brant County Power Inc. (BCPI);

Apart from supplying customers within its own territory, BPI also delivers electricity to BCPI which is an embedded distributor to BPI. BCPI receives electricity from metered locations on three BPI distribution feeders.

BPI's licensed service area is 74 square kilometres, and is fully occupied by urban service area. BPI's distribution system is made up of:

Poles	10,112
Distribution Transformers	3,254
Distribution and Transmission Stations	1 (BPI owns 5/8 and BCPI owns 3/8 of PMTS)
Km of Overhead Line	274
Km of Underground Line	238.

In managing its distribution system assets, BPI's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public and worker safety and customer service expectations. This Application incorporates BPI's 2013 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

BPI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, system configuration, line loss reduction and outage mitigation to determine investment needs in the system.

Beginning in 2013, BPI incorporated outputs from its Asset Management Program ("AMP"), discussed in greater detail in Exhibit 2, Appendix C-2 that has been in development since 2010 to inform the capital budget process. As part of the AMP, BPI reviews capital projects identified for potential implementation and prioritizes each project based on defined criteria. Six Risk Criteria are used to assess assets and determine Consequence of Failure levels as laid out in the Corporate Risk Policy (considered and approved by the Board of Directors). These criteria are:

- Health and Safety
- External Demands
- Operational
- Environmental
- Financial
- Political and Regulatory.

The BPI management team follows outputs from the AMP and outlines their recommendations, which are then discussed by the full management team. After examining all recommended projects, each are listed in order from high to low priority and then moved forward based on as an "as-needed" basis. Various studies and assessments of BPI assets are used to assess the condition of assets and identify project priorities. For example BPI has a pole testing and treatment program, which reports the condition of poles with specific reference to "priority poles" which have been identified as poles reaching the end of their useful lives and requiring priority replacement. BPI uses this database of pole location, type, age, and test results to provide a basis for long-range pole replacement plans. In addition, priorities may be affected by outside requirements as with an obligation to relocate a pole line to accommodate a municipal or provincial road widening and relocation.

Substation assets are similarly evaluated as to condition and priority upgrades are identified and scheduled to maintain substation reliability and safety.

In addition to the capital needs of the network, BPI provides and plans for system maintenance of the network on a priority basis. The same preparation and consideration steps are undertaken before the final recommended budget amounts are established. Further information on BPI's Capital, Operations and Maintenance and Administration amounts will follow later in this Application.

Capital Asset Categories

BPI's assets fall into two broad categories – The first is ***distribution plant***, which includes assets such as high voltage transformation, PMTS, land and buildings, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and equipment. The second is ***general plant*** which includes assets such as: office furniture, transportation equipment, communications technology, computer equipment and software, general equipment and tools. A more detailed list of distribution and general plant categories can be found in Table 2.15 (Gross Assets) in Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects:

BPI projects may be the result of a variety of factors. BPI's capital budget items include projects to accommodate:

- **Customer Demand:**

These are projects that BPI undertakes to meet its customer service obligations in accordance with the Board's *Distribution System Code* (the "DSC") and BPI's *Conditions of Service*. Activities include connecting new customers and building or overseeing construction of distribution systems for new subdivisions. Capital contributions toward the cost of these projects are collected by BPI in accordance with the provisions of its *Conditions of Service*.

- **Renewal:**

Renewal projects are completed when assets reach the end of their useful lives and must be replaced. BPI completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public. Starting in 2013, renewal projects are subject to the Asset Management Program.

- **Security:**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup supply (i.e. feeder or TS transformer etc.) to reduce the risk of power outages and to reduce restoration times.

- **Capacity:**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects, substations or transformer stations additions or upgrades. These non-discretionary projects benefit many customers.

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve BPI reliability performance as measured by: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). These measures are indicators of the reliability of BPI's distribution system. These activities will support maintenance of, or improvement to, the Service Quality Indices measured and submitted to the Board each year by BPI. The AMP provided in

Exhibit 2, Tab 3, Schedule 5 supports the capital and maintenance programs needed to maintain and enhance the reliability of BPI's distribution system.

- **Regulatory and External Requirements:**

These projects are non-discretionary system capital investments, which are being driven by regulatory and external requirements. These requirements may include, among others, directions from the Board, the IESO, the Ministry of Energy or the Ministry of Environment and the City of Brantford. Regulatory requirement projects can also include relocating system plant for roadway reconstruction work. Where road widening projects are required as a result of municipal infrastructure development, BPI follows the *Public Service Works on Highways Act, 1990* and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of BPI labour and vehicles.

- **Transformer Stations:**

BPI is served by two transformer stations owned by HONI and a third station jointly owned by BPI and BCPI. Transformer Stations are used to transfer power from the transmission system at 115 and/or 230 kV voltage levels to the distribution system at BPI's standard 27.6 kV. Investments are undertaken to improve or maintain reliability to a large number of customers, maintain security and safety at the transformer stations, and to meet long range load growth. The Station facilities include power transformers, circuit breakers, switchgear, bus, insulators, power cables, support structures, disconnect switches and ancillary equipment.

- **Substations:**

Distribution substations (DS) are used to transfer power received from the transformer stations via primary distribution feeders to either 8.32 kV or 4.16 kV for further distribution. In 2009, BPI completed a multi-year program to upgrade its system from 4 and/8 kV levels to a 27.6 kV system with the result that all distribution stations have been retired.

- **Metering for new Customer Connections:**

Capital expenditures in this pool include new customer meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities; these capital expenditures were booked to Account 1860.

In 2010 BPI began installation of smart meters and completed the program in 2012. Smart meter activity and related expenses are discussed in full in Exhibit 9.

BPI capital projects for the 2013 Test Year are discussed in further detail in Exhibit 2, Tab 3, Schedule 2. BPI has provided project-specific justifications for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year.

Gross Assets – Property, Plant and Equipment and Accumulated Amortization:

The 2012 Bridge and 2013 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. Analyses of 2008 to 2013 capital programs are described in detail in BPI's written evidence at Exhibit 2, Tab 2, Schedule 3.

Budget Process:

BPI's AMP, which sets out processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers, accompanies this Exhibit as Appendix B-2. A detailed explanation of BPI's Asset Management is discussed in section below pertaining to BPI's developing Asset Management Program.

The budget is prepared annually by management and is reviewed and approved by the BPI Board of Directors. The budget is prepared before the start of each fiscal year.

For a full description of BPI's budget process please refer to Exhibit 1, Tab 2, Schedule 2.

VARIANCE ANALYSIS OF RATE BASE

The following section shows BPI's year over year variance analysis to rate base and also highlights factors that caused them.

Table 2.2: 2008 Approved Rate Base vs. 2008 Actual Rate Base

Description	2008 Board Approved	2008 Actual	Variance
Gross Fixed Assets	78,967,586	78,236,661	(730,925)
Accumulated Depreciation	20,241,853	19,952,643	(289,210)
Net Book Value	58,725,733	58,284,018	(441,715)
Average Net Book Value	57,505,800	57,342,802	(162,998)
Working Capital	80,640,872	81,967,102	1,326,230
Working Capital Allowance	12,096,131	12,295,065	198,934
Rate Base	69,601,931	69,637,867	35,937

The 2008 actual rate base was a variance of $35,937 or 0.05% higher than approved by the Board and is below the Materiality threshold.

Table 2.3: 2008 Actual vs. 2009 Actual

Description	2008 Actual	2009 Actual	Variance
Gross Fixed Assets	78,236,661	83,188,424	4,951,763
Accumulated Depreciation	19,952,643	23,274,722	3,322,079
Net Book Value	58,284,018	59,913,702	1,629,684
Average Net Book Value	57,342,802	59,098,860	1,756,058
Working Capital	81,967,102	79,915,669	(2,051,433)
Working Capital Allowance (15%)	12,295,065	11,987,350	(307,715)
Rate Base	69,637,867	71,086,210	1,448,343

The 2009 actual rate base was $1,448,343 or 2% higher than 2008 Actual. This increase is the result of the following factors. Each capital project is assigned a reference number which is used later on in the evidence, explained in Capital Projects by Year and USoA.

1. Increased rate base investments resulting from two large scale projects in 2009: Wynfield West extension of Blackburn expansion (capital project #7) and the conversion of lines at

Tranquility, Rosewood, Wyndham Hills, Ava Road, Sixth Avenue and Strawberry Hill (capital project #9).

Table 2.4: 2009 Actual vs. 2010 Actual

Description	2009 Actual	2010 Actual	Variance
Gross Fixed Assets	83,188,424	88,665,431	5,477,006
Accumulated Depreciation	23,274,722	26,709,019	3,434,296
Net Book Value	59,913,702	61,956,412	2,042,710
Average Net Book Value	59,098,860	60,935,057	1,836,197
Working Capital	79,915,669	85,195,713	5,280,044
Working Capital Allowance (15%)	11,987,350	12,779,357	792,007
Rate Base	71,086,210	73,714,414	2,628,204

The rate base of $73,714,414 for 2010 represented an increase of $2,628,204, or 3.7% over 2009 Actual. This increase is primarily the result of an increase in average net fixed assets due to capital expenditures.

This increase is the result of the following factors:

1. Increased rate base investments resulting from normal capital upgrades and expansions including voltage conversion projects in 2010 such as upgrading feeders on the Powerline Municipal Transformer Station (capital project #5) and Brantwood Park (capital project #9). In addition to these projects, a major SCADA software/hardware upgrade was performed (from a Virtual Memory System to a Windows platform) (capital project #7).
2. Working capital allowance increased by a total of $792,007; the main driver of this was an increase in commodity cost.
3. Normal inflationary increases.

Table 2.5: 2010 Actual vs. 2011 Actual

Description	2010 Actual	2011 Actual	Variance
Gross Fixed Assets	88,665,431	92,645,518	3,980,087
Accumulated Depreciation	26,709,019	30,219,185	3,510,166
Net Book Value	61,956,412	62,426,332	469,920
Average Net Book Value	60,935,057	62,191,372	1,256,315
Working Capital	85,195,713	89,361,008	4,165,295
Working Capital Allowance (15%)	12,779,357	13,404,151	624,794
Rate Base	73,714,414	75,595,523	1,881,110

The total rate base was $1,881,110 or 2.6% higher from 2010 as a result of the following factors:

1. Increased rate base investments in 2011 due to the rebuild of the Brantwood/Dundson area (capital project #9) and more investment in general yearly rebuilds (capital project #8).
2. Normal inflationary increases.
3. Working capital allowance increased by a total of $624,794; the main driver of this was an increase in commodity cost.

Table 2.6: 2011 vs. 2012 Bridge Year

Description	2011 Actual	2012 Bridge Year	Variance
Gross Fixed Assets	92,645,518	92,527,660	(117,857)
Accumulated Depreciation	30,219,185	32,227,071	2,007,886
Net Book Value	62,426,332	60,300,589	(2,125,744)
Average Net Book Value	62,191,372	61,363,461	(827,912)
Working Capital	89,361,008	97,678,058	8,317,050
Working Capital Allowance (15%)	13,404,151	14,651,709	1,247,558
Rate Base	75,595,523	76,015,169	419,646

The total rate base was $419,646 or 0.5% higher from 2011 as a result of the following factors:

1. Increased rate base investments in 2012 resulting from normal capital upgraded and expansions such as the Lynden Hills Estates (capital project #9) and Wynfield West – Stage 2 (capital project #7).
2. Normal inflationary increases.
3. Working capital allowance increased by a total of $1,247,558; the main driver of this was an increase in commodity cost.
4. BPI's conventional meters that were stranded by conversion to smart meters were reflected in BPI's rate base. Below is a detailed explanation on how they have affected BPI's rate base:

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. BPI seeks disposition of its stranded meter costs as at December 31, 2012. Historical stranded conventional meter gross asset values and net book values are shown in Table 2.7 below.

Table 2.7: Residual Net Book Value of Stranded Meters

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

BPI has followed stranded meter accounting treatment in accordance with *Guideline G-2011-0001*, whereby the stranded meters are recorded in Account 1555 Capital and Recovery Offset. As described in the Combined Smart Meter Proceeding (EB-2007-0063) the allocation of stranded meters to Account 1555 is based on the estimated average net book value of the conventional meters that became stranded during the year. BPI's net book value of stranded meters at December 31, 2012 is $3,242,419, which includes the reduction for accumulated amortization occurring after the meters were removed from service. After deducting the proceeds on disposition from the sale of scrap materials totaling $5,228, the residual net book value amount of stranded meters requested for disposition at December 31, 2012 is $3,237,191.

In summary, in 2012 BPI removed stranded meters from account 1860 and the offset of this transaction was done in account 1555. This amounting treatment involved moving $5,274,800 stranded meter gross asset value, less $2,032,381 in accumulated amortization and less $5,228 proceeds from the sale of scrap maters for a total amount of $3,237,191. Details of disposition and allocation of stranded meter costs are found in Exhibit 9 Tab 5 Schedule 4.

Table 2.8: 2012 vs. 2013 Test Year (CGAAP)

Description	2012 Bridge Year	2013 Test Year	Variance
Gross Fixed Assets	92,527,660	101,341,558	8,813,897
Accumulated Depreciation	32,227,071	36,392,925	4,165,853
Net Book Value	60,300,589	64,948,633	4,648,044
Average Net Book Value	61,363,461	64,807,318	3,443,857
Working Capital	97,678,058	107,238,853	9,560,795
Working Capital Allowance: 15% (2012) & 13% (2013)	14,651,709	13,941,051	(710,658)
Rate Base	76,015,169	78,748,369	2,733,200

The increase in rate base is the result of bringing smart meters into rate base as described below:

In 2013 $5,373,737 of smart meter costs and $1,008,323 of accumulated amortization with an ending net book value of $4,365,414 was brought into BPI's rate base in accordance with the Board's Guideline G-2011-0001 *Smart Meter Funding and Cost Recovery – Final Disposition.*

Accounting treatment of smart meter costs involved moving the following 2013 opening balances from tab 4 (smart meter assets and rate base) of the smart meter model; $5,329,836 of smart meter costs to account 1860, $41,938 of computer hardware costs to account 1920 and $1,963 of computer software gross book value to account 1925 resulting in a total of $5,373,737 of smart meter costs.

Accumulated amortization accounting treatment also involved the same above accounts as smart meter costs and involved moving the following accumulation amortization expenses; $978,736 was moved to account 1860, $28,940 to account 1920 and $647 to account 1925 resulting in a total of $1,008,323 of accumulated amortization.

BPI's smart meter revenue requirement is $2,388,514 and includes interest on OM&A and amortization expense. After deducting the revenues from smart meter funding adder in the amount of $(2,683,669) and interest on smart meter funding adder totaling $(135,599), the net deferred revenue requirement requested for disposition is $(430,755).

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 and details of disposition and allocation of smart meter costs are found in Exhibit 9 Tab 4 Schedule 1.

GROSS ASSETS – PROPERTY, PLANT and EQUIPMENT and ACCUMULATED AMORTIZATION:

Given that BPI will not be converting to IFRS in 2013, it is providing a continuity schedule for 2013 based on CGAAP modified for the change in capitalization and depreciation.

Table 2.9: Fixed Asset Continuity Schedule – 2008

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2008**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)					$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 208,241	-$ 20,312	$ -	$ 187,929	$ -	$ -	$ -	$ -	$ 187,929
CEC	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1808	Buildings		$ 1,192,568	-$ 28,837	$ -	$ 1,163,732	-$ 82,210	-$ 23,274	$ 4,048	-$ 101,436	$ 1,062,296
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541	$ -	$ -	$ 4,469,541	-$ 332,907	-$ 111,739	$ -	-$ 444,646	$ 4,024,895
47	1820	Distribution Station Equipment <50 kV		$ 140,683	-$ 66,256	$ -	$ 74,427	-$ 33,449	-$ 2,480	$ 15,828	-$ 20,101	$ 54,326
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 13,076,251	$ 610,799	$ -	$ 13,687,050	-$ 3,383,375	-$ 547,481	$ -	-$ 3,930,856	$ 9,756,194
47	1835	Overhead Conductors & Devices		$ 9,890,796	$ 570,913	$ -	$ 10,461,708	-$ 2,069,539	-$ 418,481	$ -	-$ 2,488,019	$ 7,973,689
47	1840	Underground Conduit		$ 10,628,960	$ 641,725	$ -	$ 11,270,685	-$ 2,809,075	-$ 450,828	$ -	-$ 3,259,903	$ 8,010,782
47	1845	Underground Conductors & Devices		$ 11,158,523	$ 1,856,542	$ -	$ 13,015,065	-$ 1,580,663	-$ 534,022	$ -	-$ 2,114,685	$ 10,900,380
47	1850	Line Transformers		$ 13,619,321	$ 1,180,002	$ -	$ 14,799,323	-$ 3,103,832	-$ 595,764	$ -	-$ 3,699,596	$ 11,099,727
47	1855	Services (Overhead & Underground)		$ 637,358	$ 103,915	$ -	$ 741,273	-$ 47,749	-$ 36,874	$ -	-$ 84,623	$ 656,650
47	1860	Meters		$ 6,960,135	$ 259,720	$ -	$ 7,219,856	-$ 1,537,900	-$ 288,812	$ -	-$ 1,826,713	$ 5,393,143
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ -	$ 167,826	$ -	$ 167,826	$ -	-$ 33,566	$ -	-$ 33,566	$ 134,260
10	1930	Transportation Equipment		$ 2,352,981	$ 164,863	-$ 49,409	$ 2,468,434	-$ 1,438,613	-$ 246,533	$ 49,409	-$ 1,635,736	$ 832,698
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 110,829	$ 31,935	$ -	$ 142,764	-$ 49,094	-$ 14,272	$ -	-$ 63,366	$ 79,398
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 1,176	$ -	$ -	$ 1,176	-$ 471	-$ 236	$ -	-$ 707	$ 469
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1970	Load Management Controls - Customer Premises		$ 547,972	$ -	$ -	$ 547,972	-$ 392,711	-$ 54,797	$ -	-$ 447,508	$ 100,464
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 148,397	$ 198,266	$ -	$ 346,663	-$ 9,895	-$ 23,107	$ -	-$ 33,002	$ 313,661
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 2,016,598	-$ 627,570	$ -	-$ 2,644,169	$ 145,935	$ 105,762	$ -	$ 251,698	-$ 2,392,471
N/A	2040	Plant Held for Future Use			$ 115,404		$ 115,404			-$ 19,876	-$ 19,876	$ 95,528
	etc.										$ -	$ -
		Total		**$ 73,127,134**	**$ 5,158,937**	**-$ 49,409**	**$ 78,236,661**	**-$ 16,725,548**	**-$ 3,276,505**	**$ 49,409**	**-$ 19,952,643**	**$ 58,284,018**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 246,533
Stores Equipment	$ -
Net Depreciation	$ 3,029,972

Table 2.10: Fixed Asset Continuity Schedule – 2009

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2009**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 187,929	-$ 5,968	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ -	$ 5,968	$ -	$ 5,968	$ -	$ -	$ -	$ -	$ 5,968
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ 1,163,732	-$ 101,436	-$ 23,274	$ -	-$ 124,710	$ 1,039,022
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541	$ -	$ -	$ 4,469,541	-$ 444,646	-$ 111,739	$ -	-$ 556,385	$ 3,913,156
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ 74,427	-$ 20,101	-$ 2,481	$ -	-$ 22,582	$ 51,845
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 13,687,050	$ 828,621	$ -	$ 14,515,671	-$ 3,930,856	-$ 580,647	$ -	-$ 4,511,503	$ 10,004,168
47	1835	Overhead Conductors & Devices		$ 10,461,708	$ 468,598	$ -	$ 10,930,306	-$ 2,488,019	-$ 437,210	$ -	-$ 2,925,229	$ 8,005,077
47	1840	Underground Conduit		$ 11,270,685	$ 681,004	$ -	$ 11,951,689	-$ 3,259,903	-$ 478,072	$ -	-$ 3,737,975	$ 8,213,714
47	1845	Underground Conductors & Devices		$ 13,015,065	$ 1,877,443	$ -	$ 14,892,508	-$ 2,114,685	-$ 609,145	$ -	-$ 2,723,830	$ 12,168,678
47	1850	Line Transformers		$ 14,799,323	$ 973,674	$ -	$ 15,772,997	-$ 3,699,596	-$ 634,684	$ -	-$ 4,334,280	$ 11,438,717
47	1855	Services (Overhead & Underground)		$ 741,273	$ 146,412	$ -	$ 887,685	-$ 84,623	-$ 41,314	$ -	-$ 125,937	$ 761,748
47	1860	Meters		$ 7,219,856	$ 424,756	$ -	$ 7,644,612	-$ 1,826,713	-$ 241,581	$ -	-$ 2,068,293	$ 5,576,318
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 167,826	$ 28,529	$ -	$ 196,355	-$ 33,566	-$ 39,270	$ -	-$ 72,836	$ 123,519
10	1930	Transportation Equipment		$ 2,468,434	$ 312,919	-$ 100,056	$ 2,681,297	-$ 1,635,736	-$ 275,557	$ 100,056	-$ 1,811,237	$ 870,060
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 142,764	$ 35,793	$ -	$ 178,557	-$ 63,366	-$ 17,859	$ -	-$ 81,225	$ 97,332
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 1,176	$ -	$ -	$ 1,176	-$ 707	-$ 236	$ -	-$ 943	$ 233
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1970	Load Management Controls - Customer Premises		$ 547,972	$ -	$ -	$ 547,972	-$ 447,508	-$ 54,797	$ -	-$ 502,305	$ 45,667
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 346,663	$ 97,406	$ -	$ 444,069	-$ 33,002	-$ 29,731	$ -	-$ 62,733	$ 381,336
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 2,644,169	-$ 745,257	$ -	-$ 3,389,425	$ 251,698	$ 135,584	$ -	$ 387,281	-$ 3,002,144
N/A	2040	Plant Held for Future Use		$ 115,404	$ 17,515	-$ 95,592	$ 37,327	-$ 19,876	$ -	$ 19,876	$ -	$ 37,327
	etc.						$ -				$ -	$ -
		Total		**$ 78,236,661**	**$ 5,147,412**	**-$ 195,649**	**$ 83,188,424**	**-$ 19,952,643**	**-$ 3,442,012**	**$ 119,933**	**-$ 23,274,722**	**$ 59,913,702**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 275,557
Stores Equipment	
Net Depreciation	$ 3,166,455

Table 2.11: Fixed Asset Continuity Schedule – 2010

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2010**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land		$ 181,961	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ 5,968	$ -	$ -	$ 5,968	$ -	$ -	$ -	$ -	$ 5,968
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ 1,163,732	-$ 124,710	-$ 23,274	$ -	-$ 147,984	$ 1,015,748
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541	$ -	$ -	$ 4,469,541	-$ 556,385	-$ 111,739	$ -	-$ 668,124	$ 3,801,417
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ 74,427	-$ 22,582	-$ 2,481	$ -	-$ 25,063	$ 49,364
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 14,515,671	$ 778,060	$ -	$ 15,293,731	-$ 4,511,503	-$ 611,734	$ -	-$ 5,123,237	$ 10,170,494
47	1835	Overhead Conductors & Devices		$ 10,930,306	$ 530,675	$ -	$ 11,460,981	-$ 2,925,229	-$ 458,439	$ -	-$ 3,383,668	$ 8,077,313
47	1840	Underground Conduit		$ 11,951,689	$ 647,491	$ -	$ 12,599,181	-$ 3,737,975	-$ 503,959	$ -	-$ 4,241,935	$ 8,357,246
47	1845	Underground Conductors & Devices		$ 14,892,508	$ 1,378,158	$ -	$ 16,270,666	-$ 2,723,830	-$ 623,972	$ -	-$ 3,347,803	$ 12,922,864
47	1850	Line Transformers		$ 15,772,997	$ 781,090	$ -	$ 16,554,086	-$ 4,334,280	-$ 654,598	$ -	-$ 4,988,877	$ 11,565,209
47	1855	Services (Overhead & Underground)		$ 887,685	$ 189,738	$ -	$ 1,077,423	-$ 125,937	-$ 31,495	$ -	-$ 157,432	$ 919,991
47	1860	Meters		$ 7,644,612	$ 1,088,510	$ -	$ 8,733,121	-$ 2,068,293	-$ 349,469	$ -	-$ 2,417,762	$ 6,315,359
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 196,355	$ 31	$ -	$ 196,386	-$ 72,836	-$ 39,278	$ -	-$ 112,114	$ 84,272
10	1930	Transportation Equipment		$ 2,681,297	$ 248,832	-$ 206,784	$ 2,723,344	-$ 1,811,237	-$ 266,240	$ 206,784	-$ 1,870,692	$ 852,652
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 178,557	$ 14,757	$ -	$ 193,313	-$ 81,225	-$ 18,422	$ -	-$ 99,646	$ 93,667
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 1,176	$ -	$ -	$ 1,176	-$ 943	-$ 233	$ -	-$ 1,176	$ -
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1970	Load Management Controls - Customer Premises		$ 547,972	$ -	$ -	$ 547,972	-$ 502,305	-$ 45,667	$ -	-$ 547,972	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 444,069	$ 208,548	$ -	$ 652,617	-$ 62,733	-$ 43,509	$ -	-$ 106,243	$ 546,375
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 3,389,425	-$ 196,588	$ -	-$ 3,586,013	$ 387,281	$ 143,429	$ -	$ 530,710	-$ 3,055,303
N/A	2040	Plant Held for Future Use		$ 37,327	$ 52,910	-$ 38,421	$ 51,816	$ -	$ -	$ -	$ -	$ 51,816
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 83,188,424**	**$ 5,722,212**	**-$ 245,206**	**$ 88,665,431**	**-$ 23,274,722**	**-$ 3,641,081**	**$ 206,784**	**-$ 26,709,019**	**$ 61,956,412**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ 266,240
Stores Equipment	
Net Depreciation	$ 3,374,841

Table 2.12: Fixed Asset Continuity Schedule – 2011

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2011**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land		$ 181,961	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ 5,968	$ -	$ -	$ 5,968	$ -	$ -	$ -	$ -	$ 5,968
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ 1,163,732	-$ 147,984	-$ 23,274	$ -	-$ 171,258	$ 992,474
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,469,541	$ 38,370	$ -	$ 4,507,912	-$ 668,124	-$ 112,708	$ -	-$ 780,833	$ 3,727,079
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ 74,427	-$ 25,063	-$ 2,481	$ -	-$ 27,544	$ 46,883
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 15,293,731	$ 680,278	$ -	$ 15,974,010	-$ 5,123,237	-$ 638,939	$ -	-$ 5,762,177	$ 10,211,833
47	1835	Overhead Conductors & Devices		$ 11,460,981	$ 655,233	$ -	$ 12,116,215	-$ 3,383,668	-$ 484,656	$ -	-$ 3,868,325	$ 8,247,890
47	1840	Underground Conduit		$ 12,599,181	$ 686,869	$ -	$ 13,286,049	-$ 4,241,935	-$ 531,437	$ -	-$ 4,773,371	$ 8,512,678
47	1845	Underground Conductors & Devices		$ 16,270,666	$ 1,145,510	$ -	$ 17,416,176	-$ 3,347,803	-$ 696,655	$ -	-$ 4,044,458	$ 13,371,719
47	1850	Line Transformers		$ 16,554,086	$ 478,372	$ -	$ 17,032,458	-$ 4,988,877	-$ 681,295	$ -	-$ 5,670,172	$ 11,362,286
47	1855	Services (Overhead & Underground)		$ 1,077,423	$ 191,941	$ -	$ 1,269,364	-$ 157,432	-$ 50,766	$ -	-$ 208,198	$ 1,061,166
47	1860	Meters		$ 8,733,121	$ 411,892	$ -	$ 9,145,013	-$ 2,417,762	-$ 629,086	$ -	-$ 3,046,849	$ 6,098,164
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 196,386	$ 238,943	$ -	$ 435,329	-$ 112,114	-$ 87,064	$ -	-$ 199,178	$ 236,151
10	1930	Transportation Equipment		$ 2,723,344	$ 309,767	$ -	$ 3,033,111	-$ 1,870,692	-$ 271,416	$ -	-$ 2,142,108	$ 891,003
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 193,313	$ 1,380	-$ 54,401	$ 140,292	-$ 99,646	-$ 14,030	$ 54,401	-$ 59,275	$ 81,017
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 1,176	$ -	-$ 1,176	$ -	-$ 1,176	$ -	$ 1,176	$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls - Customer Premises		$ 547,972	$ -	-$ 547,972	$ -	-$ 547,972	$ -	$ 547,972	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 652,617	$ 7,702	$ -	$ 660,319	-$ 106,243	-$ 43,982	$ -	-$ 150,224	$ 510,095
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 3,586,013	-$ 265,560	$ -	-$ 3,851,573	$ 530,710	$ 154,073	$ -	$ 684,783	-$ 3,166,790
N/A	2040	Plant Held for Future Use		$ 51,816	$ 2,940	$ -	$ 54,756	$ -	$ -	$ -	$ -	$ 54,756
	etc.						$ -					
		Total		**$ 88,665,431**	**$ 4,583,636**	**-$ 603,550**	**$ 92,645,518**	**-$ 26,709,019**	**-$ 4,113,716**	**$ 603,550**	**-$ 30,219,185**	**$ 62,426,332**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 271,416
Stores Equipment	
Net Depreciation	$ 3,842,300

Table 2.13: Fixed Asset Continuity Schedule – 2012 (CGAAP)

Appendix 2-B
Fixed Asset Continuity Schedule

Year **2012**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ 180,900	$ 435,329	$ 616,229	$ -	-$ 122,545	-$ 199,178	-$ 321,723	$ 294,506
CEC	1612	Land Rights (Formally known as Account 1906)		$ -	$ 64,700	$ 5,968	$ 70,668	$ -	-$ 7,262	$ -	-$ 7,262	$ 63,406
N/A	1805	Land		$ 181,961	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ 5,968	$ -	-$ 5,968	$ -		$ -	$ -	$ -	$ -
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ 1,163,732	-$ 171,258	-$ 23,274	$ -	-$ 194,532	$ 969,200
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,507,912	$ -	$ -	$ 4,507,912	-$ 780,833	-$ 112,698	$ -	-$ 893,531	$ 3,614,381
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ 74,427	-$ 27,544	-$ 2,481	$ -	-$ 30,025	$ 44,402
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 15,974,010	$ 584,500	$ -	$ 16,558,510	-$ 5,762,177	-$ 663,581	$ -	-$ 6,425,758	$ 10,132,752
47	1835	Overhead Conductors & Devices		$ 12,116,215	$ 959,300	$ -	$ 13,075,515	-$ 3,868,325	-$ 522,660	$ -	-$ 4,390,985	$ 8,684,530
47	1840	Underground Conduit		$ 13,286,049	$ 519,300	$ -	$ 13,805,349	-$ 4,773,371	-$ 552,655	$ -	-$ 5,326,026	$ 8,479,323
47	1845	Underground Conductors & Devices		$ 17,416,176	$ 1,876,200	$ -	$ 19,292,376	-$ 4,044,458	-$ 772,213	$ -	-$ 4,816,671	$ 14,475,706
47	1850	Line Transformers		$ 17,032,458	$ 796,400	$ -	$ 17,828,858	-$ 5,670,172	-$ 713,874	$ -	-$ 6,384,046	$ 11,444,812
47	1855	Services (Overhead & Underground)		$ 1,269,364	$ 135,200	$ -	$ 1,404,564	-$ 208,198	-$ 55,543	$ -	-$ 263,741	$ 1,140,823
47	1860	Meters		$ 9,145,013	$ 274,471	-$ 5,269,572	$ 4,149,912	-$ 3,046,849	-$ 378,890	$ 2,032,381	-$ 1,393,357	$ 2,756,554
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -	$ 5,000	$ -	$ 5,000	$ -	-$ 500	$ -	-$ 500	$ 4,500
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ -	$ 1,000	$ -	$ 1,000	$ -	-$ 200	$ -	-$ 200	$ 800
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ 435,329	$ -	-$ 435,329	$ -	-$ 199,178	$ -	$ 199,178	$ -	$ -
10	1930	Transportation Equipment		$ 3,033,111	$ 325,000	$ -	$ 3,358,111	-$ 2,142,108	-$ 203,065	$ -	-$ 2,345,173	$ 1,012,938
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 140,292	$ 25,000	$ -	$ 165,292	-$ 59,275	-$ 14,030	$ -	-$ 73,305	$ 91,987
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls - Customer Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 660,319	$ 83,000	$ -	$ 743,319	-$ 150,224	-$ 48,869	$ -	-$ 199,093	$ 544,226
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 3,851,573	-$ 623,500	$ -	-$ 4,475,073	$ 684,783	$ 154,072	$ -	$ 838,855	-$ 3,636,218
N/A	2040	Plant Held for Future Use		$ 54,756	$ -	-$ 54,756	-$ 0	$ -	$ -	$ -	$ -	-$ 0
	etc.			$ -			$ -				$ -	$ -
				$ -								
		Total		**$ 92,645,518**	**$ 5,206,471**	**-$ 5,324,328**	**$ 92,527,660**	**-$ 30,219,185**	**-$ 4,040,268**	**$ 2,032,381**	**-$ 32,227,071**	**$ 60,300,589**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 203,065
Stores Equipment	
Net Depreciation	$ 3,837,203

1 Table 2.14: Fixed Asset Continuity Statement – 2013 (Modified CGAAP)

Appendix 2-B
Fixed Asset Continuity Schedule

Year 2013

				Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Reallocate Smart Meters**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Reallocate Smart Meters**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 616,229	$ 1,963	$ 310,000	$ -	$ 928,192	-$ 321,723	-$ 647	-$ 121,074	$ -	-$ 443,444	$ 484,748
CEC	1612	Land Rights (Formally known as Account 1906)		$ 70,668	$ -	$ -	$ -	$ 70,668	-$ 7,262	$ -	-$ 1,294	$ -	-$ 8,556	$ 62,112
N/A	1805	Land		$ 181,961	$ -	$ -	$ -	$ 181,961	$ -	$ -	$ -	$ -	$ -	$ 181,961
CEC	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1808	Buildings		$ 1,163,732	$ -	$ -	$ -	$ 1,163,732	-$ 194,532	$ -	-$ 27,086	$ -	-$ 221,618	$ 942,114
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 4,507,912	$ -	$ -	$ -	$ 4,507,912	-$ 893,531	$ -	-$ 104,104	$ -	-$ 997,635	$ 3,510,277
47	1820	Distribution Station Equipment <50 kV		$ 74,427	$ -	$ -	$ -	$ 74,427	-$ 30,025	$ -	-$ 1,560	$ -	-$ 31,585	$ 42,842
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 16,558,510	$ -	$ 215,000	$ -	$ 16,773,510	-$ 6,425,758	$ -	-$ 374,253	$ -	-$ 6,800,011	$ 9,973,499
47	1835	Overhead Conductors & Devices		$ 13,075,515	$ -	$ 958,000	$ -	$ 14,033,515	-$ 4,390,985	$ -	-$ 243,122	$ -	-$ 4,634,107	$ 9,399,408
47	1840	Underground Conduit		$ 13,805,349	$ -	$ 35,000	$ -	$ 13,840,349	-$ 5,326,026	$ -	-$ 233,392	$ -	-$ 5,559,418	$ 8,280,931
47	1845	Underground Conductors & Devices		$ 19,292,376	$ -	$ 856,100	$ -	$ 20,148,476	-$ 4,816,671	$ -	-$ 640,974	$ -	-$ 5,457,645	$ 14,690,832
47	1850	Line Transformers		$ 17,828,858	$ -	$ 502,000	$ -	$ 18,330,858	-$ 6,384,046	$ -	-$ 447,040	$ -	-$ 6,831,086	$ 11,499,772
47	1855	Services (Overhead & Underground)		$ 1,404,564	$ -	$ 110,000	$ -	$ 1,514,564	-$ 263,741	$ -	-$ 56,061	$ -	-$ 319,802	$ 1,194,762
47	1860	Meters		$ 4,149,912	$ -	$ 205,000	$ -	$ 4,354,912	-$ 1,393,357	$ -	-$ 427,843	$ -	-$ 1,821,201	$ 2,533,711
47	1860	Meters (Smart Meters)		$ -	$ 5,329,835	$ -	$ -	$ 5,329,835	$ -	-$ 978,737	-$ 355,322	$ -	-$ 1,334,059	$ 3,995,776
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 5,000	$ -	$ -	$ -	$ 5,000	-$ 500	$ -	-$ 500	$ -	-$ 1,000	$ 4,000
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware		$ 1,000	$ 41,939	$ 77,500	$ -	$ 120,439	-$ 200	-$ 28,940	-$ 18,326	$ -	-$ 47,466	$ 72,973
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1925	Computer Software		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment		$ 3,358,111	$ -	$ 200,000	$ -	$ 3,558,111	-$ 2,345,173	$ -	-$ 161,947	$ -	-$ 2,507,120	$ 1,050,991
8	1935	Stores Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 165,292	$ -	$ 25,000	$ -	$ 190,292	-$ 73,305	$ -	-$ 17,781	$ -	-$ 91,086	$ 99,206
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls - Customer Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment		$ 743,319	$ -	$ 150,000	$ -	$ 893,319	-$ 199,093	$ -	-$ 31,605	$ -	-$ 230,698	$ 662,621
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 4,475,073	$ -	-$ 203,440	$ -	-$ 4,678,513	$ 838,855	$ -	$ 105,753	$ -	$ 944,608	-$ 3,733,905
N/A	2040	Plant Held for Future Use		-$ 0	$ -	$ -	$ -	-$ 0	$ -	$ -	$ -	$ -	$ -	-$ 0
	etc.							$ -					$ -	$ -
								$ -						
		Total		**$ 92,527,660**	**$ 5,373,737**	**$ 3,440,160**	**$ -**	**$ 101,341,557**	**-$ 32,227,071**	**-$ 1,008,324**	**-$ 3,157,531**	**$ -**	**-$ 36,392,926**	**$ 64,948,631**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ 161,947
Stores Equipment	
Net Depreciation	$ 2,995,584

Capital Projects Exceeding Materiality Threshold:

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.

2.15: 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

The following section sets out the year over year variances in BPI's capital expenditures by the Board's USoA classification. Also provided are the annual fixed asset continuity schedules, capital projects by USoA and explanations for the capital projects exceeding the materiality threshold of $70,000. This information has been presented for the years 2008 to 2011 Actuals, the 2012 Bridge Year and the 2013 Test Year.

Table 2.16 below, sets out the year over year gross asset variances by the Board's USoA classification. BPI has prepared the year over year analysis in a consistent format for comparison purposes.

1 **Table 2.16: GROSS ASSETS (CGAAP)**

OEB	Description	2008 Board Approved ($)	2008 Actual ($)	Variance from 2008 Board Aproved	2009 Actual ($)	Variance from 2008 Actual	2010 Actual ($)	Variance from 2009 Actual	2011 Actual ($)	Variance from 2010 Actual	2012 Bridge ($)	Variance from 2011 Actual	2013 Test ($)	Variance from 2012 Bridge
Land and Buildings														
1805	Land	208,241.00	187,929	(20,312)	181,961	(5,968)	181,961	-	181,961	-	181,961	-	181,961	-
1806	Land Rights	-	-		5,968	5,968	5,968	-	5,968	-	70,668	64,700	70,668	-
1808	Buildings and Fixtures	1,192,568.00	1,163,732	(28,836)	1,163,732	-	1,163,732	-	1,163,732	-	1,163,732	-	1,163,732	-
1810	Leasehold Improvements	-	-		-	-	-	-	-	-	-	-	-	-
	Sub-Total-Land and Buildings	**1,400,809.00**	**1,351,661**	**(49,148)**	**1,351,661**	**(0)**	**1,351,661**	**-**	**1,351,661**	**-**	**1,416,361**	**64,700**	**1,416,361**	**-**
TS Primary Above 50														
1815	Transformer Station Equipment - Normally Primary above 50 kV	4,469,541.00	4,469,541	0	4,469,541	-	4,469,541	-	4,507,912	38,370	4,507,912	-	4,507,912	-
	Sub-Total-TS Primary aove 50 kV	**4,469,541.00**	**4,469,541**	**0**	**4,469,541**	**-**	**4,469,541**	**-**	**4,507,912**	**38,370**	**4,507,912**	**-**	**4,507,912**	**-**
DS														
1820	Distribution Station Equipment - Normally Primary below 50 kV	140,683.00	74,427	(66,256)	74,427	-	74,427	-	74,427	-	74,427	-	74,427	-
	Sub-Total-DS	**140,683.00**	**74,427**	**(66,256)**	**74,427**	**-**	**74,427**	**-**	**74,427**	**-**	**74,427**	**-**	**74,427**	**-**
Poles and Wires														
1830	Poles, Towers and Fixtures	11,970,494.00	13,687,050	1,716,556	14,515,671	828,621	15,293,731	778,060	15,974,010	680,278	16,558,510	584,500	16,773,510	215,000
1835	Overhead Conductors and Devices	11,339,034.00	10,461,708	(877,326)	10,930,306	468,598	11,460,981	530,675	12,116,215	655,233	13,075,515	959,300	14,033,515	958,000
1840	Underground Conduit	10,519,300.00	11,270,685	751,385	11,951,689	681,004	12,599,181	647,491	13,286,049	686,869	13,805,349	519,300	13,840,349	35,000
1845	Underground Conductors and Devices	12,343,058.00	13,015,065	672,007	14,892,508	1,877,443	16,270,666	1,378,158	17,416,176	1,145,510	19,292,376	1,876,200	20,148,476	856,100
	Sub-Total-Poles and Wires	**46,171,886.00**	**48,434,509**	**2,262,623**	**52,290,175**	**3,855,665**	**55,624,560**	**3,334,385**	**58,792,450**	**3,167,891**	**62,731,750**	**3,939,300**	**64,795,850**	**2,064,100**
Line Transformers														
1850	Line Transformers	13,600,977.00	14,799,323	1,198,346	15,772,997	973,674	16,554,086	781,090	17,032,458	478,372	17,828,858	796,400	18,330,858	502,000
	Sub-Total-Line Transformers	**13,600,977.00**	**14,799,323**	**1,198,346**	**15,772,997**	**973,674**	**16,554,086**	**781,090**	**17,032,458**	**478,372**	**17,828,858**	**796,400**	**18,330,858**	**502,000**
Services and Meters														
1855	Services	982,923.00	741,273	(241,650)	887,685	146,412	1,077,423	189,738	1,269,364	191,941	1,404,564	135,200	1,514,564	110,000
1860	Meters	7,118,641.00	7,219,856	101,215	7,644,612	424,756	8,733,121	1,088,510	9,145,013	411,892	4,149,912	(4,995,101)	9,684,747	5,534,836
	Sub-Total-Meters and Services	**8,101,564.00**	**7,961,128**	**(140,436)**	**8,532,297**	**571,168**	**9,810,544**	**1,278,248**	**10,414,377**	**603,833**	**5,554,475**	**(4,859,901)**	**11,199,311**	**5,644,836**
General Plant														
1905	Land	-	-	-	-	-	-	-	-	-	-	-	-	-
1906	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-Total-General Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
IT Assets														
1920	Computer Equipment - Hardware	-	-	-	-	-	-	-	-	-	1,000	1,000	120,439	119,439
1925	Computer Software	110,000.00	167,826	57,826	196,355	28,529	196,386	31	435,329	238,943	616,229	180,900	928,192	311,963
	Sub-Total-IT assets	**110,000.00**	**167,826**	**57,826**	**196,355**	**28,529**	**196,386**	**31**	**435,329**	**238,943**	**617,229**	**181,900**	**1,048,631**	**431,402**
Equipment														
1915	Office Furniture and Equipment	-	-	-	-	-	-	-	-	-	5,000	5,000	5,000	-
1930	Transportation Equipment	2,700,274.00	2,468,434	(231,840)	2,681,297	212,862	2,723,344	42,047	3,033,111	309,767	3,358,111	325,000	3,558,111	200,000
1935	Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	120,073.00	142,764	22,691	178,557	35,793	193,313	14,757	140,292	(53,021)	165,292	25,000	190,292	25,000
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	1,176.00	1,176	0	1,176	-	1,176	-	-	(1,176)	-	-	-	-
1960	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-Total-Equipment	**2,821,523.00**	**2,612,374**	**(209,149)**	**2,861,030**	**248,655**	**2,917,833**	**56,804**	**3,173,403**	**255,570**	**3,528,403**	**355,000**	**3,753,403**	**225,000**
Other Distribution Assets														
1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1970	Load Management Controls - Customer Premises	547,972.00	547,972	0	547,972	-	547,972	-	-	(547,972)	-	-	-	-
1975	Load Management Controls - Utility Premises	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	System Supervisory Equipment	295,000.00	346,663	51,663	444,069	97,406	652,617	208,548	660,319	7,702	743,319	83,000	893,319	150,000
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	-	-	-	-	-	-	-	-	-	-	-	-	-
1995	Contributions and Grants	(1,564,914.00)	(2,644,169)	(1,079,255)	(3,389,425)	(745,257)	(3,586,013)	(196,588)	(3,851,573)	(265,560)	(4,475,073)	(623,500)	(4,678,513)	(203,440)
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	Plant Held for Future Use	-	115,404	115,404	37,327	(78,077)	51,816	14,489	54,756	2,940	-	(54,756)	-	-
	Sub-Total-Other Distribution Asse	**(721,942.00)**	**(1,634,129)**	**(912,187)**	**(2,360,057)**	**(725,928)**	**(2,333,607)**	**26,450**	**(3,136,498)**	**(802,891)**	**(3,731,754)**	**(595,256)**	**(3,785,194)**	**(53,440)**
2055	Work in Process	-	44,337		68,416	24,078	104,107	35,692	24,009	(80,098)	24,009	(0)	24,009	-
	GROSS ASSET TOTAL	76,095,041.00	78,280,998.19	2,141,619.94	83,256,840	4,975,842	88,769,538	5,512,698	92,669,527	3,899,989	92,551,669	(117,857)	101,365,567	8,813,897

VARIANCE ANALYSIS ON GROSS ASSETS:

2008 Board Approved to 2008 Actual

In accordance with the Minimum Filing Requirements, BPI has analysed variances back to the 2008 Board-approved values as well as 2008 actual amounts. 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.

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 capital spending is $35,937.

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

In 2008 Actual, annual rebuilds of existing lines and equipment including spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers took place, with an increased cost of $1,716,556. Another significant project was the conversion of lines from 4/8 kV to 27.6 voltage levels for Applewood and Brier Park Subdivisions (capital project #9). Capital projects are assigned a reference number which is used later on in the evidence, explained in Capital Projects by Year and USoA. The conversion project involved the rebuild of poles, towers and fixtures, overhead conductors and devices and underground conduit at a cost of $1,198,346. Accompanying cost increases over the Board Approved year that went along with the annual rebuilds of existing lines and equipment were $751,385 for underground conduit, $672,007 for underground conductors and devices, and a reduced cost of ($877,326) for overhead conductors and devices (capital project #10). Services expenditures declined by ($241,650) to reflect the change in work priorities between what was budgeted and work actually performed.

Replacement of failed meters and installation of new meters (capital project #12) for new customers increased by $101,215 over Board Approved and vehicle replacements (capital project #13) cost were ($231,840) less than 2008 Board Approved. Monies paid for third party contributions towards the cost of constructing BPI assets (Capital Contributions and Grants) were ($1,079,255) less than the Board Approved.

2008 Actual to 2009 Actual

The variance in gross assets for 2008 Actual compared to 2009 Actual was the result of capital expenditures in 2009.

Pole replacement under Powerline project (capital project #6) started in 2009 and will continue until BPI reaches the east end of the City by 2016, subject to budget approvals for this project This cost was an increase of $828,621 over 2008.

Cost increases in 2009 that accompanied rebuilds, conversions, and new subdivisions and townhomes included $681,004 for underground conduit, $468,598 for overhead conductors and devices and $1,877,443 for underground conductors and devices.

Increase in transformer size owned by BPI from 1000 kVA to 1500 kVA at 347/600V to accommodate larger electrical loads came at a higher cost of $973,674 in 2009.

The main drivers for the variance in the Services account were expansion projects and change of ownership of distribution assets as BPI amended its Conditions of Service to change its demarcation point from the property line to the customer's meter base. The increased cost over 2009 was $146,412.

In 2009, BPI purchased a Yard/Crane Truck to replace another Yard/Crane Truck originally purchased in 1987 at an increased cost of $212,862 (capital project #13). Also, an automatic recloser was installed on the 64M25 feeder at the boundary of the BPI/BCPI service territories at an increased cost of $97,406 over 2008 (capital project #8).

Capital contributions and grants - monies paid for third party contributions towards the cost of constructing BPI assets amounted to ($745,257) over 2008.

2009 Actual to 2010 Actual

Accompanying cost increases in 2010 that went with rebuilds, conversions, and new subdivisions and townhomes included $778,060 over 2009 for poles, towers and fixtures, $530,675 more than 2009 for overhead conductors and devices, $647,491 for underground conduits, and $1,378,158 for underground conductors and devices.

An increase in the size of transformers owned by BPI from 1000 kVA to 1500 kVA to accommodate larger electrical loads came at a higher cost of $781,090.

Services had a cost increase of $189,738 as a result of BPI's rebuild of Brantwood plus accompanying costs for nondiscretionary projects such as overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and line transformers.

Another cost increase of $1,088,510 in 2010 over 2009 was incurred because BPI was required to upgrade the IESO Wholesale Revenue Metering (WRM) installation at Brantford TS to the latest IESO metering specification (capital project #11). As the metering equipment was located on a Hydro One owned High Voltage bus, Hydro One was the only contractor who could complete the engineering and installation work.

Another cost increase of $208,548 over 2009 was a result of Major SCADA software/hardware upgrades being undertaken; from a Virtual Memory System ("VMS") to a Windows platform because BPI's original VMS SCADA system was no longer supported by the SCADA vendor (capital project #7).

Capital contributions and grants - monies paid for third party contributions towards the cost of constructing BPI assets amounted to ($196,588) over 2009.

2010 Actual to 2011 Actual

Cost increases incurred in respect of rebuilds, conversions, and construction of new subdivisions and townhomes included $680,278 for poles, towers and fixtures, $655,233 for overhead conductors and devices, $686,869 for underground conduit, and $1,145,510 for underground conductors and devices. Also, a rebuild of the Brantwood/Dunsdon subdivision resulted in an increased cost of $478,372 over 2010 (capital project #9).

As BPI had mostly completed its smart meter installations by 2011, the additions to meter capital spending in the amount of $411,892, more than in 2010 were normal course of business, new customer meter installations.

Services costs increased by $191,941 as a result of accompanying costs incurred for essential annual rebuilds of exiting lines and equipment and nondiscretionary projects such as overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and line transformers.

An increase in computer software costs in the amount of $238,943 was a result of all activities outlined in the 5-year asset management plan involving consultancy work and supervision by Urban and Environment Management (“UEM”), GIS related upgrades and new software installation by Intergraph (GIS vendor) and UEM as well as individual data collection, assimilation, storage and processing by BPI staff and City of Brantford IT Services (capital projects #10 & 11).

In 2011, an increased cost of $309,767 was a result of BPI purchasing a Line Truck to replace a 10 year old Line Truck that needed major repairs (capital project #14).

The write off of fully depreciated load control devices resulted in a cost decrease from 2010 of ($547,972). Capital contributions and grants decreased by ($265,560) and work-in-progress decreased by ($80,098).

2011 Actual to 2012 Bridge Year

The cost increases incurred in respect of rebuilds, conversions, and new subdivisions and townhomes that took place in the 2012 Bridge Year included $584,500 for poles, towers and fixtures, $959,300 for overhead conductors and devices, $519,300 for underground conduit and $1,876,200 for underground conductors and devices. Additionally, a significant rebuild project in the Lynden Hills area resulted in a $796,400 increase over 2011 (capital project #9). That project included replacing aging cables and removing submersible transformers and replacing with padmount transformers.

In 2012, BPI purchased a Smaller Cube Van to replace a 10 year old Larger Cube Van that needed major repairs at an increased cost of $325,000 over 2011 (capital project #11).

In 2012, BPI also removed stranded meters in the amount of ($4,995,101)

Capital grants and contributions were ($623,500) lower than in 2011.

Services costs increased by $135,200 as a result of costs related to essential annual rebuilds of exiting lines and equipment and nondiscretionary projects such as overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and line transformers.

Computer software cost increased by $180,900 as a result of BPI's Asset Management Consultancy and software (capital project #10).

2012 Bridge Year to 2013 Test Year

Forecasted cost increases in 2013 that pertain to rebuilds, conversions, and new subdivisions and townhomes include $215,000 for poles, towers and fixtures, $958,000 for overhead conductors and devices, $856,100 for underground conductors and devices and $502,000 for line transformers.

In 2013, BPI is bringing smart meter costs into rate base in the amount of $5,534,836.

In 2013, an increase in IT Assets in the amount of $431,402 reflects Customer Service requirements for a new Interactive Voice Response system (capital project #15) and other equipment under the materiality threshold. For a more detailed description of customer service transitions refer to Exhibit 4, Tab 2.

BPI also plans to purchase three vehicles – a large pick-up truck, a small pick-up truck and a one-ton truck to replace existing vehicles that have excessive mileage and/or expiry of service life causing an increase of $200,000 over 2012 (capital project #14).

Budgeted capital contributions and grants decreased by ($203,440) over 2012.

Services costs are forecasted to increase by $110,000 as a result of forecasted costs related to essential annual rebuilds of exiting lines and equipment and nondiscretionary projects such as overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and line transformers.

In 2013, an increase in the amount of $150,000 is also forecasted as BPI plans to:

- Install an automatic recloser and radio – circuit to be determined;
- Relocate SCADA HOST A server to Powerline MTS after fibre installation is complete; and
- Configure Inter-Control Centre Communications Protocol (“ICCP”) holdoff feature with Hydro One to allow BPI Operations Group to request holdoffs using SCADA.

ACCUMULATED AMORTIZATION TABLE:

Table 2.17: Accumulated Amortization

OEB	Description	2008 Board Approved ($)	2008 Actual ($)	Variance from 2008 Board Aproved	2009 Actual ($)	Variance from 2008 Actual	2010 Actual ($)	Variance from 2009 Actual	2011 Actual ($)	Variance from 2010 Actual	2012 Bridge ($)	Variance from 2011 Actual	2013 Test ($)	Variance from 2012 Bridge
Land and Buildings														
1805	Land	-	-	-	-	-	-	-	-	-	-	-	-	-
1806	Land Rights	-	-		-	-	-	-	-	-	7,262	7,262	8,556	1,294
1808	Buildings and Fixtures	106,090	101,436	(4,654)	124,710	23,274	147,984	23,274	171,258	23,274	194,532	23,274	221,618	27,086
1810	Leasehold Improvements	-	-		-	-	-	-	-	-	-	-	-	-
	Sub-Total-Land and Buildings	**106,090**	**101,436**	**(4,654)**	**124,710**	**23,274**	**147,984**	**23,274**	**171,258**	**23,274**	**201,794**	**30,536**	**230,174**	**28,380**
TS Primary Above 50														
1815	Transformer Station Equipment - Normally Primary above 50 kV	485,431	444,646	(40,785)	556,385	111,739	668,124	111,739	780,833	112,708	893,531	112,698	997,635	104,104
	Sub-Total-TS Primary aove 50 kV	**485,431**	**444,646**	**(40,785)**	**556,385**	**111,739**	**668,124**	**111,739**	**780,833**	**112,708**	**893,531**	**112,698**	**997,635**	**104,104**
DS														
1820	Distribution Station Equipment - Normally Primary below 50 kV	9,370	20,101	10,731	22,582	2,481	25,063	2,481	27,544	2,481	30,025	2,481	31,585	1,560
	Sub-Total-DS	**9,370.00**	**20,101**	**10,731**	**22,582**	**2,481**	**25,063**	**2,481**	**27,544**	**2,481**	**30,025**	**2,481**	**31,585**	**1,560**
Poles and Wires														
1830	Poles, Towers and Fixtures	506,966	3,930,856	3,423,890	4,511,503	580,647	5,123,237	611,734	5,762,177	638,939	6,425,758	663,581	6,800,011	374,253
1835	Overhead Conductors and Devices	5,024,814	2,488,019	(2,536,795)	2,925,229	437,210	3,383,668	458,439	3,868,325	484,656	4,390,985	522,660	4,634,107	243,122
1840	Underground Conduit	620,738	3,259,903	2,639,165	3,737,975	478,072	4,241,935	503,959	4,773,371	531,437	5,326,026	552,655	5,559,418	233,392
1845	Underground Conductors and Devices	5,600,634	2,114,685	(3,485,949)	2,723,830	609,145	3,347,803	623,972	4,044,458	696,655	4,816,671	772,213	5,457,645	640,974
	Sub-Total-Poles and Wires	**11,753,152**	**11,793,464**	**40,312**	**13,898,538**	**2,105,073**	**16,096,643**	**2,198,105**	**18,448,331**	**2,351,688**	**20,959,440**	**2,511,109**	**22,451,181**	**1,491,741**
Line Transformers														
1850	Line Transformers	3,646,729	3,699,596	52,867	4,334,280	634,684	4,988,877	654,598	5,670,172	681,295	6,384,046	713,874	6,831,086	447,040
	Sub-Total-Line Transformers	**3,646,729**	**3,699,596**	**52,867**	**4,334,280**	**634,684**	**4,988,877**	**654,598**	**5,670,172**	**681,295**	**6,384,046**	**713,874**	**6,831,086**	**447,040**
Services and Meters														
1855	Services	102,134	84,623	(17,511)	125,937	41,314	157,432	31,495	208,198	50,766	263,741	55,543	319,802	56,061
1860	Meters	1,828,961	1,826,713	(2,248)	2,068,293	241,581	2,417,762	349,469	3,046,849	629,086	1,393,357	(1,653,491)	3,155,259	1,761,902
	Sub-Total-Meters and Services	**1,931,095**	**1,911,335**	**(19,760)**	**2,194,230**	**282,895**	**2,575,194**	**380,964**	**3,255,046**	**679,852**	**1,657,098**	**(1,597,948)**	**3,475,061**	**1,817,963**
General Plant														
1905	Land	1,828,961	-	(1,828,961)	-	-	-	-	-	-	-	-	-	-
1906	Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-
1908	Buildings and Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-
1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-Total-General Plant	1,828,961	-	(1,828,961)	-	-	-	-	-	-	-	-	-	-
IT Assets														
1920	Computer Equipment - Hardware	-	-	-	-	-	-	-	-	-	200	200	47,466	47,266
1925	Computer Software	-	33,566	33,566	72,836	39,270	112,114	39,278	199,178	87,064	321,723	122,545	443,443	121,720
	Sub-Total-IT assets	**-**	**33,566**	**33,566**	**72,836**	**39,270**	**112,114**	**39,278**	**199,178**	**87,064**	**321,923**	**122,745**	**490,909**	**168,986**
Equipment														
1915	Office Furniture and Equipment	-	-	-	-	-	-	-	-	-	500	500	1,000	500
1930	Transportation Equipment	1,909,083.00	1,635,736	(273,347)	1,811,237	175,500	1,870,692	59,455	2,142,108	271,416	2,345,173	203,065	2,507,120	161,947
1935	Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	62,028.00	63,366	1,338	81,225	17,859	99,646	18,422	59,275	(40,371)	73,305	14,030	91,086	17,781
1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	-	707	707	943	236	1,176	233	-	(1,176)	-	-	-	-
1960	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-Total-Equipment	**1,971,111**	**1,699,809**	**(271,302)**	**1,893,405**	**193,595**	**1,971,514**	**78,110**	**2,201,383**	**229,869**	**2,418,978**	**217,595**	**2,599,206**	**180,228**
Other Distribution Assets														
1825	Storage Battery Equipment	9,370.00	-	(9,370)	-	-	-	-	-	-	-	-	-	-
1970	Load Management Controls - Customer Premises	447,507.00	447,508	1	502,305	54,797	547,972	45,667	-	(547,972)	-	-	-	-
1975	Load Management Controls - Utility Premises	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	System Supervisory Equipment	39,335.00	33,002	(6,333)	62,733	29,731	106,243	43,509	150,224	43,982	199,093	48,869	230,698	31,605
1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-	-	-	-	-
1990	Other Tangible Property	-	-	-	-	-	-	-	-	-	-	-	-	-
1995	Contributions and Grants	(199,094.00)	(251,698)	(52,604)	(387,281)	(135,584)	(530,710)	(143,429)	(684,783)	(154,073)	(838,855)	(154,072)	(944,608)	(105,753)
2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	Plant Held for Future Use	-	19,876	19,876	-	(19,876)	-	-	-	-	-	-	-	-
	Sub-Total-Other Distribution Asset	**297,118**	**248,689**	**(48,429)**	**177,757**	**(70,932)**	**123,505**	**(54,252)**	**(534,559)**	**(658,064)**	**(639,762)**	**(105,203)**	**(713,910)**	**(74,148)**
2055	Work in Process	(199,094)	44,337		-	(44,337)	104,107	104,107	-	(104,107)	-	-	24,009	24,009
	GROSS ASSET TOTAL	21,829,963.00	19,996,980.20	(2,076,414.05)	23,274,722	3,277,742	26,813,126	3,538,404	30,219,185	3,406,059	32,227,071	2,007,886	36,416,934	4,189,863

VARIANCE ANALYSIS ON ACCUMULATED AMORTIZATION:

Table 2.17 shows the changes in accumulated amortization from 2008 Actual to the 2013 Test Year. The change in accumulated amortization is a result of capital expenditures and amortization expense each year.

In addition, the following items have significantly impacted the variances in accumulated amortization over the 2008 Actual to 2013 Test Year period:

- During 2012 accumulated amortization relating to stranded meters in the amount of $2,032,381 was transferred to Account 1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs.
- On January 1, 2013 accumulated amortization of $1,008,323 for smart meter assets was transferred from Account 1555 to rate base.

BPI has reviewed the useful life of its assets with the aid of the *Asset Depreciation Study for the Ontario Energy Board* completed by Kinectrics Inc. dated July 8, 2010. The amortization expenses outlined are based on the new useful lives of the assets as discussed in Tab 3, Schedule 4 to this exhibit.

BPI has also provided its continuity statements for the 2012 Bridge Year and the 2013 Test Year to include these changes.

CAPITAL BUDGET:

INTRODUCTION

Starting in 2013 BPI's AMP identifies the capital projects required over a 5 year period based on the best available information for each year. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, BPI may be required to adjust the capital project forecast as the knowledge of its system needs increases. As provided in Exhibit 2, Tab 3, Schedule 2, a significant portion of BPI's non-discretionary capital investments are customer or municipal driven. All proposed capital projects for the 2012 Bridge Year have been completed and all proposed capital projects for the 2013 Test Year will be completed and in service in that year. Details of BPI's capital budget for these periods are provided in tables below following the "Introduction to Capital Plan".

Harmonized Sales Tax ("HST"):

Capital and OM&A expenditures are lower since July 1, 2010 as a result of being able to recover the 8% provincial portion of the HST. The 2013 budget reflects the reductions as it is based on 2011 and 2012 experience.

Introduction to Capital Plan:

BPI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending for the 2012 Bridge Year and the 2013 Test Year is broken down by account and by project in Exhibit 2, Tab 3, Schedule 2. Below is an analysis of BPI's capital spending from 2008 to 2013.

Table 2.18: Capital Spending Summary 2008 to 2013

Year	Total Distribution Plant ($)	Capital Contributions	Net Distribution Plant	General Plant	Total Capital net of Contributions	$ Increase/ (Decrease)	% Increase/ (Decrease)
2008	5,223,617	(627,570)	4,596,046	562,891	5,158,937	-	-
2009	5,400,507	(745,257)	4,655,250	474,647	5,129,897	(29,040)	-0.56%
2010	5,393,722	(196,588)	5,197,135	472,167	5,669,302	539,405	10.51%
2011	4,288,465	(265,560)	4,022,905	557,791	4,580,696	(1,088,606)	-19.20%
2012	5,210,071	(623,500)	4,586,571	619,900	5,206,471	625,775	13.66%
2013	2,881,100	(203,440)	2,677,660	762,500	3,440,160	(1,766,311)	-33.93%

The filing requirements for Exhibit 2 (Rate Base) request actual historical summary information for the last 4 years.

In 2010, the main driver of the increase of 10% over 2009 spending levels was the increase in transformer size owned by BPI from 1000 kVA to 1500 kVA to accommodate larger electrical loads and this came at higher cost. Also attributable to this was an increase in expenditures on various distribution system components (poles, conductors, conduit, transformers and services) and the rebuild of Brantwood.

In 2011 BPI's capital expenditures declined significantly by ($1,088,606) as no conversion projects were undertaken in 2011.

In 2012, BPI's capital expenditures increased by $625,775 as result of a return to a normal level of capital expenditures. 2011 was an anomaly, with no conversion projects having been undertaken. Exhibit 2, Tab 3, Schedule 2 provides details of projects that were undertaken in 2012.

For the 2013 Test Year, the main driver for the significant decrease of ($1,766,311) or 34% is the result of changes to the capitalization policy. In addition to this, as BPI's assets are now on a longer depreciation schedule due to the adoption of typical useful lives from the Asset Depreciation Study (Kinectrics Inc.), BPI has planned fewer rebuilds, resulting in a cost savings.

The capital spending numbers reported above in Table 2.18 are excluding all amounts of smart meter spending. These expenditures are discussed in Exhibit 9.

CAPITAL PROJECTS BY YEAR AND USoA

Introduction,

Board prescribed Chapter 2, Appendix 2-A is a summary of BPI's actual investment in construction projects for the years 2008, 2009, 2010, 2011 plus projects for the 2012 Bridge Year and 2013 Test Year. The grants and capital contributions portion represents what BPI expects to recover in the given year but is not specific to the projects.

Appendix 2-A
Capital Projects Table

Projects	2008	Projects	2009	Projects	2010	Projects	2011	Projects	2012 Bridge Year	Projects	2013 Test Year
Reporting Basis	CGAP		CGAP		CGAP		CGAP		CGAP		Modified CGAP
Capital Project #1- Residential Seconary Services	$ 93,448	Capital Project #1- Residential Seconary Services	$ 112,524	Capital Project #1- Residential Seconary Services	$ 156,047	Capital Project #1- Residential Seconary Services	$ 118,230	Capital Project #1- Residential Seconary Services	$ 134,156	Capital Project #1- Residential Seconary Services	$ 110,000
Capital Project #2 - Overhead Line Extensions	$ 263,594	Capital Project #2 - Overhead Line Extensions	$ 206,127	Capital Project #2 - Overhead Line Extensions	$ 354,061	Capital Project #2 - Overhead Line Extensions	$ 352,871	Capital Project #2 - Overhead Line Extensions	$ 179,453	Capital Project #2 - Overhead Line Extensions	$ 265,000
Capital Project #3 - Underground Line Extensions	$ 330,157	Capital Project #3 - Underground Line Extensions	$ 236,335	Capital Project #3 - Underground Line Extensions	$ 483,721	Capital Project #3 - Underground Line Extensions	$ 327,251	Capital Project #3 - Underground Line Extensions	$ 351,833	Capital Project #3 - Underground Line Extensions	$ 280,000
Capital Project #4 - Overhead Transformers	$ 314,189	Capital Project #4 - Overhead Transformers	$ 202,555	Capital Project #4- Underground Transformers	$ 593,583	Capital Project #4 - Overhead Transformers	$ 83,450	Capital Project #4 - Overhead Transformers	$ 156,725	Capital Project #4 - Overhead Transformers	$ 45,000
Capital Project #5 - Underground Transformers	$ 617,980	Capital Project #5 - Underground Transformers	$ 277,149	Capital Project #5- Powerline Feeder Upgrades	$ 524,514	Capital Project #5 - Underground Transformers	$ 508,860	Capital Project #5 - Underground Transformers	$ 210,587	Capital Project #5 - Underground Transformers	$ 360,000
Capital Project #6- New Subdivisions and Townhomes	$ 838,213	Capital Project #6 - Powerline Feeder Upgrades	$ 353,641	Capital Projects #6 - New Subdivisions and Townhomes	$ 265,408	Capital Project #6 - Powerline Feeder Upgrades	$ 489,849	Capital Project #6 - Powerline Feeder Upgrades	$ 692,218	Capital Project #6 - Powerline Feeder Upgrades	$ 450,000
Capital Project #7City/Ministry of Transportation Relocates	$ 103,262	Capital Project #7 - New Subdivisions and Townhomes	$ 1,654,016	Capital Project #7 - Scada & Distribution/ System Upgrade to Windows	$ 246,707	Capital Projects #7 -New Subdivisions and Townhomes	$ 328,556	Capital Project #7 New Subdivisions and Townhomes	$ 841,872	Capital Project #7 New Subdivisions and Townhomes	$ 446,100
Capital Project #8 - Scada & Distribution Automation/Brantford General Hospital Automatic Load Transfer System	$ 179,175	Capital Project #8 - Scada & Distribution Automation/Reloser Installation	$ 96,919	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ 432,011	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ 613,691	Capital Project #8 - Annual Pole Replacements - General Yearly Rebuilds	$ 660,709	Capital Project #8- Scada & Distribution Automation	$ 150,000
Capital Project #9- Conversion of Lines from 4 & 8 Kv to 27 KvSystem - Applewood & Brier Park Subdivision	$ 1,960,631	Capital Project #9 - Conversion of Lines from 4 & 8 Kv to 27 Kv System - Tranquility, Rosewood, etc.	$ 1,402,272	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park	$ 1,537,546	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Brantwood Park/Dunsdon Rebuild	$ 1,468,877	Capital Project #9 - Annual Pole Replacements - General Yearly Rebuilds - Lynden Hill Estates	$ 1,096,019	Capital Project #9- Capacitor Study/Installation of Line Banks	$ 120,000
Capital Project #10- Annual Pole Replacements - General Yearly Rebuilds	$ 471,404	Capital Project #10 - Annual Pole Replacements - General Yearly Rebuilds	$ 512,324	Capital Project #10- - Metering	$ 355,369	Capital Project #10 - Asset Management & Consultancy Software	$ 219,196	Capital Project #10 - Asset Management & Consultancy Software	$ 230,987	Capital Project #10- Ownership Transfers - Primary Services and older 27.6Kv Townhome Sites	$ 110,000
Capital Project #11 - AM/FM GIS System Upgrade	$ 241,944	Capital Project #11 - Testing of G-Technology Version 9.4	$ 70,814	Capital Project #11- - Wholesale Metering (Brantford TS)	$ 769,365	Capital Project #11 Upgrade to G-Technology Version 10	$ 75,249	Capital Project #11 - Replacement of Vehicles	$ 123,836	Capital Project #11 Annual Pole Replacements - General Yearly Rebuilds	$ 390,000
Capital Project #12 - Metering	$ 229,050	Capital Project #12 - Metering	$ 349,517	Capital Project #12- Replacement of Vehicles	$ 248,832	Capital Project #12 - Metering	$ 150,239	Capital Project #12 - Office Furniture & Computer Equipment	$ 106,553	Capital Project #12 - Asset Management Consultancy &Software	$ 150,000
Capital Project #13 - Replacement of Vehicles	$ 165,750	Capital Project #13 - Replacement of Vehicles	$ 312,919			Capital Project #13- - Wholesale Metering (Brantford TS)	$ 26,781	Capital Project #13 - Metering	$ 129,614	Capital Project #13 - Metering	$ 205,000
						Capital Project #14 - Replacement of Vehicles	$ 309,767			Capital Project #14 - Replacement of Vehicles	$ 200,000
										Capital Project #15 - Customer Services (CS) Requirements	$ 200,000
Capital Contributions	-$ 627,570	Capital Contributions	-$ 745,257	Capital Contribtuions	-$ 196,588	Capital Contributions	-$ 265,560	Capital Contributions	-$ 605,551	Capital Contributions	-$ 203,440
Sub Total:	$ 5,181,227	Sub Total:	$ 5,041,855	Sub Total:	$ 5,770,576	Sub Total:	$ 4,807,307	Sub Total:	$ 4,309,011	Sub Total:	$ 3,277,660
Miscellaneous	$ 22,289	Miscellaneous	-$ 88,042	Miscellaneous	$ 101,275	Miscellaneous	$ 226,611	Miscellaneous	-$ 897,460	Miscellaneous	-$ 162,500
Total:	$ 5,158,938	Total	$ 5,129,897	Total:	$ 5,669,301	Total:	$ 4,580,696	Total:	$ 5,206,471	Total:	$ 3,440,160

The tables below summarize BPI's actual investments in construction projects for the years 2008, 2009, 2010, 2011 plus projects for the 2012 Bridge Year and 2013 Test Year. Project descriptions are also provided.

2008 Capital Projects

1. NEW LINES & EQUIPMENT

General Description:

The New Lines and Equipment capital pool includes various essential and nondiscretionary builds. Projects in this pool include, among others:

- Secondary services for residential and commercial customers;
- Primary services including overhead and underground line, for industrial and commercial customers; and;
- Overhead and underground transformers for residential, commercial and industrial customers.

This capital pool is based on historical data as well as specific information provided by developers, electricians and engineering companies.

New Lines and Equipment Capital Projects include the following components:

Name of Capital Project	Residential Secondary Services
Capital Project #	1
USofA #	1830,1835,1840,1845,1850,1855
Project Need and Purpose	To provide residential secondary services from underground transformers to customers.
Project Scope	Expansion, roll-ins comprising mainly of residential customer connections.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2008
Actual Costs	$93,448
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

The major servicing projects that were completed in 2008 include:

- New Alta – Service Upgrade – 112 Adams Blvd.
- Brantford Mall – 300 King George Rd.
- Rictor Webb – Service Upgrade – 111 Easton Rd.
- New Service – 36 Adams Blvd
- Bell Lane Retirement Home – Diana Ave
- New Service – Bodine Dr.
- Relocation of Service – Brant Industrial – Wayne Gretzky Parkway
- Gretzky Center
- 55 Diana Ave
- 29 Bury Crt.
- Conklin Rd. (Shell Trail)
- Service relocation – 50 Market St./Clarence St.
- Primary Service - King George Rd. & Francis
- New Service – Preston Lansdowne School
- New switch – Terrace Hill @ St. Paul
- New service – 59 Bury Court
- New service – Aucion Building – Morton Ave.
- New service – King George/Giant Tiger
- New service – Versa Care – Park Rd. N.
- New service – East Side Mario's – King George Rd.
- New service – 60 Clench Ave.
- Term & Cable (New Dip for Service) - Fenridge Hampton Inn

Name of Capital Project	Overhead Line Extensions
Capital Project #	2
USofA #	1830, 1835, 1845
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, overhead portions of mostly general service customer connections and pole lines.

Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2008
Actual Costs	$263,594
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Underground Line Extensions
Capital Project #	3
USofA#	1840, 1845
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, underground portions of mostly general service customer connections including cables and ducts.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2008
Actual Costs	$330,157
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, all pole mount transformers for connection to residential and general service customers.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2008
Actual Costs	$314,189
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	Underground Transformers
Capital Project #	5
USofA #	1845/1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, all padmount transformers for connection mainly to general service customers.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2008
Actual Costs	$617,980
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

2. NEW SUBDIVISIONS AND TOWNHOMES

General Description:

The new subdivisions and new townhomes capital budget pool comprises essential and nondiscretionary projects to support new development. Work is required to connect new subdivisions and townhouses, principally through new underground conduit, conductors and devices to the distribution infrastructure.

Beginning in 2008 with the implementation of proposed changes to BPI's Conditions of Service and redefinition of the demarcation point from the property line to the meter base, BPI assumed ownership of connection assets to the meter base of new townhome projects. As expansion projects, the Economic Evaluation model is applied to all new subdivision and new townhome projects.

Name of Capital Project:	New Subdivisions & Townhomes
Capital Project #	6
USofA #	1830, 1840, 1845
Project Need and Purpose	Work is required to connect new subdivisions and new townhomes.
Project Scope	The project comprises supply and installation of new underground cable, conduit,

	transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure. The budget for this capital pool is based on historical data as well as specific information provided by developers, electricians and engineering companies.
Number of Customer Attachments	Estimated connection of 300 subdivision units and 100 townhome units. Estimate based on developer and/or builder plans.
Load	Estimated as 730 kwh per lot per month.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2008
Actual Costs	$838,213
Who performed the work [in-house vs. contracted]	Majority of the work is performed by building contractors as subcontractors to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

Projects completed in 2008 include:

- Wynfield West
- D'Aubigny
- D'Aubigny – Phase 3
- Grey St. Townhomes
- Diana Lane Townhomes
- McConkey Cres. Townhomes

3. CITY/MINISTRY OF TRANSPORTATION RELOCATIONS

General Description:

Prioritized as nondiscretionary essential capital projects, these projects involved relocation of overhead lines resulting from municipal or provincial road infrastructure projects.

Capital budget costs for system expansions and municipal and Ministry of Transportation Road Relocation Projects are presented as gross costs and do not include offsets for grants and grants and contributions which are booked to USoA Account 1995.

Name of Capital Project:	City /Ministry of Transportation Relocations
Capital Project #	7
USofA #	1830, 1835
Project Need and Purpose	Relocation of overhead lines resulting from municipal or provincial road infrastructure projects.
Project Scope	It is often impossible to forecast what projects will require any relocation work because the final road designs are not finalized at the time when BPI submits the budget. Additionally, the City's road construction program can add or subtract streets at any time.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2008
Actual Costs	$103,262
Who performed the work [in-house vs. contracted]	In-house and contracted
Procurement method where work was contracted	Tender

Projects completed in 2008 include:

- Henry St.
- Queensway St.
- Kingsway St.

4. SCADA AND DISTRIBUTION AUTOMATION

General Description:

BPI installed a SCADA [Supervisory Control and Data Acquisition] System in 2004 to control and monitor its distribution infrastructure. In 2007, the SCADA System was connected to the

Hydro One Grid Control Centre in Barrie to provide access to operational data at the Hydro One owned Transformer Stations, Brant and Brantford, serving the BPI distribution service area.

Name of Capital Project:	Brantford General Hospital Automatic Load Transfer System
Capital Project #	8
USofA #	1980
Project Need & Purpose:	Brantford General Hospital automatic load transfer project in 2008 allowed the automation of load break switches to automatically transfer the hospital in the event of a power outage. The system also monitors voltage, current and power factor.
Project Scope	Pole line design work was contracted through S&C Electric. The design was reviewed and approved by BPI and equipment purchased and configured from S&C Electric. BPI installed the system. Commissioning was completed by BPI with the assistance of S&C Electric. BPI installed and commissioned the SCADA radio communications.
Cost-benefit analysis, as applicable	The automatic load transfer system transfers the hospital in less than 10 seconds in the event of a power outage. This is a major improvement in reliability to the customer. BPI no longer sends line persons in the field to perform manual switching for this customer.
Starting dates and in-service dates	2008
Actual Costs	$179,175
Who performed the work [in-house vs. contracted]	Contracted: Design work, In-house: installation completed by BPI.
Procurement method where work was contracted	Sole source - S&C Electric.

5. CONVERSION OF LINES FROM 4 AND 8 KV TO 27 KV SYSTEM - APPLEWOOD AND BRIER PARK SUBDIVISIONS

General Description:

In 1993, BPI's predecessor entity, the Public Utilities Commission of the City of Brantford [subsequently the Hydro-Electric Commission of the City of Brantford] initiated a ten year capital plan to be completed in 2003 to convert the existing 4 and 8 kV systems to more efficient 27 kV systems, which are BPI's current standard. These discretionary conversion projects were undertaken with the goals of improving reliability, reducing system losses and overall, improving customer satisfaction. Additionally, as part of the conversion program, distribution stations are decommissioned improving operational efficiency, reducing ongoing maintenance costs and reducing potential environmental impacts from PCB contamination.

BPI postponed the conversion program in 2001 in order to prudently manage cash flow resulting from its loss position in 1999 at the time that distribution rates were unbundled. The conversion program was resumed in 2006 with funding under a Board approved Tier 2 adjustment in BPI's 2006 electricity distribution rates.

The Applewood and Brier Park Subdivisions Voltage Conversion Project involved the rebuild of poles, towers and fixtures, overhead conductors and devices, underground conduit, conductors and devices and replacement of line transformers to convert from 4 kV to current 27.6 kV which is the prevalent standard of delivery in the City of Brantford. In addition, primary cables and submersible transformers were replaced to bring them to the 27 kV standard.

Name of Capital Project:	Applewood / Brier Park Conversion – Phase 4
Capital Project #	9
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	Convert from 4 kV to current 27.6 kV which is the prevalent standard of delivery in the City of Brantford.
Project Scope	Replace primary cables and replace submersible transformers with padmount transformers.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	June to October 2008
Actual Costs	$1,960,631
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was	Open competitive bidding based on yearly

contracted	approved, pre-qualified contractors.

Costs for the following 2007 projects were carried over into 2008;

- Spring Gardens - $100,639
- Coronation - $27,717

6. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS

General Description:

Annual rebuilds of existing lines and equipment discretionary projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers.

Annual rebuild requirements are identified through routine inspections of the distribution infrastructure. As a standard operating practice, routine inspections of one-third of the distribution infrastructure are undertaken annually and include pole testing, thermo graphic inspections of electrical connections and visual inspections of asset conditions.

Name of Capital Project	General Yearly Rebuilds
Capital Project #	10
USofA #	1830,1835,1840,1845,1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers. Pole replacements can also be a result of unexpected damage to existing poles (e.g. car accidents, etc.)
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.
Cost-benefit analysis, as applicable	N/A

Starting dates and in-service dates	2008
Actual Costs	$471,404
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

7. AM/FM AND GIS SYSTEM UPGRADE

General Description:

The existing software provider supporting the AM/FM Mapping and GIS System had ceased further research and development on the software currently utilized by BPI. This 2008 nondiscretionary capital project was required to migrate the Mapping and GIS system to a new vendor-supported platform – G-Technology 9.4.

Name of Capital Project	AM/FM and GIS System Upgrade
Capital Project #	11
USofA #	1980
Project Need & Purpose	Purchased G-Technology 9.4. from Intergraph to replace the existing FRAMME
Project Scope	Replaced legacy software. Installation & testing & verification of G-Technology 9.4.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2008
Actual Costs	$241,944
Who performed the work [in-house vs. contracted]	Data migration and setup done by Intergraph, testing and verification done by BPI.
Procurement method where work was contracted	Stayed with original supplier.

8. METERING

General Description:

The Meters and Instrument Transformer Capital Budget Pool are nondiscretionary projects and consist of:

- Replacement of meters that have failed; and
- Installation of new meters to service new customer connections

Name of Capital Project	Meters
Capital Project #	12
USofA #	1860
Project Need & Purpose	These meters and where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 367 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2008
Actual Costs	$229,050
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

9. REPLACEMENT OF VEHICLES

General Description:

BPI assesses all vehicle replacement on a case-by-case basis to determine the useful life of the vehicle while maintaining acceptable safety standards. There are discretionary but priority projects with a minimum guideline to replace light vehicles after 7 years and heavy vehicles after 10 years.

Name of Capital Project	Replacement of Vehicles

Capital Project #	13
USoA #	1930
Project Need & Purpose	Vehicle replacements required due to excessive mileage and/or expiry of service life.
Project Scope	BPI replaced the following 3 light vehicles with similar models. • Cube van with built-in generator purchased in 1994; • Light Vehicle purchased in 1999 with excessive mileage used by Operations (Chevy Blazer); and • Minivan with excessive mileage used for customer premise visits.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2008
Actual Costs	$165,750
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

10. RECOVERIES/CAPITAL CONTRIBUTIONS

General Description:

Grants paid by the municipality and Ministry of Transportation to offset the costs of overhead line relocations because of road infrastructure work. Contributions to system enhancement projects are determined by the economic evaluation model.

Description	**USofA**	**Actual Costs**
Grants and Capital Contributions	1995	($627,570)

2009 Capital Projects

1. NEW LINES AND EQUIPMENT

A general description for New Lines and Equipment is provided under Exhibit 2, Tab 3, Schedule 2, Page 2.

Name of Capital Project	Residential Secondary Services
Capital Project #	1
USofA #	1830,1835,1840,1845,1850,1855
Project Need and Purpose	To provide residential secondary services, from underground transformers to customers.
Project Scope	Enhancement, roll-ins comprising mainly of residential customer connections
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2009
Actual Costs	$112,524
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Line Extensions
Capital Project #	2
USofA #	1830, 1835, 1845
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, overhead portions of mostly general service customer connections and pole lines.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2009
Actual Costs	$206,127
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Underground Line Extensions
Capital Project #	3

USofA#	1840,1845
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, underground portions of mostly general service customer connections including cables and ducts
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2009
Actual Costs	$236,335
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Enhancement, all pole mount transformers for connection to residential and general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2009
Actual Costs:	$202,555
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	New Underground Transformers
Capital Project #	5
USofA #	1845, 1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, all padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2009

Actual Costs	$277,149
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

The following projects were completed in 2009:

- Secondary extension – 405 St. Paul Ave.
- Recloser - 60 Colborne St. West
- New Service – 347 Colborne St.
- New Service – Brantford Generation – Morrison Rd.
- Switch Install – Mohawk St. Pole # 5053
- New Service – Brantford Collegiate Institute – off of Jarvis St.
- New Service – 45 Albion St.
- New Service – Tim Hortons – 265 King George Rd.
- New Service – 40 Shellington Place
- New Service – Maddock – 50 Morrell St.
- New Service – 140 / 142 Brant Ave.
- New Service – 30 Craig St.
- New Service – 121 Darling St.

2. POWERLINE FEEDER UPGRADES

General Description:

Powerline Feeder Upgrades comprise of various essential and nondiscretionary builds. Projects include:

- Increase number of circuits into BPI's distribution territory to meet the potential for future demand;
- Install larger poles for future circuits.

Name of Capital Project:	Powerline Feeder (Francis St. to Municipal Station #2) – Phase 1
Capital Project #	6
USofA #	1830, 1835, 1845
Project Need and Purpose	Extended the existing single circuit feeder on Powerline Road from the Powerline Municipal Transformer Station at the North - West end of the City of Brantford to approximately 8km East. Also, 2 more feeders were added to feed customers in this area reducing burden from the existing Brantford transformer stations' overloaded feeders as well as cater to any new customers. This project also supports upgrade to the existing feeder to Brant County Power as an attachment to BPI owned poles.
Project Scope:	Project comprised of replacing existing poles to cover approximately 8 km length of the circuit extending from Powerline Municipal Transformer Station to the North-East end of the City of Brantford. The existing feeder (including Brant County Power owned circuit feeder) was upgraded to 556 aluminum wires, plus 2 new feeders were added for future loading needs.
# of Customer Attachments	N/A
Load	N/A
Cost-benefit analysis, as applicable	The alternative to extending this feeder was to build a 2nd Transformer Station (after Powerline Municipal Transformer Station in

	the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline Municipal Transformer Station which has the capacity to cater to the existing and future loading needs.
Starting dates and in-service dates	June to July 2009
Actual Costs	$353,641
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Through competitive bidding process

3. NEW SUBDIVISIONS AND TOWNHOMES

A general description for New Subdivisions and Townhomes is provided under Exhibit 2, Tab 3, Schedule 2, Page 5.

Name of Capital Project:	Wynfield West Ext. of Blackburn
Capital Project #	7
USofA #	1830, 1840, 1845
Project Need and Purpose	The 3 phase primary expansion was done for several reasons – it is a continuation of BPI's 3 phase backbone through the subdivision, the new switch is one of the backups for the new subdivision, and it was the 3 phase feed for the new school built in 2011 and the future church. When this feed was built there were no customers connected to it so no economic evaluation was performed. Now that the subdivision has expanded some of the costs for the feed will be used in current economic evaluations.
Project Scope	This was an underground 3 phase primary expansion from an existing switch on Conklin to a pad mounted switch on Blackburn in Wynfield West subdivision.
Number of Customer Attachments	Estimated connection of 170 subdivision units and 80 townhomes. Estimate based on developer and/or builder plans.
Cost-benefit analysis, as applicable	N/A

Starting dates and in-service dates	2009
Actual Costs	$1,654,016
Who performed the work [in-house vs. contracted]	The developer contracted with the City of Brantford, the Grand Erie District School Board for the feed on the new school. The school was not built until 2011.
Procurement method where work was contracted	N/A

4. SCADA & DISTRIBUTION AUTOMATION

A general description for SCADA and Distribution Automation is provided under Exhibit 2, Tab 3, Schedule 3, Page 7.

Name of Capital Project:	Recloser Installation on Colborne St. W.
Capital Project #	8
USofA #	1980
Project Need & Purpose:	Brant County Power is an embedded LDC on the Brantford 65M25 feeder. The Colborne St. W. recloser installation was required to minimize the effects of faults in the County seen by BPI customers. The recloser will isolate the downstream faulted feeder section while maintaining power for BPI customers upstream.
Project Scope	The recloser was purchased from G&W Electric complete with SEL 651R relay. Purchased SCADA radio and antenna. BPI completed a short circuit and protection study to determine settings for the recloser. The recloser settings were uploaded by BPI. The recloser was installed and commissioned by BPI and the SCADA radio was configured and installed by BPI.
Cost-benefit analysis, as applicable	The Colborne St. W recloser will isolate the feeder for downstream faults in Brant County Powers embedded service territory. This results in a significant reduction in outage time for BPI customers upstream.
Starting dates and in-service dates	2009
Actual Costs	$96,919
Who performed the work [in-house vs.	In-house

contracted]	
Procurement method where work was contracted	Sole source – G&W Electric.

5. CONVERSION OF LINES FROM 4 AND 8kV TO 27 kV SYSTEM – TRANQUILITY, ROSEWOOD, WYNDHAM HILLS, AVA RD, SIXTH AVE, & STRAWBERRY HILL CONVERSION

General Description:

In 1993, BPI's predecessor entity, the Public Utilities Commission of the City of Brantford [subsequently the Hydro-Electric Commission of the City of Brantford] initiated a ten year capital plan to be completed in 2003 to convert the existing 4 and 8 kV systems to more efficient 27 kV systems, which are BPI's current standard. These discretionary conversion projects were undertaken with the goals of improving reliability, reducing system losses and overall, improving customer satisfaction. Additionally, as part of the conversion program, distribution stations are decommissioned improving operational efficiency, reducing ongoing maintenance costs and reducing potential environmental impacts from PCB contamination.

BPI postponed the conversion program in 2001 in order to prudently manage cash flow resulting from its loss position in 1999 at the time that distribution rates were unbundled. The conversion program was resumed in 2006 with funding under a Board approved Tier 2 adjustment in BPI's 2006 electricity distribution rates.

The Tranquility, Rosewood, Wyndham, Ava Rd., Sixth Ave., Strawberry Hill Conversion involves the rebuild of poles, towers and fixtures, overhead conductors and devices, underground conduit, conductors and devices and replacement of line transformers.

Name of Capital Project:	Tranquility, Rosewood, Wyndham Hills, Ava Rd., Sixth Ave. & Strawberry Hill Conversion
Capital Project #	9
USofA #	1830, 1835, 1840, 1845, 1850

Project Need & Purpose:	Convert from 4 kV to current 27.6 kV which is the prevalent standard of delivery in the City of Brantford. This upgrade allowed BPI to improve the reliability to the customers connected through these older network pieces and reduce the number of potential outages. The majority of these installations have been upgraded and the remaining is expected to be identified through the new Asset Management Program. The monies set aside for these upgrades in 2011 and prior, were based on the general scope of work as determined through inspections of the sites and available feedback options to maintain power to the affected customers during the upgrade / change out process or as planned outages.
Project Scope	The project involved upgrading existing line sections on the main distribution network including replacing primary cables and submersible transformers to bring them to the 27.6 kV standard, and removing backyard lot pole lines. Upgrades to servicing feeds to industrial/commercial customers, from the older 8 kV/4 kV standard to the current 27.6 kV standard also took place.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2009
Actual Costs	$1,402,272
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors

6. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS

A general description for Annual Pole Replacements and General Rebuilds is provided under Exhibit 2, Tab 3, Schedule 2, and Page 10.

Name of Capital Project	General Yearly Rebuilds
Capital Project #	10
USofA #	1830,1835,1840,1845,1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and

	vaults, overhead or underground conductors and devices and line transformers. Pole replacements can also be a result of unexpected damage (e.g. car accidents, etc.)
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2009
Actual Costs	$512,324
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

7. TESTING OF G-TECHOLOGY VERSION 9.4

General Description:

BPI executed internal testing of G-Technology Version 9.4 that was an upgrade from the original AM/FM and GIS System upgrade that took place in 2008

Name of Capital Project	Testing of G-Technology Version 9.4
Capital Project #	11
USofA #	1980
Project Need & Purpose	Required to test software to detect and correct errors as a result of data migration from AM/FM to G-Technology version 9.4
Project Scope	Testing and verification of G-Technology 9.4.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2009
Actual Costs	$70,814
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

8. METERING

A general description for Metering is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	12
USoA #	1860
Project Need & Purpose	These meters and where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 238 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2009
Forecasted Costs	$349,517
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

9. REPLACEMENT OF VEHICLES

A general description for Replacement of Vehicles is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Replacement of Vehicles
Capital Project #	13
USoA #	1930
Project Need & Purpose	Vehicle replacements required due to excessive mileage and/or expiry of service life.
Project Scope	BPI replaced the following vehicles with a similar model. • Yard/Crane Truck purchased in 1987 was not big/heavy enough to lift larger padmounts – replacing alleviated crane rentals.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2009
Actual Costs	$312,919
Who performed the work [in-house vs.	In-house

contracted]	
Procurement method where work was contracted	Tender

10. RECOVERIES/CAPITAL CONTRIBUTIONS

A general description for Recoveries/Capital Contributions is provided under Exhibit 2, Tab 3, Schedule 2, Page 13.

Description	USofA	Actual Costs
Grants and Capital Contributions	1995	($745,257)

2010 Capital Projects

1. NEW LINES AND EQUIPMENT

A general description for New Lines and Equipment is provided under Exhibit 2, Tab 3, Schedule 2, Page 2.

Name of Capital Project	Residential Secondary Services
Capital Project #	1
USofA #	1830,1835,1840,1845,1850,1855
Project Need and Purpose	To provide residential secondary services from underground transformers to customers.
Project Scope	Expansion, roll-ins comprising mainly of residential customer connections.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2010
Actual Costs	$156,047
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Line Extensions
Capital Project #	2
USofA #	1830,1835, 1845
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, overhead portions of mostly general service customer connections and pole lines.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2010
Actual Costs	$354,061
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Underground Line Extensions
Capital Project #	3
USofA#	1840, 1845

Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, underground portions of mostly general service customer connections including cables and ducts.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2010
Actual Costs	$483,721
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	New Underground Transformers
Capital Project #	4
USofA #	1845,1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, all padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2010
Actual Costs	$593,583
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

The major servicing projects that were completed in 2010 include:

- New service: Gretzky Center – 254 North Park St., Fairview Dr.
- New Service – 54 Winnett St.
- New Pole – Madock – 50 Morell St.
- New Service – 71 Middleton St.
- Service relocation – Nelson St.
- New service – East Ave. (rear of 353 Colborne)
- New Secondary Service – Holiday Dr.
- New Service – 102 Dalhousie St.

- New line ext. – Brant County Ford – Lynden Rd.
- New Service – Alfred St. (from pole #16108)
- New Service – 23 Bury Court
- New Service – Laurier Building – 150 Dalhousie St.
- New Service – 299 Wayne Gretzky Parkway/Edmondson St.
- New Secondary Service & Pole – 148 Bodine Dr.
- Service Upgrade – 430 Hardy Rd.
- New Service – 170 North Park St.
- New Service – St. John's College – 80 Paris Rd.
- New Transformer and Switch – 195 Henry St.(Bosworth Crt.)
- New Service – 347 Erie Ave.
- New Service – 57 Copernicus
- New Service – 300 King George Rd

2. POWERLINE FEEDER UPGRADES

A general description for Powerline Feeder Upgrades is provided under Exhibit 2, Tab 3, Schedule 2, Page 17.

Name of Capital Project:	Powerline Feeder (Powerline Municipal Transformer Station to Francis St.) – Phase 2
Capital Project #	5
USofA #	1830,1835,1845
Project Need and Purpose	Extended the existing single circuit feeder on Powerline Road from the Powerline Municipal Transformer Station at the North - West end of the City of Brantford to approximately 8km East. 2 more feeders were also added to feed customers in this area reduce burden from the existing Brantford transformer stations' overloaded feeders as well as cater to any new customers. This project also supports upgrade to the existing feeder to Brant County Power as an attachment to BPI owned poles.
Project Scope:	Project comprised of replacing existing poles to cover approximately .8km length of the

	circuit extending from Powerline Municipal Transformer Station to the North-East end of the City of Brantford. The existing feeder (including Brant County Power owned circuit feeder) was upgraded to 556Al standard, plus 2 new feeders were added for future loading needs.
# of Customer Attachments	N/A
Cost-benefit analysis, as applicable	The alternate to extending this feeder was to build a 2nd Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline MTS which has the capacity to cater to the existing and future loading needs.
Starting dates and in-service dates	2010
Actual Costs	$524,514
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Through competitive bidding process

3. NEW SUBDIVISIONS AND TOWNHOMES

A general description for New Subdivisions and Townhomes is provided under Exhibit 2, Tab 3, Schedule 2, Page 5.

Name of Capital Project:	New Subdivisions & Townhomes
Capital Project #	6
USofA #	1830,1840,1845
Project Need and Purpose	Work is required to connect new sub-divisions and new townhomes.

Project Scope	The project consists of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure. The budget for this capital pool is based on historical data as well as specific information provided by developers, electricians and engineering companies.
# of Customer Attachments	Estimated connection of 350 subdivision units and 40 townhomes. Estimate based on developer and/or builder plans.
Load	Estimated as 730 kwh per lot per year
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2010
Actual Costs	$265,408
Who performed the work [in-house vs. contracted]	Majority of the work is performed by building contractors as subcontractors to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

Projects completed in 2010 include:

- Grand Valley Trails
- Dufferin St Condos
- North Park Rd. Condos

4. SCADA & DISTRIBUTION AUTOMATION

A general description for SCADA and Distribution Automation is provided under Exhibit 2, Tab 3, Schedule 3, Page 7.

Name of Capital Project:	SCADA System Upgrade to Windows
Capital Project #	7
USofA #	1980

Project Need & Purpose:	BPI’s original SCADA system utilized a Virtual Memory Platform (VMS). BPI’s SCADA vendor ended new product development for SCADA VMS in 2009. VMS hardware was also very difficult to source. With the development of Smart Grid and the need for system interoperability, it was decided to upgrade to the new Windows based, dual redundant SCADA system.
Project Scope	Purchased new Windows dual redundant SCADA system from Survalent. Installation and commissioning was completed with the assistance of Survalent and AESI (BPI's SCADA consultant at the time.) SCADA Manager training for BPI staff at Suravalent's head office (1 week.)
Cost-benefit analysis, as applicable	BPI's original VMS SCADA system would no longer be supported by the SCADA vendor. Software development ended from the SCADA vendor. Sourcing VMS hardware was becoming very difficult. There was need for a SCADA system that would interface with other systems and was more intuitive for the end user.
Starting dates and in-service dates	2010
Actual Costs	$246,707
Who performed the work [in-house vs. contracted]	In-house and contracted
Procurement method where work was contracted	Sole source provider - Survalent Technology

5. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS

A general description for Annual Pole Replacements and General Rebuilds is provided under Exhibit 2, Tab 3, Schedule 2, Page 10.

Name of Capital Project	General Yearly Rebuilds
Capital Project #	8
USofA #	1830, 1835, 1840, 1845, 1850

Project Need & Purpose	Annual rebuilds of existing lines and equipment projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers. Pole replacements can also be a result of unexpected damage to existing poles (e.g. car accidents, etc.)
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year but based on historic spends.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2010
Actual Costs	$432,011
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

1 **6. BRANTWOOD PARK REHABILITATION**

Name of Capital Project	Brantwood Park – Phase 1
Capital Project #	9
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose	Rehabilitation of the distribution system including replacement of submersible transformers and relocation of underground structures.
Project Scope	Replace primary cables and change submersible transformers to padmount transformers.
Cost-benefit analysis, as applicable	Supported by Asset Management Program
Starting dates and in-service dates	June to November 2010
Actual Costs	$1,537,546
Who performed the work [in-house vs. contracted]	Contracted – Civil, In-house – Electrical.
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

7. METERING

A general description for Metering is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	10
USofA #	1860
Project Need & Purpose	These meters and where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 457 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2010
Actual Costs	$355,369
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

8. WHOLESALE METERING (Brantford TS)

General Description:

As a compliance requirement to meet Measurement Canada and IESO requirements, wholesale metering for the BPI delivery points at the Brantford Transformer Station owned by Hydro One needed to be upgraded and instrument transformers upgraded before the end of 2009. This was a discretionary project. Hydro One prepared engineering estimates in 2009.

Name of Capital Project	Installation of Wholesale Meters – Brantford Transformer Station
Capital Project #	11
USofA #	1860

Project Need & Purpose	Need to maintain compliance with Measurement Canada (MC) and Independent Electricity System Operator (IESO) requirements for metering of wholesale electricity delivery points.
Project Scope	Detailed scope of work and cost estimate by Hydro One.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2008 (start), 2010 (in-service)
Actual Costs	$769,365
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	There were no tender documents issued as Hydro One was the only authorized service provider for the instrument transformer replacement work inside the Brantford Transformer Station. BPI used its existing wholesale Meter Service Provider for the metering and communications work.

9. REPLACEMENT OF VEHICLES

A general description for Replacement of Vehicles is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Replacement of Vehicles
Capital Project #	12
USofA #	1930
Project Need & Purpose	Vehicle replacements required due to excessive mileage and/or expiry of service life.
Project Scope	BPI replaced the following vehicles with a similar model. • Mid-size pickup (1999) due to excessive mileage • Single Bucket Truck (2000) involved in major accident and needs substantial repairs • Mid-size Meter Van (1996) due to

	excessive mileage replaced with a smaller Transit Connect for fuel efficiency • Open Stake Trailer (1974) replaced with Covered Dump Trailer – Highway Traffic Act requires covered trailer if transporting materials.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2010
Actual Costs	$248,832
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

10. RECOVERIES/CAPITAL CONTRIBUTIONS

A general description for Recoveries/Capital Contributions is provided under Exhibit 2, Tab 3, Schedule 2, Page 13.

Description	**USofA**	**Actual Costs**
Grants and Capital Contributions	1995	($196,588)

2011 Capital Projects

1. NEW LINES & EQUIPMENT

A general description for New Lines and Equipment is provided under Exhibit 2, Tab 3, Schedule 2, Page 2.

Name of Capital Project	Residential Secondary Services
Capital Project #	1
USofA #	1830,1835,1840,1845,1850,1855
Project Need and Purpose	To provide residential secondary services from underground transformers to customers.
Project Scope	Expansion - roll-ins comprising mainly of residential customer connections.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2011
Actual Costs	$118,230
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Line Extensions
Capital Project #	2
USofA #	1835
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - overhead portions of mostly general service customer connections and pole lines.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2011
Actual Costs	$352,871
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Underground Line Extensions
Capital Project #	3
USofA#	1845

Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - underground portions of mostly general service customer connections including cables and ducts.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2011
Actual Costs	$327,251
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - all pole mount transformers for connection to residential and general service customers.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2011
Actual Costs	$83,450
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	New Underground Transformers
Capital Project #	5
USofA #	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - all padmount transformers for connection mainly to general service customers.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2011
Actual Costs	$508,860

Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

The major servicing projects that were completed in 2011 include:

- 225 Colborne St.
- New Laurier University building on Charlotte St.
- 65 George St.
- Blastech
- 50 Iroquois St.
- 410 Hardy Rd.
- Bail Mini Storage - Henry St.
- New school - 365 Blackburn Dr.
- 575 Rark Rd. N.
- 52 Pontiac St. (Transformer relocation)
- 470 Colborne St. W.
- 28 Plant Farm Blvd.
- 34 Norman St.
- 1 Alfred St.
- 46 Empey St.
- 26 Brantwood Park Rd.
- 43 Plant Farm Blvd.
- 300 King George Rd.(New transformer feed)

2. POWERLINE FEEDER UPGRADES

A general description for Powerline Feeder Upgrades is provided under Exhibit 2, Tab 3, Schedule 2, Page 17.

Name of Capital Project:	Powerline Feeder (Powerline Municipal Tranformer Station to Francis St.) – Phase 3

Capital Project #	6
USofA#	1830,1835,1840, 1845, 1850
Project Need and Purpose	To extend the existing single circuit feeder on Powerline Road from Powerline Municipal Transformer Station at the North - West end of the City of Brantford to approximately 8km East and add 2 more feeders. The extension will reduce burden from the existing Brantford transformer station overloaded feeders as well as cater to any new customers. (The burden is the loading of the feeder from Mary Street and extending it to feed Powerline area customers. With the extra load and distance from Mary St. station, there would be low voltage issues.) This project will also support an upgrade to the existing feeder to Brant County Power as an attachment to BPI owned poles.
Project Scope:	The project comprises of replacing existing poles to cover approximately 8km length of the circuit extending from Powerline Municipal Transformer Station to the North-East end of the City of Brantford. The existing feeder (including Brant County Power owned circuit feeder) will be upgraded to 556 aluminum wires, plus 2 new feeders will be added for future loading needs. This involved re-routing some of the poles from behind homes on private property to the front of the homes for ease of construction and future maintenance and negotiating land easements with property owners as well. The project is being carried out in phases each year and each phase is identified and treated as a separate project. The expected completion is in 2016.
# of Customer Attachments	N/A
Load	N/A
Cost-benefit analysis, as applicable	The alternate to extending this feeder was to build a second Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford.

	The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline Municipal Transformer Station.
Starting dates and in-service dates	2011 (Phase 3) Oct. 2011 & Dec. 2011
Actual Costs	$489,849
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Through competitive bidding process

3. NEW SUBDIVISIONS & TOWNHOMES

A general description for New Subdivisions and Townhomes is provided under Exhibit 2, Tab 3, Schedule 2, Page 5.

Name of Capital Project:	Wynfield West – 2A + 2B – Stage 1
Capital Project #	7
USofA #	1830, 1835, 1840, 1845, 1850
Project Need and Purpose	Work is required to connect new sub-divisions and new townhomes.
Project Scope	The project comprises of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure. The budget for this capital pool is based on historical data as well as specific information provided by developers, electricians and engineering companies.
Number of Customer Attachments	Estimated connection of 339 subdivision units and 39 townhomes. Estimate based on developer and/or builder plans.
Load	Estimated as 730 kwh per lot per year
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2011
Actual Costs	$328,556
Who performed the work [in-house vs.	The majority of the work is performed by

contracted]	building contractors as subcontractors to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

While no individual project undertaken in 2011 exceeded the materiality threshold, examples of projects in the Capital Budget Pool include:

- Elizabeth St.

4. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS – ASSET MANAGEMENT SYSTEM

A general description for Annual Pole Replacements and General Rebuilds is provided under Exhibit 2, Tab 3, Schedule 2, Page 11.

Name of Capital Project	General Yearly Rebuilds
Capital Project #	8
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers. Pole replacements can also be a result of unexpected damage to existing poles (e.g. car accidents, etc.)
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2011
Actual Costs	$613,691
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

5. BRANTWOOD/DUNSDON REBUILD

General Description:

This project included rehabilitation of the distribution system including replacement of submersible transformers, relocation of underground structures, replacing primary cables and changing submersible transformers to padmount transformers.

Name of Capital Project	Brantwood/Dunsdon Rebuild
Capital Project #	9
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose	Rehabilitation of the distribution system including replacement of submersible transformers and relocation of underground structures.
Project Scope	Replace primary cables and change submersible transformers to padmount transformers.
Cost-benefit analysis, as applicable	Supported by Asset Management Program
Starting dates and in-service dates	May 2011 – Sept. 2011
Actual Costs	$1,468,877
Who performed the work [in-house vs. contracted]	Contracted – Civil, In-house- Electrical
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

6. ASSET MANAGEMENT CONSULTANCY AND SOFTWARE

General Description:

BPI engaged UEM to develop a multi-year Asset Management Program in 2010. The first year objective to deliver a capital plan in support of rate rebasing application was achieved by the end of 2011.

This involved individual work assignments undertaken by BPI staff and by UEM as well as through group workshops with the Asset Management team.

Through this work BPI developed strategies for level of service, risk, performance monitoring, asset lifecycles and decision parameters. These strategies formed the basis for modifying UEM's proprietary tool ODM to meet BPI's specific needs. This work also provided an insight on the shortcomings in current data, systems and processes that were deemed essential for maintaining a sustainable AMP. UEM provided a report to BPI that provided results on the first year of the project and their recommendation to overcome these gaps in data and business process.

Name of Capital Project	Asset Management Consultancy and Software
Capital Project #	10
USofA #	1925
Project Need & Purpose	In the course of the 2008 rate application, BPI committed to investigate Asset Management after identifying an internal need for a risk focused approach to asset management and to develop a sustainable long term program to better manage its assets and better inform the capital plan and budgets for timely asset replacement needs.
Project Scope	The scope covers all activities outlined in the 5-year asset management plan involving consultancy work and supervision by UEM, GIS related upgrades and new software installation by Intergraph (GIS vendor) and UEM as well as individual data collection, assimilation, storage and processing by BPI staff and City of Brantford IT Services. This includes but is not limited to modifying parameters of gap analysis and model data collection.
Cost-benefit analysis, as applicable	The alternate to having a consultant with expertise in the field and working with BPI staff and existing systems, was to purchase expensive off-the-shelf software as well as paying to modify it and integrate with the existing systems and business processes. This would be far more costly, time consuming and resource intensive.
Starting dates and in-service dates	2011 project tasks as per the project plan
Actual Costs	$219,196

Who performed the work [in-house vs. contracted]	The work will primarily be performed by BPI staff in consultation with UEM as well GIS related upgrades by the vendor (Intergraph). BPI will enter into single source agreements with UEM annually based on the performance of the previous years and work by Intergraph will be through the service level agreement with them to support the existing GIS platform.
Procurement method where work was contracted	Sole source – UEM as approved by BPI Board of Directors.

7. UPGRADE TO G-TECHNOLOGY VERSION 10

General Description:

As part of Intergraph's upgrade plan, Intergraph informed BPI that BPI would need to upgrade from G-Technology version 9.4 to G-Technology version 10. This nondiscretionary project was required as Intergraph ceased support for version 9.4.

Name of Capital Project	AM/FM and GIS System Upgrade to G-Technology Version 10/GeoMedia
Capital Project #	11
USofA #	1925
Project Need & Purpose	Purchased software. from Intergraph, and replaced soon to be unsupported software.
Project Scope	Migrate the data from FRAMME to G-Technology making G-Technology's interface to function as it did in FRAMME.
Cost-benefit analysis, as applicable	Stayed with original supplier.
Starting dates and in-service dates	2011
Actual Costs	$75,249
Who performed the work [in-house vs. contracted]	Data migration and setup done by Intergraph, testing and verification done by BPI.
Procurement method where work was contracted	Sole source provider – Intergraph.

8. METERING

A general description for Metering is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	12
USofA #	1860
Project Need & Purpose	These meters and where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 339 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2011
Actual Costs	$150,239
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

9. WHOLESALE METERING (Brantford TS)

A general description for Wholesale Metering (Brantford TS) is provided under Exhibit 2, Tab 3, Schedule 2, Page 32.

Name of Capital Project	Installation of Wholesale Meters – Brantford Transformer Station
Capital Project #	13
USofA #	1860
Project Need & Purpose	Need to maintain compliance with Measurement Canada (MC) and Independent Electricity System Operator (IESO) requirements for metering of wholesale electricity delivery points.
Project Scope	Detailed scope of work and cost estimate by Hydro One.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2011
Actual Costs	$26,781 (carried over from 2010)
Who performed the work [in-house vs. contracted]	Contracted

Procurement method where work was contracted	There were no tender documents issued as Hydro One was the only authorized service provider for the instrument transformer replacement work inside the Brantford Transformer Station. BPI used its existing wholesale Meter Service Provider for the metering and communications work.

10. REPLACEMENT OF VEHICLES

A general description for Replacement of Vehicles is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Replacement of Vehicles
Capital Project #	14
USofA #	1930
Project Need & Purpose	Vehicle replacements required due to excessive mileage and/or expiry of service life.
Project Scope	BPI replaced the following vehicle with a similar model. ➢ One line truck (2003) due to substantial repairs required.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2011
Actual Costs	$309,767
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

11. RECOVERIES/CAPITAL CONTRIBUTIONS

A general description for Recoveries/Capital Contributions is provided under Exhibit 2, Tab 3, Schedule 2, Page 13.

Description	**USofA**	**Actual Costs**
Grants and Capital Contributions	1995	($265,560)

2012 Bridge Year Capital Projects:

1. NEW LINES AND EQUIPMENT

A general description for New Lines and Equipment is provided under Exhibit 2, Tab 3, Schedule 2, Page 2.

Name of Capital Project	Residential Secondary Services
Capital Project #	1
USofA #	1830,1835,1840,1845,1850,1855
Project Need and Purpose	To provide residential secondary services from underground transformers to customers.
Project Scope	Expansion - roll-ins comprising mainly of residential customer connections
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2012
Actual Costs	$134,156
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Line Extensions
Capital Project #	2
USofA #	1835
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - overhead portions of mostly general service customer connections and pole lines.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2012
Actual Costs	$179,453
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Underground Line Extensions
Capital Project #	3
USofA#	1845

Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion- underground portions of mostly general service customer connections including cables and ducts
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2012
Actual Costs	$351,833
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - all pole mount transformers for connection to residential and general service customers.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2012
Actual Costs	$156,725
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project:	New Underground Transformers
Capital Project #	5
USofA #	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion, all padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2012

Actual Costs	$210,587
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

The major servicing projects that were completed in 2012 include:

- 45 Adams Blvd
- 605 West St.
- 53 Craig St.
- 215 Greenwich St.
- 53 Dalhousie St.
- 72 Copernicus Blvd.
- 210 Hachborn Rd.
- 378 Elgin St.
- Henry St. (Leons Store)
- 545 Mohawk St.
- 35 Roy Blvd.
- 11 Spalding Dr.
- 60 Bury Crt.
- Woodman School, Grey St.
- 7 Oakley St.
- Clarence St. (Beer Store)
- 360 Brock St.
- Wood St. – St. Pius (new school)
- 76 Middleton Rd.

2. POWERLINE FEEDER UPGRADES

A general description for Powerline Feeder Upgrades is provided under Exhibit 2, Tab 3, Schedule 2, Page 17.

Name of Capital Project:	Powerline Feeder Upgrades –(Powerline Municipal Transformer Station to Francis St.) - Phase 4
Capital Project #	6
USofA #	1830,1835,1840, 1845, 1850
Project Need and Purpose	To extend the existing single circuit feeder on Powerline Road from Powerline Municipal Transformer Station at the Northwest end of the City of Brantford to approximately 8km East and add 2 more feeders. The extension will reduce burden from the existing Brantford transformer station overloaded feeders as well as cater to any new customers. (The burden is the loading of the feeder from Mary Street and extending it to feed Powerline area customers. With the extra load and distance from Mary St. station, there would be low voltage issues.) This project will also support an upgrade to the existing feeder to Brant County Power as an attachment to BPI owned poles.
Project Scope	The project consists of replacing existing poles to cover approx. 8km length of the circuit extending from Powerline Municipal Transformer Station to the North-East end of the city. The existing feeder (including Brant County Power owned circuit feeder) will be upgraded to 556 aluminum wire standard, plus 2 new feeders will be added for future loading needs. This involved re-routing some of the poles from behind homes on private property to the front of the homes for ease of construction and future maintenance, and negotiating land easements with property owners as well. The project is being carried out in phases each year and each phase is identified and treated as a separate project. The expected completion is in 2016.
Cost-benefit analysis, as applicable	The alternate to extending this feeder was to build a second Transformer Station (after

	Powerline Municipal Transformer Station) in the North-East end of the City. The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline Municipal Transformer Station which has the capacity to cater to existing and future loading needs.
Starting dates and in-service dates	(Phase 4 – Feb & Dec. 2012)
Actual Costs	$692,218
Who performed the work [in-house vs. contracted]	Contracted
Procurement method where work was contracted	Through competitive bidding process

3. NEW SUBDIVISIONS & TOWNHOMES

A general description for New Subdivisions and Townhomes is provided under Exhibit 2, Tab 3, Schedule 2, Page 5.

Name of Capital Project:	Wynfield West (Phase 2A & 2B) – Stage 2
Capital Project #	7
USofA #	1845
Project Need and Purpose	Work is required to connect new sub-divisions and new townhomes.
Project Scope	The project comprises of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure.
Number of Customer Attachments	Estimated connection of 150 subdivision units and 50 townhomes. Estimate based on developer and/or builder plans.
Load	Estimated as 730 kwh per lot per year
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2012
Actual Costs	$841,872
Who performed the work [in-house vs. contracted]	Majority of the work is performed by building contractors as subcontractors to the consulting engineer of the developer. Electrical cabling

	and energization work is performed in-house
Procurement method where work was contracted	N/A

4. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS – ASSET MANAGEMENT SYSTEM

A general description for Annual Pole Replacements and General Rebuilds is provided under Exhibit 2, Tab 3, Schedule 2, and Page 10.

Name of Capital Project	General Yearly Rebuilds
Capital Project #	8
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers. Pole replacements can also be a result of unexpected damage to existing poles (e.g. car accidents, etc.)
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on historic spends.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2012
Actual Costs	$660,709
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

Name of Capital Project	Lynden Hill Estates
Capital Project #	9
USofA #	1830,1835, 1840, 1845, 1850
Project Need & Purpose	Replace aging cables and remove submersible transformers to reduce / mitigate asset related risk and potential power outages.

Project Scope	Replace primary cables and change submersible transformers to padmount transformers.
Cost-benefit analysis, as applicable	Supported by Asset Management Program – 2012
Starting dates and in-service dates	Jun e to October 2012
Actual Costs	$1,096,019
Who performed the work [in-house vs. contracted]	Contracted – Civil, In-house - Electrical
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors

5. ASSET MANAGEMENT CONSULTANCY & SOFTWARE

General Description:

BPI engaged UEM to develop a multi-year Asset Management Program in 2010. The first year objective, to deliver a capital plan in support of a rate rebasing application, was achieved by the end of 2011.

BPI in consultation with UEM developed a plan of action in 2012 and work was started to execute the same, some of the key objectives which were achieved in 2012 included:

- Developing life-cycle models for assets;
- Updating the capital projects with new inspection records;
- Several modifications to the GTech and GIS platform to support the ongoing data collection, associations and processing; and
- Putting in place a training program for Operations staff to maintain consistency in inspection records.

Name of Capital Project	Asset Management Consultancy and Software
Capital Project #	10
USofA #	1925

Project Need & Purpose	In the course of the 2008 rate application, BPI committed to investigate Asset Management after identifying an internal need for a risk focused approach to asset management and to develop a sustainable long term program to better manage BPI's assets and better inform the capital plan and budgets for timely asset replacement needs.
Project Scope	The scope covers all activities outlined in the 5-year Asset Management Plan involving consultancy work and supervision by UEM, GIS related upgrades and new software installation by Intergraph (GIS vendor) and UEM as well as individual data collection, assimilation, storage and processing by BPI staff and City IT Services. This includes but is not limited to modifying parameters of gap analysis and model data collection.
Cost-benefit analysis, as applicable	The alternate to having a consultant with expertise in the field and working with BPI staff and existing systems, was to purchase expensive off-the-shelf software as well as paying to modify it and integrate with the existing systems and business processes, which is far more costly, time consuming and resource intensive.
Starting dates and in-service dates	2012 project tasks as per the project plan
Actual Costs	$230,987
Who performed the work [in-house vs. contracted]	The work will primarily be performed by BPI staff in consultation with UEM as well GIS related upgrades by the vendor (Intergraph). BPI will enter into single source agreements with UEM annually based on the performance of the previous years and work by Intergraph, will be through the service level agreement with them to support the existing GIS platform
Procurement method where work was contracted	Sole source provider – UEM as approved by the Board of Directors.

6. REPLACEMENT OF VEHICLES

A general description for Replacement of Vehicles is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Replacement of Vehicles
Capital Project #	11
USofA #	1930
Project Need & Purpose	Vehicle replacements required due to excessive mileage and/or expiry of service life.
Project Scope	BPI replaced the following vehicle with a similar model. • One large cube van (2002) with smaller cube van due to substantial repairs required.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2012
Actual Costs	$123,836
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

7. OFFICE FURNITURE & COMPUTER EQUIPMENT

General Description:

In 2012 BPI Finance moved from 220 Colborne St. (Customer Service) to 84 Market (Administration Offices) to streamline work flow and communication. This move resulted in the need for office furniture to accommodate Finance staff. In addition, due to the transfer of employees from the City of Brantford to BPI, computer hardware was purchased from the City - netbook value of hardware for those who were transferred to BPI at the time - value of the Daffron server (CIS system) was transferred from the City to BPI. iPads were also purchased for BPI Board members.

Name of Capital Project	Office Furniture & Computer Equipment
Capital Project #	12
USofA #	1980
Project Need & Purpose	Computer hardware and furniture needed to accommodate City employee transfer to BPI, Finance's physical relocation and Board

	member efficiency.
Project Scope	Purchase of desks and cabinets for Finance offices, Computer hard drives, monitors, 4 iPads and Daffron Server.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2012
Actual Costs	$106,553
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	RFQ

8. METERING

A general description for Metering is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	13
USofA #	1860
Project Need & Purpose	These meters and where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 261 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2012
Actual Costs	$129,614
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

9. RECOVERIES/CAPITAL CONTRIBUTIONS

General Description:

Grants paid by the municipality and Ministry of Transportation to offset the costs of overhead line relocations because of road infrastructure work. Contributions to system enhancement projects are determined by the economic evaluation model.

Description	**USofA**	**Actual Costs**
Grants and Capital Contributions	1995	($605,551)

2013 Test Year Proposed Capital Projects

Preamble

BPI's total net capital budget for the 2013 Test Year is forecasted to be $3,440,160

1. NEW LINES AND EQUIPMENT

A general description for New Lines and Equipment is provided under Exhibit 2, Tab 3, Schedule 2, Page 2.

The budget for this capital pool is based on historical data as well as specific information provided by developers, electricians and engineering companies. Some projects have been completed to date however; all costs included are forecasts for the total year.

New Lines and Equipment Capital Projects comprise the following components:

Name of Capital Project	Residential Secondary Services
Capital Project #	1
USofA #	1830,1835,1840,1845,1850,1855
	To provide residential secondary services from underground transformers to customers.
Project Scope	Expansion - roll-ins comprising mainly of residential customer connections.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2013
Forecasted Costs	$110,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Line Extensions
Capital Project #	2
USofA #	1835
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.

Project Scope	Expansion - overhead portions of mostly general service customer connections and pole lines.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2013
Forecasted Costs	$265,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Underground Line Extensions
Capital Project #	3
USofA#	1845
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - underground portions of mostly general service customer connections including cables and ducts.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2013
Forecasted Costs	$280,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Name of Capital Project	New Overhead Transformers
Capital Project #	4
USofA#	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - all pole mount transformers for connection to residential and general service customers.
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2013
Forecasted Costs	$45,000
Who performed the work [in-house vs.	In-house

contracted]	
Procurement method where work was contracted	N/A

Name of Capital Project:	New Underground Transformers
Capital Project #	5
USofA #	1850
Project Need and Purpose	To provide secondary and primary services from overhead and underground transformers to customers.
Project Scope	Expansion - all padmount transformers for connection mainly to general service customers
Cost-benefit analysis, as applicable	New connections (nondiscretionary)
Starting dates and in-service dates	2013
Forecasted Costs	$360,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

Projects completed to date in 2013 include;

- 54 Spalding Dr
- 159 Mary St
- 627 Park Rd N
- 422 Grey St
- 81 Elgin St (Fit)

2. POWERLINE FEEDER UPGRADES

A general description for Powerline Feeder Upgrades is provided under Exhibit 2, Tab 3, Schedule 2, Page 17.

Name of Capital Project:	Powerline Feeder Upgrades (Powerline Municipal Transformer Station to Francis St.) – Phase 5
Capital Project #	6
USofA #	1830,1835,1840, 1845, 1850

Project Need & Purpose:	To extend the existing single circuit feeder on Powerline Road from Powerline Municipal Transformer Station at the North - West end of the City of Brantford to approximately 8 km East and add 2 more feeders. The extension will reduce burden from the existing Brantford transformer station overloaded feeders as well as cater to any new customers. (The burden is the loading of the feeder from Mary Street and extending it to feed Powerline area customers. With the extra load and distance from Mary St. station, there would be low voltage issues.) This project will also support an upgrade to the existing feeder to Brant County Power as an attachment to BPI owned poles.
Project Scope	The project consists of replacing existing poles to cover approximately 8km length of the circuit extending from Powerline Municipal Transformer Station to the North-East end of the City of Brantford. The existing feeder (including Brant County Power owned circuit feeder) will be upgraded to 556Al standard, plus 2 new feeders will be added for future loading needs. This involved re-routing some of the poles from behind homes on private property to the front of the homes for ease of construction and future maintenance, and negotiating land easements with property owners. The project is being carried out in phases each year and each phase is identified and treated as a separate project. The expected completion is in 2016.
Cost-benefit analysis, as applicable	The alternate to extending this feeder was to build a second Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to extending new circuits and upgrading existing pole lines from the Powerline Municipal Transformer Station.
Starting dates and in-service dates	April – May 2013 (Phase 5)

Forecasted Costs	$450,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

3. NEW SUBDIVISIONS & TOWNHOMES

A general description for New Subdivisions and Townhomes is provided under Exhibit 2, Tab 3, Schedule 2, Page 5.

Name of Capital Project:	Wynfield West 3 – Phase 1
Capital Project #	7
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	Work is required to connect new sub-divisions and new townhomes.
Project Scope	The project consists of supply and installation of new underground cable, conduit, transformers, switches and structures to supply customers in the new development. This also includes installation of supply points on the distribution system to connect to and energize the new infrastructure.
Number of Customer Attachments	Estimated connection of 129 subdivision units and 65 townhome units. Estimate based on developer and/or builder plans.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2013
Forecasted Costs	$446,100
Who performed the work [in-house vs. contracted]	The majority of the work is performed by building contractors as subcontractor to the consulting engineer of the developer. Electrical cabling and energization work is performed in-house.
Procurement method where work was contracted	N/A

4. SCADA AND DISTRIBUTION AUTOMATION

A general description for SCADA and Distribution Automation is provided under Exhibit 2, Tab 3, Schedule 3, Page 7.

Development work to be undertaken in 2013 includes:

Name of Capital Project:	SCADA and Distribution Automation
Capital Project #	8
USofA #	1835
Project Need & Purpose:	SCADA Repeater Radio Installation Expansion of BPI’s SCADA radio network. This includes installation of a repeater radio at the Brantford General Hospital that will extend the SCADA radio network across the entire City of Brantford. 27.6 kV Recloser Installation This project will improve customer reliability. The recloser will be installed at the mid-way point of a feeder and will automatically sense downstream faults and isolate/sectionalize the line as required. Upstream customers between the feeder breaker and the recloser will not experience an outage as they would have without the recloser. Outage time to BPI's customers will be reduced. The recloser will be connected to BPI's SCADA and will provide real time voltage, current, real and reactive power and power quality information that would not be available otherwise. **Relocate SCADA HOSTA Server** Relocate to a secure location and have network connectivity with the backup HOSTB server. Due to department relocations, the HOSTA server is now situated within BPI office space. The SCADA servers are the main components of BPI's SCADA system. **ICCP Holdoffs via SCADA**

	When Operations requires a hold off from a Hydro One supplied feeder a phone call is required to the OGCC in Barrie. It can take up to ten minutes to receive a response from Hydro One which results in delays on BPI's end. One phone call is required to obtain a hold off and one phone call is required to surrender a hold off. **SCADA and Distribution Automation Contingency Funds** BPI's SCADA system contains several components such as computer servers, communication systems (radio, Ethernet, fibre) and automated field devices. Failure of any of these systems or devices will require immediate replacement.
Project Scope	**Repeater Radio Installation:** • Contractor to install and test the antenna on the mask at the hospital. • Configure repeater radio settings and test using head end radio software. **27.6 kV Recloser Installation:** • Determine the feeder with lower than desirable reliability indicators; • Establish the location for the recloser and coordinate the design with Engineering.; • Complete protection study to determine protection settings of the recloser; • BPI crews to install the recloser; • SCADA radio install, configure and test; • Update SCADA system with new DNP data from the recloser; • Update SCADA Worldview HMI with new screen for recloser monitoring/control. Test controls from SCADA. **Relocate SCADA HOSTA Server:** • Relocate HOSTA server to Powerline

	Municipal Transformer Station; • Install two new SonicWall firewalls and configure link between HOSTA (PMTS) and HOSTB (84 Market St.) using fibre point-to-point connection; • Test new network routing configuration for all data traffic between HOSTA and HOSTB, including ICCP data from Hydro One's Ontario Grid Control Centre (OGCC); • Repurpose existing SonicWall firewall to route SCADA radio DNP data over Corporate LAN from Operations Centre to SCADA servers; • Migrate PMTS radio communications into HOSTA SCADA server via Ethernet; • Remove Bell line between Powerline Municipal Transformer Station and Hydro One's Middleport station; • Migrate data required by Hydro One into HOSTA and route data through ICCP link to Hydro One's OGCC. **ICCP Holdoffs via SCADA** • Configure ICCP hold off feature in BPI SCADA system; • Modify SCADA firewall rules and test data flow; • Create new icons in SCADA HMI interface to allow for push button request of hold off from Hydro One; • Coordinate with Hydro One to test hold off feature. **SCADA and Distribution Automation Contingency Funds** • Replacement of SCADA equipment due to failure.
Cost-benefit analysis, as applicable	All projects and alternative option costs were considered with cost savings a priority.
Starting dates and in-service dates	2013
Forecasted Costs	$150,000
Who performed the work [in-house vs. contracted]	In-house/contracted

Procurement method where work was contracted	RFQ

5. CAPACITOR STUDY / INSTALLATION OF LINE BANKS

General Description:

At the time of building the PMTS in 2005, the IESO wanted BPI to install capacitor banks at the Transformer Station to ensure that the Power Factor was not below 95%. A study was done by BPI's consultant to determine if the capacitor installation could be delayed without compromising the power factor requirements, allowing BPI to defer the substantial investment on Transformer Station capacitors. The study indicated that there was no immediate need for the capacitors and they could possibly be delayed to 2015. BPI decided to perform this study again to see if the capacitors were required in 2015 or they could be delayed again. If BPI does need the capacitors in 2015, there will be a need to start this project as early as possible because of the long lead time required for design, procurement, installation and administrative & financial coordination with various stakeholders including Brant County Power, IESO and Hydro One. In addition, this study would review the distribution system as a whole for capacitors for three main reasons:

- The distribution capacitors might help in maintaining the power factor at the Transformer Station, hence further deferring the need for TS Capacitors. The distribution capacitors are much cheaper than the TS capacitors.
- Distribution capacitors will help maintain the voltage profile at the tail ends of especially the long feeders, hence improving the power quality to customers.
- There is potential for increased load demand in the east end of the City as this is the area of BPI's distribution territory with lands available for development. To accommodate this potential increase demand in this east end corridor, BPI must bring supply from the Powerline Transformer Station which is approximately 10 km away. The capacitor banks will provide additional capacity by maintaining the proper voltage on the feeders.

Name of Capital Project	Study Report on BPI Powerline Municipal Transformer Station 27.6 kV Capacitor & Reactive Support & Capacitor Banks Installation - 27.6 kV Distribution System
Capital Project #	9
USofA #	1835
Project Need & Purpose	**Study Report** - This specialized study is required to plan the installation of capacitor banks at the Powerline Municipal Transformer Station and the Distribution Feeders on a timely basis in order to avoid possible penalties from IESO and Hydro One if the Power Factor falls below 95% at the Transformer Station. The installation would also provide additional capacity on the Distribution System to meet new customer loads. The study will also make recommendations to maintain proper voltage at the Distribution Feeders' tail ends in order to maintain power quality as per Distribution System Code requirements. The study will recommend where capacitor banks are to be installed on BPI's distribution system. BPI is obligated by CSA to maintain a certain voltage range at a customer connection point.
Project Scope	**Study Report** • Examine the feasibility of adding static capacitor(s) at Powerline Municipal Transformer Station to address the need for expected reactive power compensation. Develop an implementation plan and initial schedule for future project. • Establish 27.6 kV voltage conditions at key points on the feeders in question for peak load and light load periods. • Examine the 27.6 kV voltage conditions for the off-normal load transfers (back-up transfers, extended feeder length, etc.) on the basis of one significant transfer per feeder.

	• Establish optimal locations and magnitude for reactive power compensation for proposed capacitor locations on the 27.6 kV systems. • Review feeder voltage profiles for peak and light load periods; establish the desirability and effectiveness of distributed capacitor switching. **Capacitor Banks Installation** • Recommendations from the capacitor study will create the scope of work.
Cost-benefit analysis, as applicable	The alternative to distributed capacitor banks is to build a 2nd Transformer Station (after Powerline Municipal Transformer Station) in the North-East end of the City of Brantford. The cost of such a project is prohibitive as compared to installing capacitor banks in the distribution system.
Starting dates and in-service dates	2013
Forecasted Costs	$120,000
Who performed the work [in-house vs. contracted]	Contracted and in-house.
Procurement method where work was contracted	Single source approved by BPI board

6. CONVERSION OF LINES FROM 4 AND 8 Kv TO 27 Kv SYSTEM

General Description:

This discretionary project involved upgrading existing line sections on the main distribution network, as well as some servicing feeds to industrial/commercial customers, from the older 8 kV/4 kV standard to the current 27.6 kV.

	Primary services and older 27.6kV Townhome sites
Capital Project #	10
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose:	These systems required upgrade due to age and/or lack of maintenance over the years. The monies set aside for these upgrades in 2011 and consequent

	years, were based on the general scope of works as determined through inspections of the sites. The project take offs are dependent upon agreements signed with each of the independent condominium management and its residents as well as Commercial/Industrial customers.
Project Scope	The project involved ownership transfer agreements with the residents of condominiums/townhomes and owners of commercial/industrial sites, and subsequent transfer of customer owned (mainly secondary and primary cables) to BPI to do the planned upgrades as well as replace existing transformers and support infrastructure.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2013
Forecasted Costs	$110,000
Who performed the work [in-house vs. contracted]	In-house/contracted
Procurement method where work was contracted	If by outside contractors, through general line contract through competitive bidding process

1 **7. ANNUAL POLE REPLACEMENTS & GENERAL REBUILDS – ASSET**
2 **MANAGEMENT SYSTEM**

3 A general description for Annual Pole Replacements and General Rebuilds is provided under
4 Exhibit 2, Tab 3, Schedule 2, and Page 10.

Name of Capital Project	General Yearly Rebuilds
Capital Project #	11
USofA #	1830, 1835, 1840, 1845, 1850
Project Need & Purpose	Annual rebuilds of existing lines and equipment projects include spot replacement of poles and upgrades of overhead feeders and secondary lines, underground conduit and vaults, overhead or underground conductors and devices and line transformers.
Project Scope	Amount of rebuilds are not based on specific scope requirements for the year, but based on

	historic spends.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2013
Forecasted Costs	$390,000
Who performed the work [in-house vs. contracted]	In-house and contracted.
Procurement method where work was contracted	Open competitive bidding based on yearly approved, pre-qualified contractors.

8. ASSET MANAGEMENT CONSULTANCY & SOFTWARE

General Description

BPI engaged UEM to develop a multi-year Asset Management Program in 2010. The first year objective was to deliver a capital plan in support of rate rebasing application and this was achieved by the end of 2011.

BPI in consultation with UEM developed a plan of action in 2012 and work was started to execute the same over a 5 year period. BPI is undertaking the second year of implementation in 2013 and requires the continued support from UEM as BPI's consultant and to purchase supporting software that can work in conjunction with our existing GIS platform to fulfill the asset management requirements. In 2013 BPI plans to convert to an electronic system for field asset condition data collection and this will be a significant undertaking.

Procurement method where work was contracted	N/A
Name of Capital Project	Asset Management Consultancy and Software
Capital Project #	12
USofA #	1835
Project Need & Purpose	In the course of the 2008 rate application, BPI committed to investigate Asset Management after identifying an internal need for a risk focused approach to asset management and to develop a sustainable long term program to better manage

	our assets and better inform the capital plan and budgets for timely asset replacement needs.
Project Scope	The scope covers all activities outlined in the 5-year asset management plan involving consultancy work and supervision by UEM, GIS related upgrades and new software installation by Intergraph (GIS vendor) and UEM as well as individual data collection, assimilation, storage and processing by BPI staff and City IT Services. This includes but is not limited to modifying parameters of gap analysis, model data collection.. The priority for 2013 is the implementation of technologies and business practices to collect asset condition data in electronic form in the field.
Cost-benefit analysis, as applicable	The alternate to having a consultant with expertise in the field and working with BPI staff and existing systems, was to purchase an expensive off-the-shelf software as well as paying to modify it and integrate with the existing systems and business processes. This would be far more costly, time consuming and resource intensive.
Starting dates and in-service dates	2013
Forecasted Costs	$150,000
Who performed the work [in-house vs. contracted]	The work will primarily be performed by BPI staff in consultation with UEM as well GIS related upgrades by the vendor (Intergraph). BPI will enter into single source agreements with UEM annually based on the performance of the previous years and work by Intergraph will be through the service level agreement with them to support the existing GIS platform
Procurement method where work was contracted	Sole source provider – UEM as approved by the Board of Directors; vendor for in the field data collection technologies to be selected through a competitive process.

9. METERING

A general description for Metering is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Metering (Meters & Instrument Transformers)
Capital Project #	13
USofA #	1860
Project Need & Purpose	These meters and where applicable, metering instrument transformers are required at connection locations that require Measurement Canada compliant metering for settlement purposes.
Project Scope	Metering installations at new customer locations and at locations where the meter and/or metering transformers have failed. Approximately 510 new locations/meters.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2013
Forecasted Costs	$205,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	N/A

10. REPLACEMENT OF VEHICLES

A general description for Replacement of Vehicles is provided under Exhibit 2, Tab 3, Schedule 2, Page 12.

Name of Capital Project	Replacement of Vehicles
Capital Project #	14
USofA #	1930
Project Need & Purpose	Vehicle replacements required due to excessive mileage and/or expiry of service life. • Large pick-up truck with crew cab (2000) due to mileage and wear with one the same or similar. • Small pick-up truck (2003) due to excessive mileage (282,000 km) with another the same or similar. • One-Ton Truck (2003) due to excessive mileage and wear with another the same or similar.

Project Scope	Procurement of vehicles is in compliance with BPI's purchasing policy. BPI considers age and condition of vehicles plus recommendations from a consultant and repair service providers and opinion of users when making fleet replacement decisions.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2013
Forecasted Costs	$200,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

11. CUSTOMER SERVICE REQUIREMENTS

General Description:

These are nondiscretionary projects that are required as BPI customer service works toward separating functions that were formerly shared with the City of Brantford.

Name of Capital Project	Customer Services (CS) Requirements
Capital Project #	15
USofA #	1925
Project Need & Purpose:	The costs include Bell Symposium call center software and an Interactive Voice Response (IVR) system.
Project Scope	Both are required to create a separate BPI Customer Service infrastructure.
Cost-benefit analysis, as applicable	N/A
Starting dates and in-service dates	2013
Forecasted Costs	$200,000
Who performed the work [in-house vs. contracted]	In-house
Procurement method where work was contracted	Tender

12. RECOVERIES/CAPITAL CONTRIBUTIONS

A general description for Recoveries/Capital Contributions is provided under Exhibit 2, Tab 3, Schedule 2, Page 13.

Description	**USofA**	**Budgeted Costs**
Grants and Capital Contributions	1995	($203,440)

CAPITALIZATION POLICY

The BPI Board of Directors approved the new “Accounting Policy - Capital Assets” on September 27, 2012. This replaced the former “Accounting Policy – Capitalization” that was approved by the BPI Board of Directors on September 21, 2006.

The “Accounting Policy -- Deferred Charges” that was in effect since September 21, 2006 provided guidance on how BPI would defer and amortize expenses incurred in a current year where the expected future benefit would accrue over a number of years was rescinded on September 27, 2012. The Deferred Charges policy was adopted to address the treatment of certain charges under the service level agreement where the service provider, the City of Brantford, purchased assets for use in providing services to BPI.

The “Accounting Policy - Capital Assets” approved by the BPI Board of Directors on September 27, 2012, provided for the recording of capital assets including property plant and equipment and intangible assets. Such capital assets comprise assets that are included in rate base for rate regulated purposes

The “Accounting Policy - Capital Assets” was developed to be consistent with:

- International Financial Reporting Standards as contained in Part 1 of the *Canadian Institute of Chartered Accountants (CICA) Handbook*; and
- The Ontario Energy Board’s *Accounting Procedures Handbook for Electricity Distributors.*

BPI has provided copies of the “Accounting Policy - Capital Assets, Accounting Policy – Capitalization” and “Accounting Policy – Deferred Charges” in Appendix A.

APPENDIX A

ACCOUNTING POLICY – CAPITALIZATION - 2006
ACCOUNTING POLICY – CAPITAL ASSETS - 2012
ACCOUNTING POLICY – DEFERRED CHARGES – 2006

BRANTFORD POWER INC.

Policy No.: 19

Policy: **ACCOUNTING POLICY- CAPITALIZATION**

Date Adopted: **September 21, 2006**

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1) Purpose

The following policy provides the Accounting Policy to be used by the Company for reporting Capital Assets.

2) Guidelines

The Company's Capitalization Policy will be consistent with the accounting pronouncements issued from time to time by Ontario Energy Board including the requirements of the "Accounting Procedures Handbook for Electric Distribution Utilities".

3) Types of Capital Assets

The Company may have one of two types of capital assets, which require capitalization on the Company's Balance Sheet as outlined below:

a) **Grouped Capital Assets:** are those assets that by their nature make identification of individual components impractical. Examples include distribution lines, transformers, meters, etc.

b) **Identifiable Capital Assets:** are those assets which have a material unit cost for financial reporting purposes and is tracked on an individual unit basis. Examples include fleet purchases, major tools etc.

4) Capital Expenditures - General

An expenditure is considered a capital expenditure when the Company purchases and acquires legal title to Grouped Assets or Identifiable Assets that:

a) Are held for use in the production or supply of goods and services, for administrative purposes or for the development, construction, maintenance or repair of other capital assets;

b) Have been acquired constructed or developed with the intention of being used on a continuing basis;

c) Are not intended for sale in the ordinary course of business; and

d) Will provide the Company with benefits lasting beyond 1 full year.

5) Capital Expenditures – Rebuilding, Refurbishments or Betterments

All costs for capital asset rebuilding, refurbishments or betterments, which may be undertaken as part of maintenance activities should be recorded as a capital expenditure if the change improves the service potential of a capital asset. Service potential is considered to be enhanced in the following circumstances:

a) When there is an increase in the previously assessed physical output or service capacity;

b) When the associated operating costs are lowered;

c) When the life or useful life is extended, or;

d) When the quality of the output is improved.

All maintenance costs incurred to maintain the existing service potential must be recorded as a repair or maintenance costs.

6) Capital Expenditures – Materiality Guidelines

Any items deemed capital pursuant to this Policy, will be classified as capital expenditures as long as their related costs meet or exceed the following minimum dollar value thresholds:

a) For grouped assets where the cumulative value of any distribution project or any annual refurbishment program constructed by or for the Company is at least $10,000;

b) For greater clarity with respect to distribution assets, the replacement of one or more poles, transformers, three phase switches and any related hardware would normally be capitalized as the cumulative impact of replacing such equipment throughout the distribution system would exceed the $10,000 criteria;

c) The replacement of insulators, cross arms, connectors, one phase switch and other small items would not normally be considered significant enough to the distribution system to warrant capital treatment. As a result, these items would normally be expensed to a maintenance work order unless such costs are part of a specific annual refurbishment program where the annual costs would exceed the $10,000 criteria;

d) For other grouped assets, the cumulative value of annual purchases exceed $1,000;

e) For identifiable assets, the asset is at least $1,000;

f) All items that fall below the thresholds in items 6(a), (b), (c), (d) and (e) shall be expensed in the year of purchase to a appropriate operations or maintenance work orders consistent with the nature of the work performed or to administrative expense accounts as applicable.

7) Capital Expenditures – Other Considerations

The following additional considerations are provided to ensure the correct accounting of capital expenditures:

a) Specific expenses for goods or services that are directly related to a capital project even though the particular good or service would not be considered capital had it been purchased as an unrelated purchase, are to be capitalized as part of the said capital project;

b) The capital costs of any constructed assets will include appropriate amounts of direct and indirect overhead costs consistent with the overhead cost allocation framework established by the Company and updated annually during the Company's budget process;

c) The capital costs of any constructed assets will include an appropriate allowance for use of funds during construction in accordance with the guidelines of the Accounting Procedures Handbook for Electric Distribution Utilities;

d) The gross value of distribution plant constructed by others but assumed by the Company will be recorded in the applicable capital asset accounts and in the offsetting contra account for contributed capital based on the costing information contained In the developers' engineering certificates;

e) Where circumstances arise that in the opinion of the CFO-Utilities, in consultation with the Company's external auditors, the application of the above guidelines would not accurately reflect the substance of the purchase in the Company's accounts, the transaction should be recorded in a fashion that fairly presents the nature of the transaction.

BRANTFORD POWER INC.

Policy No.: **22**

Policy: **ACCOUNTING POLICY- CAPITAL ASSETS**

Date Adopted: **September 27, 2012**

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1) Purpose

The following represents the Accounting Policy to be used by the Company for recording capital assets including property plant and equipment and intangible assets. Such capital assets will comprise assets that are included in rate base for rate regulation purposes as well as assets that are related to any non-rate regulated activities of the Company.

2) Guidelines

The Company's Capital assets Policy has been developed to be consistent with:

- International Financial Reporting Standards as contained in Part I of the Canadian Institute of Chartered Accountants (CICA) Handbook;
- The Ontario Energy Board's (OEB) Accounting Procedures Handbook for Electricity Distributors.

As accounting instructions are issued by the OEB for rate making and regulatory monitoring purposes and accounting standards are approved by the Canadian Accounting Standards Board (AcSB) for use in general purpose external financial reporting, there may be circumstances where differences will exist in proposed accounting treatment for the same transactions. In those circumstances, BPI's accounting policy for capital assets will comply with the requirements specified by both bodies when preparing financial reporting for their respective purposes.

BPI will generally harmonize its accounting treatment for capital assets in keeping with the OEB's requirements unless such treatment is specifically prohibited or the regulatory treatment is not in keeping with generally accepted practice in the preparation of general purpose financial reporting.

3) Types of Capital assets

The Company's capital expenditures will typically include additions to the following types of capital assets:

a) **Like or grouped capital assets:** Like or grouped capital assets are those individually insignificant items that by their nature may make identification of individual items impractical for accounting purposes. As such, recognition criteria are applied to the aggregate value rather than to individual items. Examples include poles, conductor, low voltage transformers and low value meters etc.

b) Readily identifiable asset or component: A readily identifiable asset or component is an asset or a component of a major asset that has a significant unit cost for financial reporting purposes and is tracked on an individual unit basis (i.e., not a like or grouped capital asset as discussed above). Accordingly, any capital asset or component that is readily identifiable in the records should be separately accounted for and depreciated over its estimated useful life. The asset or component must remain on the books as long as the asset or component exists and is capable of providing future benefit.

c) Major Spare Parts and Stand-by Equipment: Spare parts and servicing equipment are usually carried as inventory and recognized in profit or loss as consumed. However, major spare parts and stand-by equipment qualify as property, plant and equipment when the Company expects to use them during more than one period. Similarly, if the spare parts and servicing equipment can be used only in connection with a specific item of property, plant and equipment, they are accounted for as property, plant and equipment.

In most cases major spare parts and stand-by equipment (e.g. transformers and meters) should be accounted for as property, plant and equipment even if the items are physically stored in inventory. This is the case as it is expected that:

- **i)** these items are not held for sale in the ordinary course of business or will not be consumed in the rendering of distribution or other Company services;
- **ii)** the cost of the item can be measured reliably;
- **iii)** the item has a longer period of future economic benefit as compared to typical inventory items;
- **iv)** they form an integral part of the original distribution plant by enhancing the system reliability.

d) Intangible assets: Is other identifiable non-monetary asset without physical substance. For the Company, this would typically include software, land rights, and certain capital contributions paid by the distributor.

4) Capital Expenditures - General

An expenditure can be recognized as an asset when the Company purchases and acquires legal title to any item included in the four types of capital assets listed above provided that:

a) They embody a future economic benefit i.e., they have the potential to contribute directly or indirectly, to the flow of cash or cash equivalents to the Company;

b) The Company controls access to the benefit;

c) The transaction or event giving right to the Company's right to, or control of, the benefit has already occurred;

d) They are held for use in the supply of electricity distribution or other Company services, for administrative purposes or for the development, construction, maintenance or repair of other capital assets;

e) They have been acquired constructed or developed with the intention of being used on a continuing basis for more than one fiscal period;

f) They are not intended for sale in the ordinary course of business;

g) It is probable that the future economic benefits associated with the item will flow to the Company;

h) The cost of the item can be measured reliably.

5) Capital Expenditures – Property plant and equipment Measurement and Recognition

Property, plant and equipment should be measured at its cost, which includes

a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates. In the case of assets contributed in kind by developers or other customers pursuant to the Company's conditions of service, the gross value of assets contributed as outlined in the final engineer's project certificate;

b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The following are examples of directly attributable costs. These examples are illustrative and are not intended to be reflect all directly attributable costs:

   i) costs of employee labor and benefits arising directly from the construction or acquisition of the item of property, plant and equipment;

   ii) costs of site preparation;

   iii) initial delivery and handling costs;

   iv) installation and assembly costs;

   v) costs of testing whether the asset is functioning properly;

   vi) professional fees.

   Costs that are not considered directly attributable and would not be added to the cost of property plant and equipment include the following:

   i) costs of opening a new facility;

   ii) costs of introducing a new product or service (including costs of advertising and promotional activities);

   iii) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and

   iv) administration and other general overhead costs.

c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

Recognition of costs ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management. Therefore, costs incurred in using or redeploying an item is not included in the carrying amount of that item.

6) Capital Expenditures – Intangible Assets Measurement and Recognition

Intangible assets (software, land rights, certain capital contributions to distributors and transmitters) acquired by the Company will be measured initially at cost. Where an intangible asset is acquired through separate acquisition, the cost is comprised of the following:

a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates; and
b) any directly attributable cost of preparing the asset for its intended use. Directly attributable costs are similar to such costs outlined for property plant and equipment.

Similar to property, plant and equipment, recognition of costs in the carrying amount of an intangible asset ceases when the asset is in the condition necessary for it to be capable of operating in the manner intended by management.

7) Capital Expenditures – Subsequent Costs - Rebuilding and Refurbishments

All costs for property plant and equipment rebuilding or refurbishments which may be initiated as part of an asset management plan or preventative maintenance program may be added to the cost of property plant and equipment if, and only if:

a) It is probable that future economic benefits associated with the item will flow to the Company;
b) The cost of the item can be measured reliably.

Although the final decision regarding recognition of such costs into property plant and equipment will depend on the specific circumstances of the situation, an assessment of any impacts on service potential would typically be indicative of probable future economic benefits. Such considerations could include the following:

a) When there is an increase in the previously assessed physical output or service capacity;
b) When the associated operating costs are lowered;
c) When the life or useful life is extended, or;
d) When the quality of the output is improved.

In any situation where there is no change to the existing service potential, all costs must be reflected as a repair or maintenance costs.

The nature of intangible assets is such that, in many cases, there are no additions to such an asset or replacements of part of it. Accordingly, most subsequent expenditures are likely to maintain the expected future economic benefits embodied in an existing intangible asset. Therefore, only rarely will subsequent expenditure incurred after the initial recognition of an acquired intangible asset or after completion of an internally generated intangible asset will be recognized in the carrying amount of an asset. More typical will be the derecognition of the existing intangible asset offset by a new addition meeting the recognition criteria e.g. major upgrade of software.

7) Capital Expenditures – Derecognition, Disposal and Retirement

The carrying amount of an item of property, plant and equipment shall be derecognized:

a) On disposal:

b) When no future economic benefits are expected from its use or disposal.

Any resulting gain or loss on derecognition, disposal and retirement will be recognized an income or expense in the Statement of Operations.

8) Capital Expenditures - Contributions in Aid of Construction: In some cases, the Company may incur expenditures for amounts paid to other distributors or transmitters for capital projects i.e. for transmission upgrades or expansion projects. The costs incurred in these circumstances where no physical assets are acquired will be recorded as an intangible asset at the settlement value.

9) Capital Expenditures – Capitalization of Borrowing Costs: Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset including applicable intangible assets are included in the cost of that asset. A qualifying asset is defined as an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. For Brantford Power Inc. the substantial period of time is deemed to be activities exceeding 12 months duration.

The Company will begin capitalizing borrowing costs as part of the cost of a qualifying asset on the commencement date. The commencement date for capitalization is the date when the Company first meets all of the following conditions:

a) it incurs expenditures for the asset;

b) it incurs borrowing costs; and

c) it undertakes activities that are necessary to prepare the asset for its intended use or sale.

The Company will suspend capitalization of borrowing costs during extended periods in which it suspends active development of the qualifying asset and cease capitalizing borrowing costs when substantially all the activities necessary to prepare the qualifying asset for its intended use or sale are complete.

9) Capital Expenditures – Materiality Guidelines

Any item deemed a capital asset pursuant to this Policy, will be classified as a capital expenditure as long as their related costs meet or exceed the following minimum dollar value thresholds:

a) For like or grouped capital assets where the total annual cost of particular like or grouped capital assets purchased or constructed by or for the Company is at least $10,000 and meet the general capitalization criteria outlined above.

   For greater clarity with respect to distribution system related assets, the replacement of a single pole, transformer, switch and related hardware would normally be capitalized provided the addition met the above noted capitalization criteria even if the transaction costs were below $10,000 as the cumulative total value of such additions to like or grouped capital assets during a particular fiscal year would exceed the $10,000 criteria.

b) For identifiable assets, the asset is at least $1,000;

c) All items that fall below the thresholds in items 6(a) and (b) shall be expensed in the year of purchase to an appropriate operations or maintenance work orders consistent with the nature of the work performed or to applicable administrative expense accounts as applicable.

10) Capital Expenditures – Other Considerations

The following additional considerations are provided to ensure the correct accounting of capital expenditures:

a) Specific expenses for goods or services that are directly related to a capital project even though the particular good or service would not be considered capital had it been purchased as an unrelated purchase, are to be capitalized as part of the said capital project provided they are not administrative or general overhead in nature;

b) The gross value of distribution plant constructed by others but assumed by the Company will be recorded in the applicable capital asset accounts and in the offsetting contra account for contributed capital based on the costing information contained In the developers' Engineer's certificates;

c) Where circumstances arise that in the opinion of the CFO, in consultation with the Company's external auditors, the application of the above guidelines would not accurately reflect the substance of the purchase in the Company's accounts, the transaction should be recorded in a fashion that fairly presents the nature of the transaction in keeping with relevant accounting standards.

11) Depreciation and Amortization

There are a number of factors that the Company 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:

a) For general purpose financial statement reporting, the Company 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 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; the Company will consider proceeding with such a change.

b) 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 the Company 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.

c) 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.

d) 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. The Company will use this approach in depreciating or amortizing like or grouped capital assets.

e) 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, the Company includes in the cost of a self-constructed asset, amounts related to depreciation of vehicles used in the construction of that asset.

f) 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.

g) The future economic benefits embodied in an asset are consumed by the Company 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:

   i) Expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output;

   ii) 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;

   iii) 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;

   iv) 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 the Company. The asset management policy of the Company 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 the Company with similar assets in similar installations.

BRANTFORD POWER INC.

Policy No.: **20**

Policy: **ACCOUNTING POLICY- DEFFERED CHARGES**

Date Adopted: **September 21, 2006**

Repealed: September 27, 2012

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1) Purpose

The following policy provides the Accounting Policy to be used by the Company for Current and Non Current Deferred Charges.

2) Guidelines

The Company's Deferred Charges Policy will be consistent with the accounting pronouncements issued from time to time by Ontario Energy Board including the requirements of the "Accounting Procedures Handbook for Electric Distribution Utilities".

3) Types of Deferred Charges

The Company may have one of two types of deferred charges, which require capitalization on the Company's Balance Sheet as outlined below:

a) **Service Level Agreement Deferred Charges:** represent the proportion of service fees incurred pursuant to the Service Level Agreement with the City of Brantford which can be reasonably expected to be of benefit to Brantford Power Inc. beyond the current fiscal year.

b) **General Deferred/Prepaid Charges:** represent the proportion of any fees, service contracts or other payments not related to the Service Level Agreement which can be reasonably expected to be of benefit to Brantford Power Inc. beyond the current fiscal year.

4) Deferred Charges – Service Level Agreement Fees and Other General Deferred/Prepaid Charges

In situations where a proportion of service fees incurred pursuant to the Service Level Agreement with the City of Brantford or where other third party fees and charges can be reasonably expected to be of benefit to Brantford Power Inc. beyond the current fiscal year, the following accounting procedures shall be followed:

a) The total costs shall be recorded as a Service Level Agreement Deferred Charge or General Deferred/Prepaid Charges as applicable, and amortized on a straight-line basis over the expected period of benefit. These cost would typically be of the following nature:

i) **Service Level Agreement Deferred Charges**: Service Level Agreement fees related to facility improvements or for increases in the service provider's equipment dedicated to the Company such as furniture and fixtures, office and computer equipment etc.;

ii) **General Deferred/Prepaid Charges**: Non Service Level Agreement fees and charges related to licences, service contracts or other recurring charges for which renewal dates do not coincide with the Company's December 31 year end or for terms that go beyond one year in duration.

b) The annual amortization shall be charged to the applicable operating expenses where the regular Service Level Agreement charges or where General Deferred/ Prepaid Charges are recorded and should be considered as the expensing of the applicable charges and not be considered depreciation or amortization of capital assets;

c) Any portion of the deferred charges related to the benefit the Company will realize in the next fiscal year shall be reported as a current asset as a current Service Level Agreement deferred charge or as a current general deferred/prepaid charge as applicable with the remainder being reported as a Long Term Service Level Agreement or General Deferred Charge;

d) Although all deferred charges will be reported in a summarized fashion on the financial statements as current or long term deferred charges, separate classes of deferred charges must be maintained to ensure that each series of deferred charges are identified with the following particulars:

i) A description of the nature of the charge including whether the deferred charge is related to the Service Level Agreement or whether it is a General Deferred Charge;

ii) The year incurred;

iii) The department or organizational unit responsible, and;

iv) The period of expected benefit.

e) The period of expected benefit should be determined considering all of the relevant factors including the following guidelines:

i) **Service Level Agreement Deferred Charges**: Where the period of benefit has some relationship to one or more identifiable capital assets acquired by the City of Brantford for the purpose of providing such services, the period of benefit should be consistent with the depreciation rates for such capital assets prescribed by the Ontario Energy Board in its Electricity Distribution Rate Handbook.

ii) General Deferred/Prepaid Charges: In other cases, the period of benefit will typically be related to the shorter of the initial term of any related agreements or the period over which particular goods or services are to be provided.

5) Service Level Agreement and General Deferred/Prepaid Charges – Materiality

The recording of any expenditure as a Deferred Service Level Agreement or General Deferred/Prepaid Charges shall only be considered when the annual amortization amount is at least $1,000.

6) Service Level Agreement and General Deferred/Prepaid Charges – Other Considerations

The following additional guidelines should be considered when administering any Service level Agreement or General Deferred/Prepaid charges to ensure the asset values continue to be appropriate:

a) At least once a year, the particulars of each class of Service Level Agreement or General/Prepaid deferred charges are to be reviewed to confirm the remaining period of benefit. In situations where the period of benefit is projected to be less than originally anticipated, the remaining unamortized deferred charges should be amortized on the basis of the revised period of benefit. If no further period of benefit is expected or there is some risk in the Company being able to achieve the expected benefits, the full-unamortized value should be written off in the period in which such determination is made.

b) Where circumstances arise that in the opinion of the CFO-Utilities, in consultation with the Company's external auditors, the application of the above guidelines related to Service Level Agreement and General Deferred/Prepaid Charges, would not accurately reflect the substance of the transaction in the Company's accounts, the transaction should be recorded in a fashion that fairly presents the nature of the transaction.

CHANGES TO CAPITALIZATION POLICY

The changes to BPI's capitalization policy as approved in September 2012 as compared with its previous policy are set out below. Of particular note, Section 12 of the current capitalization 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 is a significant change from BPI's prior capitalization policy and practices.

- **Section 3 – Types of Capital Assets:**

Enhanced to add more detailed criteria:

- Refers to <u>like</u> as well as grouped capital assets
- Defines readily identifiable assets or asset components
- Adds treatment of major spare parts and standby equipment
- Adds treatment of intangible assets

- **Section 4 – Capital Expenditures – General:**

Enhanced to add more detailed and sets out the criteria for expenditure recognition as an asset and adds new criteria including:

- An expenditure embodies a future economic benefit
- BPI controls access to the benefit The transaction or event that gives BPI the right to or control of the benefit has already occurred (e.g. subdivision assets developed by developers where ownership is transferred to BPI)

- **Section 5 – Property Plant and Equipment Measurement and Recognition:**

This new section to the policy sets out the criteria for the measurement of cost of property plant and equipment

- **Section 6 – Intangible Assets Measurement and Measurement and Recognition:**

New section with the addition of intangible assets to the Type of Capital Assets to the policy
(e.g. as above, stranded meters)

- **Section 7 – Capital Expenditures – Capital Expenditures – Subsequent Costs – Rebuilding and Refurbishment:**

Clarifies that costs for property plant and equipment rebuilding or refurbishments which may be initiated as part of an asset management plan or preventive maintenance program are capitalized and includes the criteria that consideration of capitalization would be based on an assessment of any impacts on service potential indicative of probable future economic benefit

- **Section 8 – Capital Expenditures – Derecognition, Disposal and Retirement:**

This is a new section to the policy and sets out the criteria for derecognizing a capital asset

- **Section 9 – Contributions in Aid of Construction:**

This is a new section to the policy and sets out criteria for capitalizing capital contributions paid to other distributors or transmitters where no physical assets are acquired which are treated as intangible assets.

- **Section 10 – Capital Expenditures – Capitalization of Borrowing:**

Sets out the criteria for capitalizing borrowing costs directly attributable to the development of assets including intangible assets; for developmental activities exceeding 12 months duration.

- **Section 11 – Materiality Guidelines:**

No substantive changes

- **Section 12 – Capital Expenditures – Other Considerations:**

This section of the policy specifies expenses that are related to administrative and general overhead are not capitalized and removes the provisions to capitalize such direct and indirect overhead costs

New Componentization Structure/Change of Useful Lives

Under Modified CGAAP, each component of an item of Property Plant and Equipment (“PP&E”) and intangible assets with a cost that is significant in relation to the total cost of the item and for which different depreciation methods or rates are appropriate are to be depreciated separately.

Under CGAAP, BPI recorded PP&E as pooled assets based on major asset classes in the year of capitalization, and generally consisted of high level asset groupings such as overhead distribution, underground distribution, as well as distinct components such as rolling stock.

The transition to Modified CGAAP has impacted the calculation of BPI’s PP&E pooled assets. This change has also impacted the 2013 rate base and the 2013 distribution revenue requirement.

BPI’s new asset useful lives shown in Table 2.19 are within the ranges specified in the Asset Depreciation Study. There are five asset classes, which are exceptions as they do not fall within the ranges resulting from the Asset Depreciation Study. These exceptions are outlined after Table 2.19.

BPI applied its professional judgment to establish a new level of asset componentization under Modified CGAAP which is consistent with the requirements under IAS 16.9. BPI determined that some of the assets identified were individually insignificant and would not be recognized as separate assets or components under Modified CGAAP. BPI’s asset management program is set to replace immaterial and insignificant components at the same time as the significant component, if it is more prudent and efficient to do so at the time of replacement.

Table 2.19 – Summary of Useful Lives

				Useful Life Min	Useful Life Typical	Useful Life Max	BPI Decision	Within Range?	OEB Account	JDE Account
OVERHEAD LINES (OH)										
1	Fully Dressed Wood Poles	Overall		35	45	75	45	yes	1830	600.0460.183004
		Cross Arm	Wood	20	40	55	45	yes	1830	600.0460.183004
			Steel	30	70	95	45	yes	1830	600.0460.183004
2	Fully Dressed Concrete Poles	Overall		50	60	80	60	yes	1830	600.0460.183005
		Cross Arm	Wood	20	40	55	60	no	1830	600.0460.183005
			Steel	30	70	95	60	yes	1830	600.0460.183005
3	Fully Dressed Steel Poles	Overall		60	60	80	60	yes	1830	600.0460.183005
		Cross Arm	Wood	20	40	55	60	no	1830	600.0460.183005
			Steel	30	70	95	60	yes	1830	600.0460.183005
4	OH Line Switch			30	45	55	45	yes	1835	600.0460.183509
5	OH Line Switch Motor			15	25	25	25	yes	1835	600.0460.183505
6	OH Line Switch RTU			15	20	20	20	yes	1835	600.0460.183506
7	OH Integral Switches			35	45	60	45	yes	1835	600.0460.183507
8	OH Conductors			50	60	75	60	yes	1835	600.0460.183508
9	OH Transformers and Voltage Regulators			30	40	60	40	yes	1850	600.0460.185006
10	OH Shunt Capacitor Banks			25	30	40	N/A	N/A	N/A	N/A
11	Reclosers			25	40	55	40	yes	1835	600.0460.183504
TRANSFORMER AND MUNICIPAL STATIONS (TS & MS)										
12	Power Transfomers	Overall		30	45	60	45	yes	1815	600.0460.181505
		Bushing		10	20	30	45	no	1815	600.0460.181505
		Tap Changer		20	30	60	45	yes	1815	600.0460.181505
13	Station Service Transformers			30	45	55	45	yes	1815	600.0460.181506
14	Station Grounding Transformer			30	40	40	N/A	N/A	N/A	N/A
15	Station DC System	Overall		10	20	30	20	yes	1815	600.0460.181511
		Battery bank		10	15	15	20	no	1815	600.0460.181511
		Charger		20	20	30	20	yes	1815	600.0460.181511
16	Station Metal Clad Switchgear	Overall		30	40	60	40	yes	1815	600.0460.181504
		Removable Breaker		25	40	60	40	yes	1815	600.0460.181504
17	Station Independent Breakers			35	45	65	N/A	N/A	N/A	N/A
18	Station Switch			30	50	60	50	yes	1815	600.0460.181503
19	Electromechanical Relays			25	35	50	N/A	N/A	N/A	N/A
20	Solid State Relays			10	30	45	N/A	N/A	N/A	N/A
21	Digital & Numeric Relays			15	20	20	20	yes	1815	600.0460.181508
22	Rigid Busbars			30	55	60	N/A	N/A	N/A	N/A
23	Steel Structure			35	50	90	N/A	N/A	N/A	N/A

			Useful Life			BPI	Within	OEB	JDE
			Min	Typical	Max	Decision	Range?	Account	Account
	UNDERGROUND SYSTEMS (UG)								
24	Primary Paper Insulated Lead Covered (PILC) Cable		60	65	75	35	no	1845	600.0460.184504
25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	35	no	1845	600.0460.184504
26	Primary Non-Tree Retardant Cross Linked Polyethylene Cables - Direct Buried		20	25	30	35	no	1845	600.0460.184504
27	Primary Non-Tree Retardant Cross Linked Polyethylene Cables - In Duct		20	25	30	35	no	1845	600.0460.184504
28	Primary Tree Retardant Cross Linked Polyethylene Cables - Direct Buried		25	30	35	35	yes	1845	600.0460.184504
29	Primary Tree Retardant Cross Linked Polyethylene Cables - In Duct		35	40	55	35	yes	1845	600.0460.184504
30	Secondary Paper Insulated Lead Covered Cables		70	75	80	35	no	1845	600.0460.184506
31	Secondary Cables - Direct Buried		25	35	40	35	yes	1845	600.0460.184506
32	Secondary Cables - In Duct		35	40	60	35	yes	1845	600.0460.184506
33	Network Transformers	Overall	20	35	50	N/A	N/A	N/A	N/A
		Protector	20	35	40	N/A	N/A	N/A	N/A
34	Pad-Mounted Transformers		25	40	45	40	yes	1850	600.0460.185004
35	Submersible and Vault Transformers		25	35	45	35	yes	1850	600.0460.185005
36	Underground Foundations		35	55	70	55	yes	1840	600.0460.184006
37	Underground Vaults	Overall	40	60	80	60	yes	1840	600.0460.184007
		Roof	20	30	45	30	yes	1840	600.0460.184008
38	Underground Vault Switches		20	35	50	35	yes	1845	600.0460.184508
39	Pad-Mounted Switchgear		20	30	45	30	yes	1845	600.0460.184509
40	Ducts		30	50	85	50	yes	1840	600.0460.184004
41	Concrete Encased Duct Banks		35	55	80	55	yes	1840	600.0460.184005
42	Cable Chambers		50	60	80	60	yes	1840	600.0460.184009

MONITORING AND CONTROL SYSTEMS

			Low	Average	High	BPI Decision	Within Range?	OEB Account	JDE Account
43	Remote SCADA		15	20	30	20	yes	1980	600.0460.198004

NON-DISTRIBUTION ASSETS

			Low	Average	High	BPI Decision	Within Range?	OEB Account	JDE Account
1	Office Equipment		5	10	15	10	yes	1915	600.0460.191501
2	Vehicles	Trucks/Bckts - Sm	5	10	15	10	yes	1930	600.0460.193004
		Trucks/Bckts - Lg	5	10	15	13	yes	1930	600.0460.193005
		Trailers	5	12.5	20	20	yes	1930	600.0460.193002
		Vans/Cars	5	7.5	10	8	yes	1930	600.0460.193003
3	Administrative Buildings		50	62.5	75	N/A	N/A	N/A	N/A
4	Leasehold Improvements		5	5	5	N/A	N/A	N/A	N/A
5	Station Buildings	Station Building	50	62.5	75	50	yes	1808	600.0460.180805
		Parking	25	27.5	30	25	yes	1808	600.0460.180806
		Fence	25	42.5	60	25	yes	1808	600.0460.180803
		Roof	20	25	30	20	yes	1808	600.0460.180804
6	Computer Equipment	Hardware	3	4	5	4	yes	1920	600.0460.192001
		Software	2	3.5	5	5	yes	1925	600.0460.192501
7	Equipment	Power Operated	5	7.5	10	N/A	N/A	N/A	N/A
		Stores	5	7.5	10	N/A	N/A	N/A	N/A
		Tools,Shop, Garage	5	7.5	10	10	yes	1940	600.0460.194001
		Measurement & Tes	5	7.5	10	N/A	N/A	N/A	N/A
8	Communication	Towers	60	65	70	N/A	N/A	N/A	N/A
		Wireless	2	6	10	5	yes	1955	600.0460.195501
9	Residential Energy Meters		25	30	35	N/A	N/A	N/A	N/A
10	Industrial/Commercial Energy Meters		25	30	35	25	yes	1860	600.0460.186008
11	Wholesale Energy Meters		15	22.5	30	15	yes	1860	600.0460.186009
12	Current & Potential Transformer (CT&PT)		35	42.5	50	35	yes	1860	600.0460.186010
13	Smart Meters		5	10	15	15	yes	1860	600.0460.186007
14	Repeaters - Smart Metering		10	12.5	15	10	yes	1860	600.0460.186005
15	Data Collectors - Smart Metering		15	17.5	20	15	yes	1860	600.0460.186006

NOT DETAILED ON KINECTRICS STUDY

			Low	Average	High	BPI Decision	Within Range?	OEB Account	JDE Account
42A	NEW - Underground Terminations		N/A	N/A	N/A	30	N/A	1840	600.0460.184009
	Land Rights		N/A	N/A	N/A	50	N/A	1806	600.0460.180601
	TS Equipment LT 50KV		N/A	N/A	N/A	30	N/A	1820	600.0460.182001
	Services		N/A	N/A	N/A	25	N/A	1855	600.0460.185504
	Major Pole Inspections		N/A	N/A	N/A	36	N/A	1830	600.0460.183006
	Contributions - these are componentized to the same level as the assets are - useful lifes for the contributions are the same as the components above		N/A	N/A	N/A	various	N/A	1995	600.0460.1995xx

BPI's review of asset useful lives as compared with the Asset Depreciation Study (Kinectrics Inc.) identified additional components or asset groups and some assets where, in BPI's opinion, typical useful lives should differ from those set out in the Asset Depreciation study. Those deviations from the typical useful lives set out in the Asset Depreciation Study are discussed below.

- **Fully Dressed Concrete and Steel Poles**

Since BPI does not have a significant number of steel poles, BPI has decided to combine concrete and steel poles into one asset class: Fully Dressed Concrete and Steel Poles.

Kinetrics Inc. Asset Depreciation Study results:

Asset Componentization		Useful Life (Years)		
		Minimum	Typical	Maximum
Overall		35	45	75
Cross Arm	Wood	20	40	55
	Steel	30	70	95

BPI's decision is to give Fully Dressed Concrete and Steel Poles a useful life of 60 years, including the cross arm. As the cross arms are typically changed when the poles are changed, it has been decided that it is not cost effective to track costs for poles separate from costs for cross arms. Also, cross arms currently being installed are strictly steel, which has comparable useful life to the poles.

- **Power Transformers**

Kinectrics Inc. Asset Depreciation Study results:

Asset Componentization	Useful Life (Years)		
	Minimum	Typical	Maximum
Overall	30	45	60
Bushing	10	20	30
Tap Changer	20	30	60

BPI's decision is to use 45 years for the useful life for all components of Power Transformers. Only the bushing component does not fall within the range suggested in the Asset Depreciation Study. Per review of all invoices that were incurred during construction, the bushings were a small part of the total. As a result, it was decided to group them together into one component.

- **Station Direct Current System**

Kinectrics Inc. Asset Depreciation Study results:

Asset Componentization	Useful Life (Years)		
	Minimum	Typical	Maximum
Overall	10	20	30
Battery bank	10	15	15
Charger	20	20	30

BPI has decided to assign Station Direct Current System and all of its components a useful life of 20 years. Due to the small differences in typical useful life, it was decided to leave these as one component.

- **Primary Paper Insulated Lead Covered (PILC) Cables**

Kinectrics Inc. Asset Depreciation Study results:

Asset Componentization	Useful Life (Years)		
	Minimum	Typical	Maximum
	60	65	75

BPI's decision is to assign PILC Cables a useful life of 35 years. It is not easily determined how the existing distribution system is allocated between the 6 primary cable components. Also, as the same inventory items can be installed in a direct buried or a duct underground installation, it will not be easy to track costs between the various components. Currently the majority of primary cables being installed are tree retardant. Per discussion with BPI's Operations group, cable is directly buried slightly more frequently than in duct. Capital projects could potentially have some of the cable directly buried and others in duct.

As a result, BPI management has decided to use one component for primary cable. This component will track all primary cables whether in duct or direct buried. The useful life of this component will be 35 years which is the maximum useful life for direct buried and the minimum useful life for in duct.

- **Secondary Paper Insulated Lead Covered Cables**

Kinectrics Inc. Asset Depreciation Study results:

Asset Componentization	Useful Life (Years)		
	Minimum	Typical	Maximum
	70	75	80

BPI's decision is to assign PILC Cables a useful life of 35 years. It is not easily determined how the existing distribution system is allocated between the 3 secondary cable components. Also, as the same inventory items can be installed in a direct buried or a duct underground installation, it will not be easy to track costs between the various components. Per discussion with BPI's Operations group, cable is directly buried slightly more than in duct. Capital projects could potentially have some of the cable directly buried and others in duct.

As a result, BPI management has decided to use one component for secondary cable. This component will track all secondary cables whether in duct or direct buried. The useful life of this component will be 40 years which is the maximum useful life for direct buried and the typical useful life for in duct.

Finally, a significant outcome of the Asset Depreciation Study is that LDCs will remain responsible for the review and update of their respective capital asset service lives for financial reporting and regulatory requirements. Therefore BPI will complete a review on an annual basis.

Capitalization of Overhead

Accompanying this section as Table 2.19 is a completed Board prescribed Chapter 2, Appendix 2-D regarding BPI's overhead costs on self-constructed assets. BPI also identifies its burden rates related to the capitalization of costs of self-constructed assets.

Table 2.19 Overhead Costs (Appendix 2-D)

Nature of the Overhead Costs	Dollar Impact on OM&A Historic Year	Dollar Impact on OM&A Bridge Year	Dollar Impact on OM&A Test Year	Dollar Impact - OM&A Variance Test versus Bridge	Dollar Impact - OM&A Variance Test versus Historic
employee benefits				$ -	$ -
costs of site preparation				$ -	$ -
initial delivery and handling costs (STORES - 22% markup on inventory)	$ 255,114	$ 233,994		-$ 233,994	-$ 255,114
costs of testing whether the asset is functioning properly				$ -	$ -
professional fees				$ -	$ -
costs of opening a new facility				$ -	$ -
costs of introducing a new product or service (including costs of advertising and promotional				$ -	$ -
costs of conducting business in a new location or with a new class of customer (including costs				$ -	$ -
administration and other general overhead costs	$ 333,433	$ 210,540		-$ 210,540	-$ 333,433
percentage allocation of senior management salaries, benefits and related expenses	$ 573,586	$ 542,466		-$ 542,466	-$ 573,586
				$ -	$ -
				$ -	$ -
Insert description of additional item(s) and new rows if needed.				$ -	$ -
Total	$ 1,162,133	$ 987,000	$ -	-$ 987,000	-$ 1,162,133

- **Burden Rates**

  BPI has two burden rates that are applied to capital costs of self-constructed assets:

  - An inventory burden rate of 22% to recover the costs incurred in the procurement and handling of inventory. The burden rate is applied to when materials are relieved from inventory. This burden rate was used up to and including 2012 but is no longer applied in 2013.
  - A payroll burden rate of 40.5% comprises benefits and such non-allocable time as vacation and sick time. The burden rate is applied to the labour hours booked to capital. BPI has not revised this burden rates since its last cost-of-service rate application.

ASSET MANAGEMENT PROGRAM

BPI began its Asset Management Program in 2010 and engaged UEM to assist with the development and implementation of the program. Accompanying this section as Appendices B-1 and B-2 is the Asset Management Program 2012 Executive Summary and the Asset Management Program 2012.

APPENDIX B-1

UEM ASSET MANAGEMENT EXECUTIVE SUMMARY

UEM Project No.: 13-400
Date: April 2013

Prepared for:

Brantford Power Inc.

Contact and Location:
Mr. Paul Kwasnik,
CEO, General Manager
84 Market Street
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Brantford, ON N3T 5N8

Asset Management Program 2012
Executive Summary

BRANTFORD POWER INC.
ASSET MANAGEMENT PROGRAM - EXECUTIVE SUMMARY

TABLE OF CONTENTS

LIST OF ACRONYMS

AMP	Asset Management Plan
AMPr	Asset Management Program
BOD	Board of Directors
BPI	Brantford Power Inc.
CHI	Condition Health Index
CLOS	Customer Level of Service
CoF	Consequence of Failure
ERL	Estimated Remaining Life
ESL	Estimated Service Life
IMM	International Infrastructure Management
LoS	Level of Service
KPI	Key Performance Indicator
ODM	Optimized Decision Model
OEB	Ontario Energy Board
PAS	Publically Available Specification
PoF	Probability of Failure
TLOS	Technical Level of Service
UEM	Urban and Environmental Management

1.0 INTRODUCTION

Brantford Power Inc. began the development and implementation of an Asset Management Program in June 2010 to support a rate rebasing application and improve the overall management of capital assets. The implementation and improvement of the Asset Management Program is an ongoing project which Brantford Power Inc. is undertaking in consultation with Asset Management specialists from Urban & Environmental Management. The Asset Management Program is designed to support the following key objectives:

- Develop, implement and maintain an Asset Management Program that will enable Brantford Power Inc. to optimize its asset investments though a disciplined and achievable multi-year approach
- Consider the Asset Management Program within a broad scope that includes relationships with other related programs and systems including the work order management system, inventory management system, and asset componentization as required by International Financial Reporting Standards
- Use the Asset Management Program to provide input into to the capital budgeting program in support of a rate rebasing application
- Provide documentation of the Asset Management Program describing the development process, its elements and decision-making parameters
- Provide a methodology to prioritize Capital Projects
- Incorporate the assessed condition of assets into the asset renewal selection process and investment decisions

These objectives are consistent with the international standards and principles guided by the International Infrastructure Management (IMM) manual and the Publically Available Specification for Asset Management (PAS -55).

This executive summary forms part of an overall holistic approach that conforms to industry best practices in Asset Management. The overall approach includes a Risk Policy, Risk Policy Asset Register, Risk Program and an Asset Management plan. Contextually the diagram below illustrates the overall strategy:

1.1 Program Justification

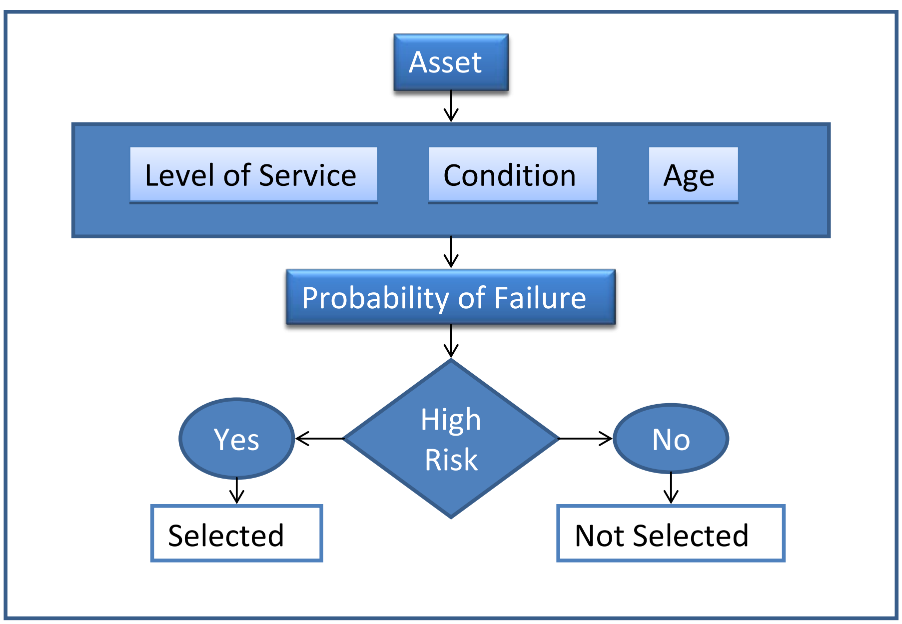
The management of infrastructure assets (e.g. their selection, maintenance, inspection and renewal) plays a key role in determining the operational performance and viability of organizations that operate assets as part of their core business. Asset Management is the process of making the right decisions and optimizing available resources. The common objective is to minimize the whole life cost of assets but there may be other critical factors such as risk or business continuity to be considered objectively in decision making. The benefits to Brantford Power of an Asset Management Program are significant and include:

- Improved distribution system performance and control of the Level of Service
- Improved financial planning for maintenance and replacement of key infrastructure assets, i.e. the ability to achieve and demonstrate best value-for money
- Improved risk management strategies
- Optimized return on investment and/or growth
- Improved health, safety and environmental performance
- Sustainable long-term planning and performance
- Improved corporate stewardship

Notwithstanding the above benefits, implementation of the Asset Management Program will also provide evidence to support future capital budget submissions to Board of Directors (BOD) and the Ontario Energy Board (OEB), in cost-of-service rate applications.

2.0 Selection and Prioritization Process

The above objectives result in the creation of a process that identifies capital projects based on asset management best practices. Urban & Environmental Management has developed an optimized decision methodology which is reflected in the selections criteria as illustrated in the following schematic. The optimized decision methodology takes into consideration costing, risk and service level of objectives.



Level of Service (LoS), Estimated Service Life (ESL) and condition inspections are used to determine the Probability of Failure of an asset. Six Risk Criteria are used to assess assets and determine Consequence of Failure levels as laid out in the Corporate Risk Policy (Considered and approved by the BOD). These criteria are:

- Health and Safety
- External Demands
- Operational
- Environmental
- Financial
- Political and Regulatory

Probability of Failure (PoF) and Consequence of Failure(CoF) are combined to determine an asset's Risk Level. The possible Risk Levels are:

- **Very High Risk:** Maximum risk mitigation measures should be in place, together with recovery plans, and availability of critical spares.
- **High Risk:** Maximum risk mitigation measures should be in place providing layers of deterrence, high probability of detection, and rapid effective response. Due diligence is required including utilization of appropriate expertise and validation of assessed data.
- **Moderate Risk:** Risk should be managed by the introduction of mitigation strategies and operational procedures.
- **Low Risk:** Minimal risk mitigation measures necessary. Risk should be managed through operational procedures, or accepted as a low business risk.

A process has been developed for capital project selection and prioritization. Capital projects are selected based on the geographical location and the assessed risk levels of assets. Geographic Information System software is used to map the location of all assets. All assets identified as "Very High Risk" are selected to be included in the projects. Project boundaries are determined manually based on geographical grouping of those assets identified as "Very High Risk" and those "High Risk" which are in close geographical proximity to the "Very High Risk" assets. Projects are prioritized based on the total risk scores of the assets within the project boundary and the number of outages that have been reported within the project area.

Both project selection and project prioritization results are based on the current available data. As data is updated the capital project selection and prioritization processes will improve accordingly.

2.1.1 SELECTED CAPITAL PROJECTS

Using the project selection method described above, projects were selected by the Urban & Environmental Management project team in consultation with Brantford Power Inc. staff. **Table 1** lists these projects in a prioritized order. **Figure 1** identifies the locations of selected projects. Table 1 and Figure 1 are included for illustrative purposes

2.1.2 PRIORITIZED PROJECTS

The projects selected under **Table 1** *Selected Projects* have been prioritized according to the total risk index and the total number of outages reported in the project area. Using the yearly capital budgets, projects can be selected from this list in order to maximize the amount of risk reduced in the system.

Table 1: Selected Projects

Order of Priority	Project #	Project Name	Total Assets	Reported Outages	Total Risk	Project Priority Score
1	9	Brant Avenue	118	63	18827	20.6
2	41	Colborne Street (Clarence to Stanley)	70	31	6979	9.4
3	1	Dalhousie Street (Clarence to Stanely)	78	26	10285	9.3
4	10	Farringford Drive & Pusey Boulevard	81	20	14100	9.1
5	24	Memorial Drive / Powerline Road	89	18	12968	8.3
6	23	North Park Street / Memorial Drive / Blackfriar Lane	41	24	7054	7.8
7	38	Downtown King Street / Queen Street	47	9	7677	4.5
8	39	Downtown Market Street	47	6	8931	4.2
9	37	Allensgate Drive / Myrtleville Drive	51	11	4535	4.0
10	19	Metcalf Crescent	22	10	4728	3.8
11	11	Forest Road / Keeler Place / Marvin Avenue	31	5	5422	2.9
12	4	Elgin Street Townhouses / Varga & Frank	4	9	589	2.3
13	36	Scarfe Gardens	8	7	1367	2.1
14	18	James Avenue / Grey Street	17	2	3147	1.5
15	5	Stanley Street Townhouses / Stanley Manor	9	3	2332	1.4
16	35	Dunsdon Street & Sheena Avenue	6	4	1158	1.3
17	17	Oak Hill Drive Townhouses	8	4	1124	1.3
18	8	Henry Street Townhouses 154-164	7	2	1802	1.0
19	21	Joysey Street / Ariel Street	5	2	938	0.8
20	3	Mohawk Street Townhouses	10	0	2368	0.7
21	6	Campbell Street Townhouses	5	1	935	0.5
22	7	Henry Street / Town & Country Townhouses	5	1	783	0.5
23	28	Colborne Street West / Oak Street	7	0	1267	0.4
24	31	Canada Court	6	0	1113	0.4
25	20	Holbor Street / Orchard Avenue	6	0	1054	0.3
26	27	Forbes Crescent	4	0	947	0.3
27	15	Darling Street / Twelfth Avenue	4	0	941	0.3
28	33	Alpha Crescent	5	0	927	0.3
29	40	Downtown Charlotte Street	6	0	891	0.3
30	25	Lynden Road / Roy Boulevard	3	0	782	0.2
31	32	Colborne St / Clara Crescent	2	0	460	0.1

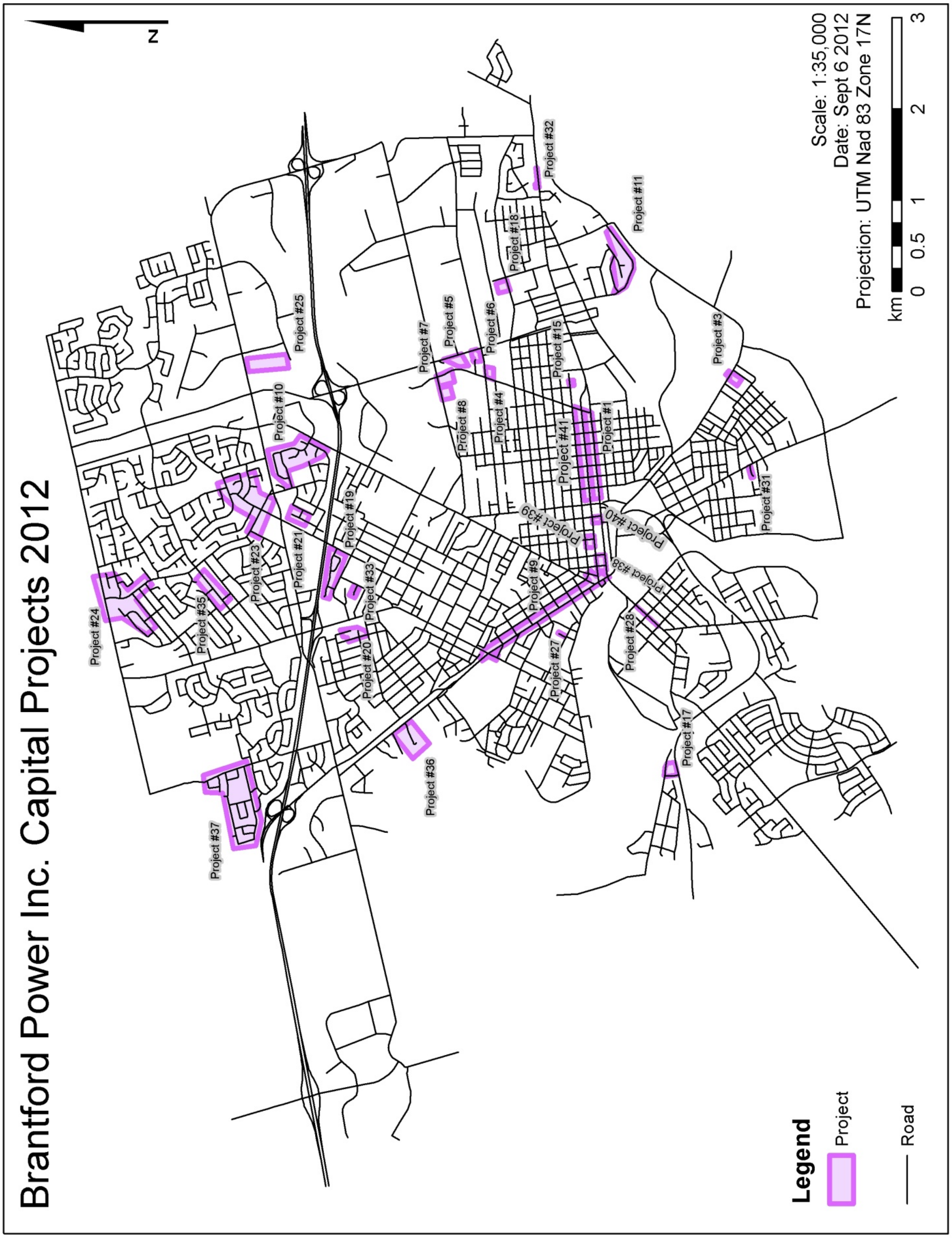


Figure 1: Map of Project Locations

2.1.3 Pole Replacement Projects

Brantford Power Inc. conducts the replacement of poles under a separate budgeting program from the other Capital Projects. Pole replacement projects are determined using a separate process from other asset classes. Geographical location is not taken into consideration to determine pole replacement projects. Poles are prioritized into a replacement order based on Risk Levels and those values used to determine Risk Levels in the following order:

1. Risk Level
2. Probability of Failure (PoF)
3. Consequence of Failure (CoF)
4. Estimated Service Lives (ESL)

Poles are selected from the prioritized lists to establish a replacement program subject to capital budget availability. A pole replacement program has been developed to cover a 5 year period as shown in Table 2 below:

Table 2: Pole Replacement Projects

Year	Criteria	Number	Total Risk
1	Very High Priority, PoF = 4 & Very High Priority, PoF = 3, ESL% >80%	36	8688
2	Remaining Very High Priority, PoF = 3	39	9090
3	High Priority, PoF = 4, ESL% > 127% or Unknown	31	3847
4	Some High Priority, PoF = 4, ESL% > 125%	37	4590
5	Remaining High Priority, PoF = 4, ESL% > 125%	39	4728
Total		167	28388

This pole replacement plan is to be reviewed annually and adjusted to account for updated condition inspection information.

3.0 Ongoing Improvement Program

3.1 Project Scope

At this time the scope of BPI's Asset Management Plan is limited to 6 asset classes: Poles, Structures, Switches, Transformers, Primary Cables and Conductors, and Secondary Cables and Conductors. As BPI's business and data management practices and procedures improve it is possible to increase this scope to include such assets as Conductor Nodes, Elbows, Fuses, vehicles and Information technology assets. The scope of the AMP is currently sufficient to develop Capital Projects, and associated budgets.

3.2 Data Gaps

BPI's current asset database contains gaps in the recorded data. Logical assumptions have been made to fill these gaps by UEM in consultation with the Engineering department. While the current data is sufficient, improved data collection and data maintenance procedures would further improve the Asset Management Program.

Currently BPI's Asset Database does not consistently maintain records relating to the date of installation for all assets. As BPI's Asset Database improves, as per the recommendations of this report, ESL values can be calculated for all assets which will improve the results of the ODM, the capital project selection process, and long term forecasting.

Ideally, the failure of specific assets could be tied directly to risk events that are used to capture the KPIs so that where applicable, predictions could be made when developing work projects as to what degree the KPIs would positively be affected per project. BPI's current data management procedures do not allow for this connection. An improved IT and data collection strategy will be able to link these factors and allow BPI to achieve a significant improvement in the output of the Asset Management Program.

3.3 Lifecycle Modeling

Currently, a linear relationship between Estimated Service Life (ESL) % and Probability of Failure (PoF) is used to model the lifecycle of assets (Figure 1).

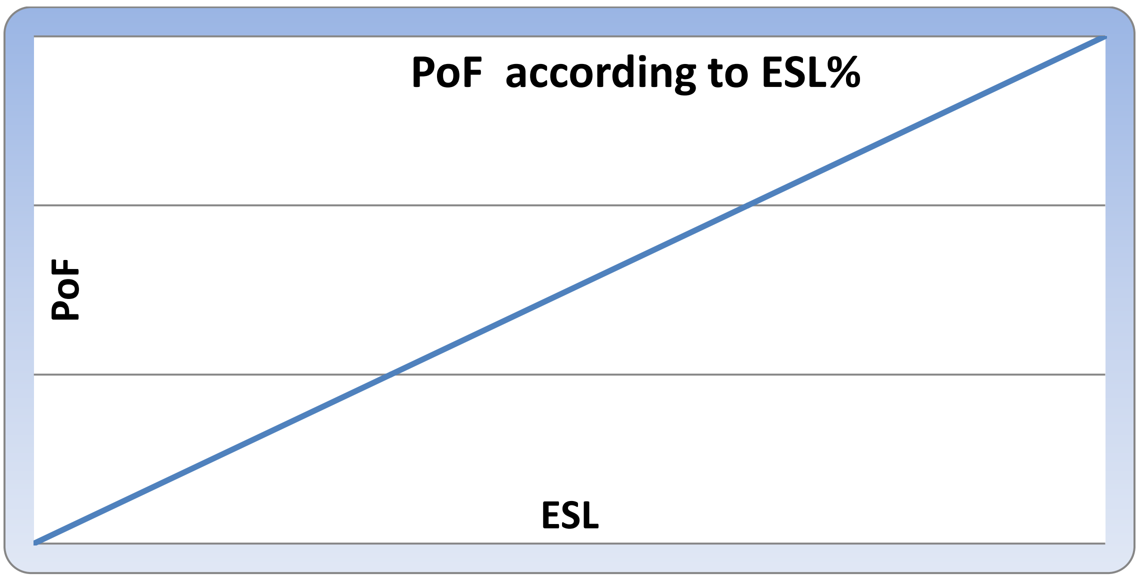


Figure 1: PoF According to ESL%

While straight line depreciation is adequate to predict the probable failure point of an asset, the development of lifecycles curves (Figure 2) for all asset classes and subtypes would improve the accuracy of the ODM providing a much more accurate Technical Level of Service with which to relate PoF to the age of the asset.

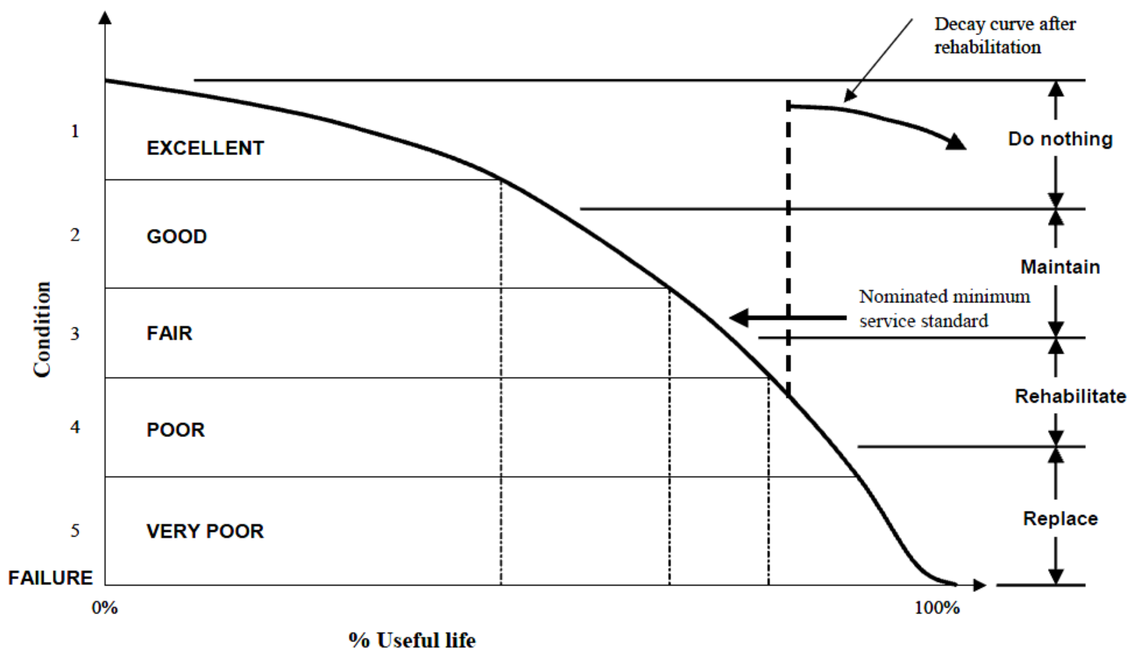


Figure 2: Example of Lifecycle Curve

This improved accuracy would allow the identification of more accurate Technical Level of Service for each asset class, providing the optimal timing for rehabilitation or replacement.

3.4 Critical Factor Scoring

BPI has developed and weighed critical factors for all asset classes. At this time the necessary connections between the critical scores and available data have not been made for all asset classes. Transformers and poles both have the required associated data with which to determine asset level scores for their critical factors. Transformers, which are able to be linked through both electrical connectivity and geographical location to all other asset classes, are leveraged to apply Consequence of Failure (CoF) values to all assets missing these values. While the logical application of the CoF scores in this way is sound, accuracy will be improved once the connection between data and critical scores for all asset classes is fully established.

3.5 Condition Assessment & Inspection Program

BPI with assistance from external resources is developing a GIS enabled mobile solution for condition assessments to be used during the three year condition assessment and inspection cycle. The implementation of the mobile solution will further ensure data integrity and allow direct input by inspectors into the asset database.

3.6 Business Processes

BPI's current asset management business processes have been reviewed by UEM. The current asset management processes contain some limited or missing data and processes. BPI is engaged in ongoing projects in order to fill the gaps in the current business process.

4.0 OBSERVATIONS

Substantial improvement of Asset Management practices has occurred at BPI since the inception of the Asset Management Program. Over time as the data quality improves, the quality and value of the asset Management processes will improve.

The current knowledge base concerning the lifecycle of the assets owned by most Local Distribution Companies is lacking when compared to the knowledge base found in many municipal utilities. This lack of knowledge will improve over time, and BPI's investment during this project will be a great contribution to the industry as a whole.

5.0 CONCLUSION

BPI has implemented an Asset Management Program which assesses infrastructure assets based on condition assessments, lifecycles, Level of Service requirements, and Risk Analysis. The Asset Management Program is expected to achieve an improved performance of the distribution system and reduce the number of outages caused by asset failure. The Asset Management Program uses a methodology which provides:

- A structured Capital Project Prioritization Methodology which is directly related to asset condition assessments and the Corporate Risk Policy.
- A formalized risk model based on the Corporate Risk policy which includes a focus on health and safety, operational, environmental, external demand, financial, and political and regulatory risk resulting in the program achieving direct benefits to the corporations overall goal of improving customer service.
- A proactive approach to asset management which uses Probability of Failure to identify potential asset failures, allowing appropriate actions to be taken to mitigate risk before it occurs.
- A risk centric approach to asset management which uses Consequence of Failure to identify the assets which pose the greatest risk to the organization, the customers, and the community so that mitigation activities can be applied in a prioritized manner.

The heart of BPI's Asset Management Program is UEM's Optimized Decision Model. The ODM applies the Asset Management strategies to BPI's asset data. The outputs of the ODM are used to develop and prioritize Capital Projects which address those assets that pose the greatest risk and identify assets that require risk mitigation measures to be in place.

The Asset Management Program is being improved yearly through improved data collection, data confidence, data architecture, business processes, and Asset Management procedures. Brantford Power is committed to a comprehensive Asset Management Program that can be used to provide appropriate information to the Board of Directors for capital planning decision making during the annual budget process.

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APPENDIX B-2

UEM ASSET MANAGEMENT REPORT

UEM PROJECT NO.: 13-400
DATE: APRIL 2013

PREPARED FOR:

BRANTFORD POWER INC.

CONTACT AND LOCATION:
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ASSET MANAGEMENT PROGRAM 2012

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LIST OF ACRONYMS

AM	Asset Management
AMP	Asset Management Plan
AMPr	Asset Management Program
BOD	Board of Directors
BPI	Brantford Power Inc.
CAIFI	Customer Average Interruption Duration Index
CHI	Condition Health Index
CLOS	Customer Level of Service
CoF	Consequence of Failure
DSC	Distribution System Code
ERL	Estimated Remaining Life
ESL	Estimated Service Life
GIS	Geographic Information System
IMM	International Infrastructure Management
KPI	Key Performance Indicator
LDC	Local Distribution Company
LoS	Level of Service
ODM	Optimized Decision Model
OEB	Ontario Energy Board
PAS	Publically Available Specification
PoF	Probability of Failure
S2A	Service to Asset
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TLOS	Technical Level of Service
UEM	Urban and Environmental Management

1.0 INTRODUCTION

Brantford Power Inc. began the development and implementation of an Asset Management Program in June 2010. The implementation and improvement of the Asset Management Program is an ongoing project which Brantford Power Inc. is undertaking in consultation with Asset Management specialists from Urban & Environmental Management. The Asset Management Program is designed to support the following key objectives:

- Develop, implement and maintain an Asset Management Program that will enable Brantford Power Inc. to optimize its asset investments though a disciplined and achievable multi-year approach.
- Consider the Asset Management Program within a broad scope that includes relationships with other related programs and systems including the work order management system, inventory management system, and asset componentization as required by International Financial Reporting Standards.
- Use the Asset Management Program to provide evidence to the capital budgeting program in support of a rate rebasing application.
- Provide documentation on the Asset Management Program describing the development process, its elements and decision-making parameters.
- Provide a methodology to prioritize Capital Projects
- Incorporate the assessed condition of assets into the asset renewal selection process and investment decisions

These objectives are consistent with the international standards and principles guided by the IIM manual and PASS -55. The benefit to Brantford Power of an Asset Management Program is significant and includes:

- Improved performance and control of the Level of Service (LOS)
- Improved financial planning for maintenance and replacement of key infrastructure Assets
- Improved Risk Management Strategies
- Optimized return on investment and/or growth
- Improved health, safety and environmental performance
- Sustainable long-term planning and performance
- Improved corporate stewardship

2.0 BACKGROUND

To provide appropriate information to the Board of Directors for capital planning decision making during the annual budget process, Brantford Power has recognized the importance of comprehensive Asset Management planning. The long term goal is to develop an Asset Management Program that can be used to:

- Review the condition of assets (poles, wires, cables, transformers, switches, structures)
- Prioritize the action to be taken to maintain/replace assets and improve reliability
- Minimize costs for investment and maintenance plans

It is expected that the Asset Management Program will result in improved performance of the distribution system and a reduction in the occurrence of outages caused by asset failures.

Brantford Power Inc. is committed to a methodology for Asset Management that maintains the best attributes of its existing inspection and maintenance procedures and documentation in compliance with the Distribution System Code (DSC) while incorporating new business processes to better manage available resources for data collection, analysis and assimilation.

3.0 ASSET MANAGEMENT PROGRAM STRUCTURE

UEM is working with BPI on an ongoing basis to develop and refine an Asset Management Program (AMPr) that achieves the specific goals of BPI. The heart of BPI's Asset Management Program is UEM's Optimized Decision Model (ODM). The ODM has been customized for BPI's specific requirements. The ODM is a formalized set of rules and processes which applies an Asset Management knowledge base to an Asset Database in order to develop the outputs necessary for Asset Management reports (Figure 1).

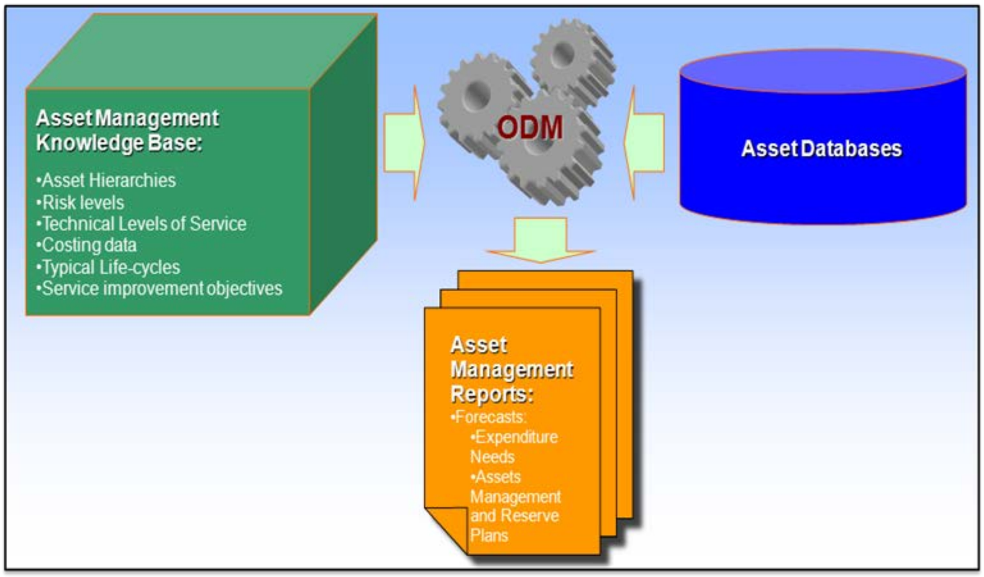


Figure 1: Optimized Decision Model (ODM) Process (UEM ©)

Optimized Decision Modeling integrates asset data and detailed technology architecture planning to ensure accurate, timely, and usable data is available for Asset Management reporting and Capital Planning. The accuracy of the Asset Database and the Asset Management Knowledge Base are integral to the usefulness of the ODM. Both the Asset Database and Asset Management Knowledge Base must be reviewed and updated on a regular basis in order to maintain and continuously improve the Asset Management Program.

3.1 ODM CAPABILITIES

The outputs of the ODM can be used to make informed decisions about the management of BPI's electrical distribution assets. The refinement of the ODM is an ongoing process. As BPI's asset data and AM knowledge base improve, the ODM will be modified accordingly.

The ODM evaluates BPI's electrical distribution assets based on the AM strategies developed as part of this project as follows:

- Level of Service Strategy
- Life Cycle Strategy
- Risk Management Strategy

BPI's AMPr uses a risk centric approach which incorporates the three AM strategies and evaluates BPI's assets using the developed Risk Matrix (Section 4.4.1). The ODM's Risk Matrix ranks the risk level of an asset according to the condition and age of the asset along its lifecycle and the degree to which the failure of the asset will have negative consequences, thereby posing the greatest risk to BPI's delivery of service. The outputs from the risk matrix are used to provide input into the creation of Capital Projects. The Capital Projects are prioritized according to risk levels and reported outages within the project area. Project costs are predicted and BPI's Yearly Capital Plan is developed by selected projects from the prioritized list to optimize discretionary capital investments.

3.2 LEVEL OF SERVICE STRATEGY

A Level of Service Strategy has been developed to ensure that a Technical Level of Service (TLoS) is being achieved which is necessary to provide the desired Customer Level of Service (CLoS). Unlike other utilities, LDC's cannot measure CLoS in terms of the quality of a tangible product that the customer is receiving. What can be measured are the duration and the frequency of the instances that the customer is not receiving electricity. While service interruptions cannot be prevented entirely, some of the identified risks of these interruptions related to the performance of the assets can be managed. The required CLoS is measured using the industry standard KPIs: SAIDI, CAIDI, and SAIFI. These indices are determined from industry best practices and are calculated using the number of service interruptions and the length of service interruptions. BPI can mitigate the risk of assets failures using the project selection and prioritization procedures laid out in this document in Sections 3.8 and *3.10*. A Service to Asset (S2A) diagram, included as Appendix A, depicts the required TLOS and how it is related to CLoS by asset class. The required TLoS for all assets evaluated by the ODM is based on condition levels and useful life estimates. Assets that do not meet the TLOS expose the organization to higher risk. These assets are not necessarily retired, but are identified as requiring risk mitigation measures. The Level of Service (LoS) strategy is tied in this way directly to the Lifecycle Management Strategy and the Risk Management Strategy.

3.3 LIFECYCLE MANAGEMENT STRATEGY

The Lifecycle Management Strategy uses asset information to plan infrastructure renewal projects based on asset condition assessments and Estimated Remaining Life (ERL). Using Year of Installation, ERL, and Condition Health Index (CHI) for each asset in the Asset Database, the probability of failure (PoF) has been calculated. PoF values are used in the ODM's risk matrix to calculate the risk level of each asset. CHI values are assigned as part of BPI's condition assessment program, outlined in the following section. In this way the Lifecycle Management Strategy is tied directly to the Risk Management Strategy and the Level of Service Strategy; those assets approaching the end of their life are identified as high in risk, and incorporated into the capital project plans.

3.3.1 CONDITION ASSESSMENT PROGRAM

Asset Management is regarded as an evolving set of practices and BPI is constantly looking for ways to improve its inspection and maintenance activities. These now include infra-red thermal imaging, targeted and comprehensive testing as well as visual inspections to provide an overall asset condition assessment. BPI is in the process of evolving this system towards better documentation, and capturing quantitative as well as qualitative condition assessment of major assets through the Asset Management Program.

BPI conducts asset condition assessments on a 3 year cycle so that the condition of all assets is assessed a minimum of once every 3 years. The ODM uses as input the most recent condition assessment for each asset. Condition inspections and assessments are performed both by in house operations crews and specialized outside contractors as appropriate. Assets which are identified as High Risk using the risk assessment methodology (Section 3.7) may be inspected on a more frequent basis and in greater detail.

As an initial step towards improved asset management practices, BPI has implemented the use of laptops in the field so that the condition assessments will be maintained in a digital format which can be linked to the asset database. Standardized Condition Health Indices (CHI) have been established and an inspection training program has been implemented to ensure consistent data entry.

The established Condition Health Indices (CHI), in Table 1 below, refer to parameters that can be checked visually through non-invasive inspection by in house field inspectors. The CHI is in turn linked with actions to be taken which may include increased frequency of inspections or more detailed inspections as shown in Table 2 below. The CHI is used as a tool that provides a reliable and consistent condition assessment and as a prioritization tool to apply further detailed inspections of assets.

Table 1: Condition Health Index – Parameters

Condition Health Index	Condition	Deterioration	Life Expectancy
5	Very Good	Some aging or minor deterioration of a limited number of Components	Recently built / renewed
4	good	Deterioration of core components	95%-75% of remaining useful life
3	Fair	Widespread deterioration of specific components	75%-50% of remaining useful life
2	Poor	Widespread serious deterioration	50%-30% of remaining useful life
1	Very Poor	Extensive serious deterioration	less than 30% of remaining useful life

Table 2: Condition Health Index – Actions

Condition Health Index	Condition	Action
5	Very Good	Normal maintenance that is mandated under the Distribution System Code of the OEB
4	good	No repair is needed. Normal maintenance that is mandated under the Distribution System Code of the OEB
3	Fair	Defects not considered to be serious or urgent (may Require more frequent inspection to keep an eye on further deterioration)
2	Poor	Defects could be serious or urgent (Require more frequent inspection to keep an eye on further deterioration)
1	Very Poor	At potential end of life. Defects are either serious and/or require urgent repair or replacement. Replace or rebuild based on detailed assessment

Moving forward, BPI is developing a GIS enabled mobile solution for condition assessments. The implementation of the mobile solution will further ensure data integrity and allow for the implementation of detailed condition assessments using the evaluation of asset components and condition criteria. Table 3 and Table 4 below are an example of condition criteria and components and their relative degrees of importance.

Table 3: Condition Criteria

Location	Asset Class	Condition Criteria/Component	Relative Degree of Importance
Overhead	Pole	Cracks	4
		Wood Pecker/ Carpenter Ant Damage	3
		Surface Rot At/Below/Above Ground Level	2
		Pole Top Feathering	2
		Mechanical Fire Damage	3
		Wood Loss	2
	Wire (Primary, Secondary)	Broken strands	2
		Clearance	4
		Sag	4
UG/OH	Switch	Deterioration of Blade/Arm/Mounting	2
		Deterioration of Connections/Terminations	3
		Deterioration of Arc Suppressors/Interrupters	2
		Deterioration of Grounding/Shunt Contact	3
		Deterioration of Lock/Handles	3
		Deterioration of Switch Insulator	2
		Mechanism Issue	2
		Operational Issue	1
	Transformer	Deterioration of Cluster-mount	4
		Deterioration of bushings	2
		Deterioration of padlocks, warning signs etc.	4
		Deterioration of transformer disconnect	3
		Extent of oil leaks	3
		Operational issue	1
		Tank corrosion, condition of paint	2
Underground	Cable (Primary, Secondary)	Number of failures per unit length of installation	1
		Insulation damage	1
		Deterioration of Terminations	3
	Structure	Structural condition of loading members	2
		Deterioration of floors, walls and ceilings	2
		Deterioration of roof and windows	3
		Environmental concerns, e.g. presence of asbestos	1
		Functional Issues	1

Table 4: Relative Degree of Importance of Condition Criteria

Relative Degree of Importance of Condition Criteria			
1 – Dominant Criteria	2 – Combinatorial Criteria	3 – Contributing Criteria	4 – No Impact
Criteria can represent Asset Health in isolation	Criteria does not reflect Asset Condition in isolation, but is a critical component in the formulation of Asset Health	Criteria is not critical to the formulation of Asset Health, but is a component in the formulation of Asset Health	Criteria does not have an impact on Asset Health

3.4 RISK MANAGEMENT STRATEGY

Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect, and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. The Risk Management Strategy provides risk framework levels for the assessment of risk for individual asset classes based on expert opinion and available data. The Risk Management Strategy uses six Risk Criteria to assess assets and determine risk levels as laid out in the Corporate Risk Policy. These criteria are:

Health and Safety
Risks related to workplace safety, worker safety, and public safety.

External Demands
Risks Related to public requirements external to the organization, and complaints not directly related to operation or performance of the existing distribution system.

Operational
Risks related to all issues that are associated with the distribution assets and their level of service.

Environmental
Risks related to environmental legislation and associated regulations, the potential of liability from an environmental stand point, and any associated legal action.

Financial
Risks related directly to financial risks and opportunities that must be addressed by the company.

Political and Regulatory
Risks related to requirements of all levels of government and associated regulatory bodies and agencies associated directly or indirectly with the operation of the company.

The Risk Assessment methodology (Section 3.7) is designed to help operators and managers determine possible vulnerable assets and identify strategies that should be considered in order to protect their integrity and the customers they serve. This framework captures the important components (risk profiles) of risk assessment according to the asset class level. Each Asset in the system is given one of the following Risk Levels and the associated mitigation measures should be in place:

- Very High priority (VH): Maximum risk mitigation measures should be in place, together with recovery plans, and availability of critical spares.
- High priority (H): Maximum risk mitigation measures should be in place providing layers of deterrence, high probability of detection, and rapid effective response. Due diligence is required including utilization of appropriate expertise and validation of assessed data.
- Moderate priority projects (M): Risk should be managed by the introduction of mitigation strategies and operational procedures.
- Low priority (L): Minimal risk mitigation measures necessary. Risk should be managed through operational procedures, or accepted as a low business risk.

The Capital Project selection and prioritization methodology (Section 3.9 and Section 3.11) focuses capital on those assets that pose the greatest risk. By selecting asset replacement/renewal projects that focus on areas containing large numbers of high risk assets it can be quantitatively shown that the projects selected are achieving the highest cost/value possible by reducing the overall system risk.

The Risk Management Strategy is consistent with BPI’s Risk Policy and manages the overall system risk.

3.4.1 *Risk Mitigation Measures*

The following are the risk mitigation methods considered by the Asset Management Program to reduce or eliminate the asset risk:

Removal of Asset

Eliminates risk by 100% over and above the new asset inherent risk. Risk priority level is changed to 'Low Risk'

Replacement of Asset

If replacement asset is new, eliminates asset risk by 100% over and above the new asset inherent risk. Risk priority level is changed to 'Low Risk' or 'Moderate Risk' according to asset criticality. If replacement asset is re-used, eliminates asset risk based on the ERL of the replacement asset. The ERL of the replacement asset must at least be sufficient to change the risk priority level to 'Moderate Risk'.

Increased maintenance

Mitigates asset risk and lowers the risk priority by at least one level. i.e. a 'Very High Risk' priority level should at least change to 'High Risk' priority level with scheduled maintenance.

Increased inspections

Asset risk priority level remains unchanged

3.5 Asset Categories

The Asset Management Program (AMPr), at this time, is limited in scope to the key assets classes for which asset attribute information and condition data is available (Table 5). In the future this list be expanded. The ODM is configured to adapt to these changes.

Table 5: Asset Classes

Asset Class	Number of Assets	Asset Map
Transformers	3284	Appendix B
Poles	10476	Appendix C
Switches	1016	Appendix D
Structures	1730	Appendix E
Primary Cables/Conductors	500308 Meters	Appendix F
Secondary Cables/Conductors	551855 Meters	Appendix G

3.6 Data Sources

The data required to run the ODM for Brantford Power comes from a variety of sources which include the G/Tech GIS system, the DAFFRON CIS System, inspection records, and expert opinion from management and operations staff. The asset data contained in these different systems and records is linked through unique asset ID's. Where Risk Assessment requires links between assets, these are determined through electrical connectivity and asset ownership relationships.

Electrical Connectivity

Electrical Connectivity refers to the electrical relationship of assets to each other within the distribution network (i.e. transformers are connected to connected wires or cables). The G/Tech Data Model contains these relationships.

Asset Ownership

Asset ownership refers to the physical relationship of assets that are associated with other assets (i.e. transformers that are located on poles or within structures). Ownership is currently assigned based on records which relate assets to the structures in which they are housed and on spatial relationships within the GIS when such records do not exist. Moving forward the ownership relationship will exist within the G/Tech Data model. The reason for this relationship is to identify assets that are at risk when the owner asset fails (i.e. a transformer that is located on a pole is at risk of failure if the pole that it is located on fails).

Data Gap Reduction

Steps have been taken in reducing gaps in the data that are present in some asset data.

Installation dates are missing for some assets. Installation dates of owned assets, as described above, have been assigned based on those assets by which they are owned (assets on poles are assigned the installation date of the pole on which they are mounted) where those assets are missing installation data.

Location Data has also been found to be lacking for a number of assets. In these cases the location of the assets which held ownership over the asset in question, or which the asset in question held ownership over is assigned (e.g. structures are assigned the location of the transformers which they house).

Data and data connectivity required to calculate the criticality is currently unavailable for some asset classes. The criticality of transformers is being leveraged through electrical connectivity and asset ownership relationships to assign criticality in these cases.

As part of the ongoing Asset Management improvements underway at BPI, projects are planned which will close the identified data and data connectivity gaps.

3.7 Risk Assessment

Risk Assessment is performed using a Risk Matrix. The Risk Matrix ranks assets according to the likelihood of an event or Probability of Failure (PoF), and the potential consequences of an event or Consequence of Failure (CoF) in order to determine the Risk Level (Figure 2).

Condition Health Index (CHI)		Estimated Remaining Life Percentage (ERL %)	Probability of Failure (PoF)		Consequence of Failure (CoF)			
					0-20	>20 – 40	>40-60	>60-100
Score	Definition		Score	Definition	Minor	Moderate	Major	Catastrophic
1 & 2	Very Poor Poor	0-100	4	Almost Certain	H	H	VH	VH
3 & 4	Moderate Good	3: 0-100 4: 0-50	3	Likely	M	H	H	VH
4	Good	50-100	2	Somewhat Likely	L	M	M	H
5	Excellent	0-100	1	Unlikely	L	L	M	M

Figure 2: Risk Matrix

3.7.1 *Probability of Failure*

The Probability of Failure (PoF) is the first of two primary values used in the Risk Matrix. PoF represents the likelihood that an asset may fail. PoF is calculated based on two secondary values: the Condition Health Index (CHI) and Estimated Remaining Life (ERL). These values are described in detail below.

CHI: CHI represents the condition of the asset as assessed from field inspection. The CHI's scale is based on 1-5. "1" represents very poor and "5" represents excellent condition.

ERL%: The ERL% is the estimated remaining life of an asset. It is calculated according to the following equation:

$$\mathbf{ERL}(\%) = \left[\frac{\mathbf{ESL-Age}}{\mathbf{ESL}}\right] \text{....Equation 1}$$

Where: **ERL** is the Estimated Remaining Life of an asset, **ESL** is the Estimated Service Life, and **Age** is the time between the date of installation and the date the asset is analyzed.

The relation between PoF, CHI and ERL is as follows:

- When the asset condition is very poor (CHI=1) or poor (CHI=2), regardless of the Estimated Remaining Life (ERL), the probability of failure (PoF) is Almost certain and given a PoF score of 4.

- When the asset condition is moderate (CHI=3), regardless of the Estimated Remaining Life (ERL), the probability of failure (PoF) is Likely and given PoF a score of 3.
- When the asset condition is good (CHI=4) and the ERL (%) is less than 50%, the probability of failure (PoF) is Likely and given a PoF score of 3.
- When the asset condition is good (CHI=4) and the ERL (%) is more than 50%, the probability of failure (PoF) is somewhat likely and given PoF a score of 2.
- When the asset condition is excellent (CHI=5), regardless of the Estimated Remaining Life (ERL), the probability of failure (PoF) is Unlikely and given a PoF score of 1.

In the absence of recent condition data for an asset, the Estimated Remaining Life (ERL) is applied to determine the replacement dates (Figure 3)**.** Where the asset condition data provided by BPI and analyzed by UEM was not sufficient to determine PoF based on CHI and ERL transformer condition (CHI) was leveraged to assess the condition of associated assets based on electrical connectivity and geographical proximity

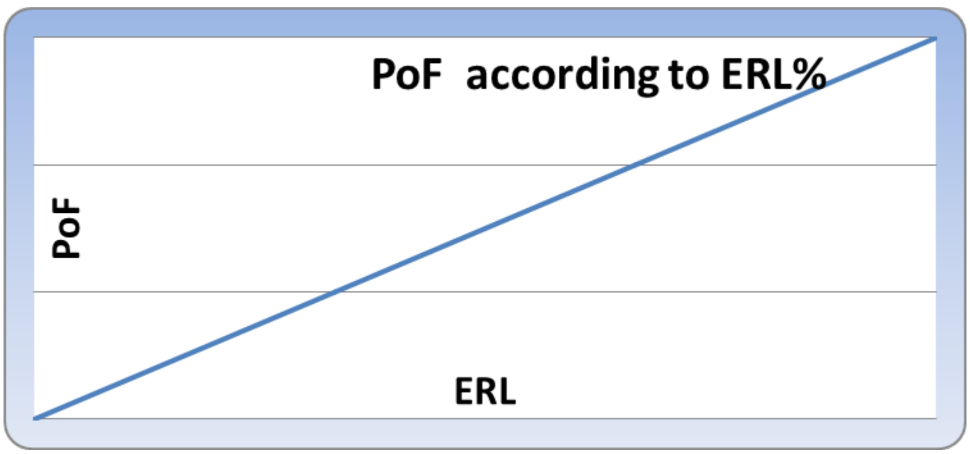


Figure 3: PoF according to ERL%

3.7.2 *Consequence of Failure and Criticality*

Consequence of Failure (CoF) is the second of the two primary values used in the Risk Matrix. CoF represents the severity of the consequences that will be the result of the failure of an asset. The 6 risk criteria defined above in Section 4.3 (Health and Safety, External Demands, Operational, Environmental, Financial, Political/Regulatory), were used to evaluate a set of Critical Factors developed in consultation with BPI operations staff and management in order to determine the criticality and Consequence of Failure (CoF) of an asset; the set of risk factors is different for each asset class (Appendix H).

CoF: The Consequence of Failure is divided into four categories as follows and as shown in Figure 3 on page 12:

- The consequence of failure is minor when its value is (0 -20)
- The consequence of failure is moderate when its value is (>20-40)
- The consequence of failure is major when its value is (>40-60)
- The consequence of failure is catastrophic when its value is (>60-100)

The first three categories have a weighting factor of 20% each, while the “Catastrophic” category is given weighting factor of 40%. These ranges were determined through statistical analysis of available asset data after several iterations of the model. The above categories and ranges ensure the grouping of assets with similar condition, criticality and age characteristics with minimum overlap of risk levels, thereby creating distinct risk profiles based on the unique composition of BPI’s asset base.

3.7.3 ASSET RISK LEVELS

The Risk Matrix is divided into 16 cells according to the 4 possible PoF values and the 4 possible CoF ranges. The distribution of Risk Levels in the matrix is in a diagonal progression from Low Risk in the lower left corner, where the PoF is “Unlikely” and the CoF is “Minor”, to High Risk in the upper right corner, where PoF is “Almost certain” and CoF is “Catastrophic”. There are 3 cells each for “Very High” and “Low” risk, and 5 cells each for “High” and “Moderate” risk. The matrix is arranged in such a way that the distribution of cells is as follows according to the Probability of Failure:

- When the PoF is 4, the asset is “Almost certain” to not to meet the required TLoS. Therefore, no asset with a PoF of 4 may be assigned a Risk Level lower than “High” and assets with a CoF of “Major” or “Catastrophic” are assigned a Risk Level of “Very High”
- When the PoF is 3, the asset is “Likely” to not to meet the required TLoS. Therefore, the Risk Levels range from “Moderate” to “Very High” according to CoF values.
- When the PoF is 2, the asset is “Somewhat Likely” to not to meet the required TLoS. Therefore, the Risk Levels range from “Low” to “High” according to CoF values.
- When the PoF is 1, the asset is “Unlikely” to not to meet the required TLoS. Therefore, no asset may be assigned a Risk Level higher than “Moderate” and asset with a CoF of “Minor” and “Moderate” are assigned a Risk Level of “Low”

3.7.4 ASSET RISK SCORES

Risk Scores are calculated as the product of PoF and Criticality. Since PoF is always a value between 1 and 4 and Criticality is always a value between 1 and 100, the Risk Score of an asset will be between 1 and 400. Risk Scores are used to help prioritize projects as described later in Section 4.7. Risk scores do not correlate mathematically with the Risk Levels which are a logical (combinational) outcome of the Risk Matrix.

3.7.5 EXAMPLES OF ASSET CRITICALITY

CRITICALITY OF TRANSFORMERS

The Criticality of transformers is determined based on 8 Critical Factors. Each Critical Factor is weighted according to the 6 Risk Criteria. Table 6 shows the Critical Factors of transformers with their weight and probability.

Table 6: Critical Factors of Transformers

Critical Factors	Risk Criteria (0-4)						Critical Factor Weight (0-24)	Critical Factor Probability (0-4)
	Health & Safety	External Demand	Operational	Environmental	Financial	Political & Regulatory		
Rusting due to road salt	2	0	3	2	3	0	10	2
Damage from const. vehicle, public vehicles	3	0	3	2	3	0	11	4
Short circuit or insulation damage from water penetration	0	0	2	2	2	0	6	4
Electric shock to public due to contact	2	2	3	4	2	2	15	4
Short circuit due to vegetation growth	1	0	2	0	1	0	4	2
Damage to bushings and spades due to excessive cable downward loading	0	0	2	0	3	0	5	2
Damage to 4Kv transformers due to failure of old customer owned cables	0	3	4	0	4	0	11	3
Critical Customers (Number of Customers)	4	4	4	4	4	4	24	4
Total	12	9	23	14	22	6	86	
Total (%)	14%	10%	27%	16%	26%	7%	100%	
0 = N/A 1 = Minor 2 = Moderate 3 = Major 4 = Catastrophic								

Every transformer in the database has been given a score for each of these Critical Factors based on the location in relation to the road network, the location within the distribution network, and the type of transformer as depicted in Table 7:

Table 7: Critical Factor Scoring for Transformers

Critical Factor	Data Source	Data Field	Scoring						
Rusting due to road salt	Road in GIS	AADT (min)	0	1000	3000	10000			
		AADT (max)	1000	3000	10000	100000			
		risk score	25	50	75	100			
Damage from const. vehicle, public vehicles	Road in GIS	Road description	Arterial	HWY403	Local	Major Arterial	Major Collector	Minor Arterial	Minor Collector
		risk score	80	100	20	100	60	80	40
Electric shock to public due to contact	DAFFRON	XFRM Type	Pad mounted	Submersible	Pole mount	Mini pad mount			
		risk score	0	100	0	0			
Short circuit due to vegetation growth	DAFFRON	XFRM Type	Pad mounted	Submersible	Pole mount	Mini pad mount			
		risk score	50	50	100	50			
Short circuit or insulation damage from water penetration	DAFFRON	XFRM Type	Pad mounted	Submersible	Pole mount	Mini pad mount			
		risk score	0	100	50	0			
Damage to 4Kv transformers due to failure of old customer owned cables	DAFFRON	Voltage	4 kilo volt	other					
		risk score	100	0					
Damage to bushings and spades due to excessive cable downward loading	DAFFRON	Loading Capacity % (Min)	0	11	71	101			
		Loading Capacity % (Max)	10	70	100	1000			
		risk score	0	25	75	100			
Critical Customers (Number of Customers)	DAFFRON	Customers (Min)	0	10	50	75			
		Customers (Max)	10	50	75	100			
		risk score	25	50	75	100			

In order to calculate the criticality of a transformer, the following Equation is used:

$$\mathrm{Cr}_{\mathrm{transformer}} = \sum_{j=1}^{n} I_j \times \left\{ \frac{(\text{Critacal Factor Weight} \times \text{Critical Factor Probability})_j}{\sum_{j=1}^{n} (\text{Critical Factor Weight} \times \text{Critical Factor Probability})_j} \right\}$$

Equation 2

Where: **Cr**: Criticality; $\mathbf{Cr}_{\mathbf{transformer}}$: Criticality of an individual transformer; **j**: Critical Factor; **I**: Critical Factor score (1-100); **n**: Maximum Number of Critical Factors.

Table 8 shows an example of this calculation for a hypothetical transformer, transformer (i):

Table 8: Example of Transformer Criticality Calculation

No.	Critical Factor	Critical Factor Weight (0-24)	Critical Factor Probability (0-4)	Critical Factor Importance (0-98)	Critical Factor Asset Score (0-100)	Criticality of Factor to Asset
Col.1	Col.2	Col.3	Col.4	Col.5= (Col.3 *Col.4)	Col.6	Col.7 = (Col.5 * Col.6) /sum(Col.5)
1	Rusting due to road salt	10	2	20	80	6.48
2	Damage from const. vehicle, public vehicles	11	4	44	50	8.91
3	Short circuit or insulation damage from water penetration	6	4	24	50	4.86
4	Electric shock to public due to contact	15	4	60	0	0.00
5	Short circuit due to vegetation growth	4	2	8	100	3.24
6	Damage to bushing/spades due to excessive cable downward loading	5	2	10	0	0.00
7	Damage to 4Kv transformers due to failure of old customer owned cables	11	3	33	0	0.00
8	Critical Customers	24	2	48	25	4.86
Total: Transformer Criticality						28.34

The criticality of the hypothetical transformer (i) is equal to 28.34 or “Moderate”.

Due to gaps in data and data connectivity the criticalities of switches, structures, primary cables/conductors, and secondary cables/conductors are currently assumed to be the same values of the connected transformers. As data and data connectivity improve each asset will be assigned a criticality based on specific asset class related criteria and factors.

Criticality of Poles

The criticality of poles is determined based on 5 risk events. Each risk event is rated according to the 6 risk criteria. Table 9 shows the critical factors of poles with their risk event weight and probability of event.

Table 9: Critical Factors of Poles

Critical Factor	Risk Criteria (0-4)						Critical Factor Weight (0-24)	Critical Factor Probability (0-4)
	Health & Safety	External Demand	Operational	Environmental	Financial	Political & Regulatory		
Ants Infestation Damage	1	0	1	0	1	0	3	4
Weak Wood Due to Rot	2	0	2	0	2	0	6	4
Wood Pecker Damage	0	0	1	0	0	0	1	1
Flood Waters Damage	0	0	2	0	1	0	3	1
Transformer Mounted	3	0	3	0	3	0	9	4
Total	6	0	9	0	7	0	22	
Total (%)	27%	0%	41%	0%	32%	0%	100%	
0 = N/A 1 = Minor 2 = Moderate 3 = Major 4 = Catastrophic								

Table 10 depicts the hierarchy of critical parameters for poles. The hierarchy in Table 7 is divided into two levels; the first level represents the Critical Factors; while the second level represents the Critical Criteria of each Critical Factor. Critical Factor weights and probability are identified for each factor.

Table 10: Critical Criteria of Poles

Critical Factor	Ants Infestation Damage	Weak Wood Due to Rot	Wood Pecker Damage	Flood Waters Damage	Transformer Mounted
Critical Factor Weight	3	6	1	3	9
Critical Factor Probability	4	4	1	1	4
Critical Criteria	ants infestation	weak wood surface rot	wood pecker treatment length	flood waters treatment length	transformer mounted
	ants treatment length	weak wood pole species	wood pecker treatment type	flood waters material	
	ants treatment type	weak wood material	wood pecker material		
	ants material				

Every pole in the database has been given a score for each of these criteria based on the pole inspection reports, the pole treatment type, and the physical relationship to transformers. The scoring criteria are depicted in Table 11:

Table 11: Critical Factor Scoring for Poles

SCORE NAME	DATA SOURCE	DATA FIELD	SCORING			
ants infestation	Pole Inspection	Mech Condition	NULL	Carpenter ants damage - Slight	Carpenter ants damage - Moderate	Carpenter ants damage - Extensive
		Value	20	75	100	100
ants treatment length	Pole Inspection	Treat Length	Full	Butt		
		Value	0	50		
ants treatment type	Pole Inspection	Treat Type	NULL	CCA, Creo, Penta, S, Salt	C, P	
		Value	0	20	75	
ants material	Pole Inspection	Material	Wood			
		Value	20			
weak wood surf rot	Pole Inspection	Mech Condition	NULL	Surface Rot below GL - Slight	Surface Rot below GL - Moderate	Surface Rot below GL - Extensive
		Value	20	50	75	100
weak wood pole species	Pole Inspection	Pole Species	NULL, SP, DF	JP, Pine, WC	Cedar	
		Value	0	25	50	
weak wood material	Pole Inspection	Material	Wood			
		Value	20			
wood pecker treatment length	Pole Inspection	Treat Length	Full	Butt		
		Value	0	50		
wood pecker treatment type	Pole Inspection	Treat Type	NULL, CCA, Creo, Penta, S, Salt	C, P		
		Value	0	75		
flood waters treatment length	Pole Inspection	Treat Length	Full	Butt		
		Value	0	50		
flood waters material	Pole Inspection	Material	Wood			
		Value	20			
transformer mounted	DAFFRON & GIS JOIN	XFMR TYPE	POLEMOUNT			
		Value	100			

The criticality of a pole is calculated as follows:

$$I_j = Max.\,[(k)_i^n]\text{......... } \textbf{Equation 3}$$

$$Cr_{pole} = \sum_{j=1}^{m} I_j \times \{\frac{(\text{Critical Factor Weight} \times \text{Critical Factor Probability})_j}{\sum_{j=1}^{m}(\text{Critical Factor Weight} \times \text{Critical Factor Probability})_j}\}\text{......} \textbf{Equation 4}$$

Where:

Cr: Criticality; I_j: Critical Factor Score; $\mathbf{Cr_{pole}}$: Criticality index of an individual pole; **k**: Critical Criteria Score; **n**: Maximum number of Critical Criteria of each Critical Factor; **j**: Critical Factor; **m**: maximum number of Critical Criteria.

The criticality of a hypothetical pole, pole (i), based on data observation is equal to 81.91 (Table 12):

Table 12: Criticality Calculation of a Pole

Critical Factor	Critical Criteria	Critical Criteria Score	Critical Factor Score (Maximum Critical Criteria)	Critical Factor Weight	Critical Factor Probability	Critical Factor Importance (Weight * Probability)	Criticality (Critical Factor Score * Critical Factor Importance /Sum of Critical Factor Importance)
Ants infestation	ants infested	100	100	3	4	12	15.79
	ants treatment length	50					
	ants treatment type	75					
	ants material	20					
Weak Wood	weak wood surface rot	20	50	6	4	24	15.79
	weak wood pole species	50					
	weak wood material	20					
Wood Pecker	wood pecker treatment length	50	75	1	1	1	.99
	wood pecker treatment type	75					
	wood pecker material	20					
Flood Waters	flood waters treatment length	50	50	3	1	3	1.97
	flood waters material	20					
Transformer Mounted	transformer mounted	100	100	9	4	36	47.37
Total: Pole Criticality Index							81.91

The criticality of Pole (i) is located within the range of 60-100, which means that the consequence of failure is catastrophic. The expected action of Pole (i) is one of the following: mitigate, high priority, or fix now; the final mitigation decision is determined based on the probability of failure, which is a function of condition health index (CHI) as shown in Figure 3, Page 13.

3.7.6 ODM Asset Risk Statistics

The Risk Assessment Methodology as described in Section 3.7 has been applied to BPI's asset data. The following sections summarize the distribution by asset class.

The confidence level of the results, based on UEM's assessment of the quality of the data, for transformers and poles is high, however for the rest of the asset classes a significant amount of work needs to be done over time to upgrade the data.

Transformers

Of the 3284 transformers analyzed, 3192 (96.04%) had sufficient data with which to determine Risk Levels. 139 were found to be "Very High Priority", 518 were found to be "High Priority", 1045 were found to be "Moderate Priority", and 1452 were found to be "Low Priority". Figure 4 and Figure 5 show the distribution of the assets by number and percent. Appendix B shows the location of the assets and their Risk Levels.

Count			Consequence of Failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	123	35	121	7
	3	Likely	645	293	68	11
	2	Somewhat Likely	1224	382	21	2
	1	Unlikely	155	80	1	2

Figure 4: Risk Level Distribution of Transformers

Percentage			Consequence of failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	3.85%	1.19%	4.10%	0.41%
	3	Likely	20.21%	9.18%	2.13%	0.44%
	2	Somewhat Likely	38.35%	11.97%	0.66%	0.06%
	1	Unlikely	4.86%	2.51%	0.03%	0.06%

Figure 5: Risk Level Distribution of Transformers by Percent

POLES

Of the 10476 poles analyzed, 10476 (100.00%) had sufficient data with which to determine Risk Levels. 75 were found to be "Very High Priority", 1627 were found to be "High Priority", 3150 were found to be "Moderate Priority", and 5624 were found to be "Low Priority". Figure 6 and Figure 7 show the distribution of the assets by number and percent. Appendix C shows the location of the assets and their Risk Levels.

Count			Consequence of Failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	0	433	11	10
	3	Likely	1	873	0	54
	2	Somewhat Likely	36	2255	1	321
	1	Unlikely	431	5157	19	874

Figure 6: Risk Level Distribution of Poles

Percentage			Consequence of failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	0.00%	4.13%	0.11%	0.10%
	3	Likely	0.01%	8.33%	0.00%	0.52%
	2	Somewhat Likely	0.34%	21.53%	0.01%	3.06%
	1	Unlikely	4.11%	49.23%	0.18%	8.34%

Figure 7: Risk Level Distribution of Poles by Percent

Switches

Of the 1016 switches analyzed, 997 (98.13%) had sufficient data with which to determine Risk Levels. 7 were found to be "Very High Priority", 140 were found to be "High Priority", 360 were found to be "Moderate Priority", and 388 were found to be "Low Priority". Figure 8 and Figure 9 show the distribution of the assets by number and percent. Appendix D shows the location of the assets and their Risk Levels.

Count			Consequence of Failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	8	0	0	3
	3	Likely	102	108	21	4
	2	Somewhat Likely	379	337	23	3
	1	Unlikely	7	2	0	0

Figure 8: Risk Level Distribution of Switches

Percentage			Consequence of failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	0.80%	0.00%	0.00%	0.30%
	3	Likely	10.23%	10.83%	2.11%	0.40%
	2	Somewhat Likely	38.01%	33.80%	2.31%	0.30%
	1	Unlikely	0.70%	0.20%	0.00%	0.00%

Figure 9: Risk Level Distribution of Switches by Percent

Structures

Of the 1730 structures analyzed, 1688 (97.57%) had sufficient data with which to determine Risk Levels. 111 were found to be "Very High Priority", 261 were found to be "High Priority", 140 were found to be "Moderate Priority", and 842 were found to be "Low Priority". Figure 10 and Figure 11 show the distribution of the assets by number and percent. Appendix E shows the location of the assets and their Risk Levels.

Count			Consequence of Failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	120	19	85	13
	3	Likely	334	71	50	13
	2	Somewhat Likely	747	117	19	1
	1	Unlikely	76	19	2	2

Figure 10: Risk Level Distribution of Structures

Percentage			Consequence of failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	7.11%	1.13%	5.04%	0.77%
	3	Likely	19.79%	4.21%	2.96%	0.77%
	2	Somewhat Likely	44.25%	6.93%	1.13%	0.06%
	1	Unlikely	4.50%	1.13%	0.12%	0.12%

Figure 11: Risk Level Distribution of Structures by Percent

PRIMARY CABLES

Of the 500308 meters of Primary Cables analyzed, 433739 meters (86.69%) had sufficient data with which to determine Risk Levels. 2324 meters were found to be “Very High Priority”, 51340 meters were found to be “High Priority”, 89790 meters were found to be “Moderate Priority”, and 264214 meters were found to be “Low Priority”. Figure 12 and Figure 13 show the distribution of the assets by number of meters and percent. Appendix F shows the location of the assets and their Risk Levels.

Length in Meters			Consequence of Failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	13503	5858	21928	6532
	3	Likely	124480	80646	14717	4002
	2	Somewhat Likely	128858	79893	1609	323
	1	Unlikely	17714	14300	0	219

Figure 12: Risk Level Distribution of Primary Cables by Length in Meters

Percentage of Total Length			Consequence of failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	2.62%	1.14%	4.26%	1.27%
	3	Likely	24.19%	15.67%	2.86%	0.78%
	2	Somewhat Likely	25.04%	15.53%	0.31%	0.06%
	1	Unlikely	3.44%	2.78%	0.00%	0.04%

Figure 13: Risk Level Distribution of Primary Cables by Percent of Total Length

Secondary Cables

Of the 551855 meters of Secondary Cables analyzed, 509979 meters (92.41%) had sufficient data with which to determine Risk Levels. 2567 meters were found to be "Very High Priority", 66172 meters were found to be "High Priority", 66115 meters were found to be "Moderate Priority", and 291051 meters were found to be "Low Priority". Figure 14 and Figure 15 show the distribution of the assets by number of meters and percent. Appendix G shows the location of the assets and their Risk Levels.

Length in Meters			Consequence of Failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	8137	0	0	0
	3	Likely	83873	50371	7459	2567
	2	Somewhat Likely	143610	60899	2966	406
	1	Unlikely	96792	50650	1480	771

Figure 14: Risk Level Distribution of Secondary Cables by Length in Meters

Percentage of Total Length			Consequence of failure (CoF)			
			0-20	20 - 40	40- 60	60 - 100
			Minor	Moderate	Major	Catastrophic
Probability of Failure (PoF)	4	Almost Certain	1.60%	0.00%	0.00%	0.00%
	3	Likely	16.45%	9.88%	1.46%	0.50%
	2	Somewhat Likely	28.16%	11.94%	0.58%	0.08%
	1	Unlikely	18.98%	9.93%	0.29%	0.15%

Figure 15: Risk Level Distribution of Secondary Cables by Percent of Total Length

3.8 PROJECT SELECTION PROCESS

A process has been developed for capital project selection and prioritization. Capital projects are selected based on the geographical location and the assessed risk levels of assets. GIS software is used to map the location of all assets. All assets identified as "Very High Risk" are selected to be included in the projects. Project boundaries are determined manually based on geographical groupings of those assets identified as "Very High Risk" and those identified as "High Risk" which are in close geographical proximity to the "Very High Risk" assets. Areas where capital projects are known to have been recently completed, but where the data has not yet been updated as part of the 3 year condition assessment program are removed from consideration. Projects are prioritized based on the total risk scores of the assets within the project boundary and the total number of outages that have been reported in the last 10 years within the project boundary.

Both project selection and project prioritization results are based on the current available data. As data is updated the capital project selection and prioritization processes will improve accordingly.

3.8.1 SELECTED CAPITAL PROJECTS

Using the project selection method described above, projects were selected by the UEM project team in consultation with BPI staff.

Table 13 below lists these projects. Figure 16 identifies the locations of selected projects, while Figure 17, Figure 18 and Figure 19 depict the total cost, risk, and number of reported outages for each project in relation to each other. Appendix I contains a map showing the location of the projects in relation to those assets identified as "High" and "Very High" risk.

Table 13: Selected Projects

Project #	Project Name	Total Assets	Reported Outages	Total Risk	Estimated Cost
1	Dalhousie Street (Clarence to Stanely)	78	26	10285	$926,000.00
3	Mohawk Street Townhouses	10	0	2368	$79,296.46
4	Elgin Street Townhouses / Varga & Frank	4	9	589	$50,488.15
5	Stanley Street Townhouses / Stanley Manor	9	3	2332	$111,359.75
6	Campbell Street Townhouses	5	1	935	$58,656.74
7	Henry Street / Town & Country Townhouses	5	1	783	$55,034.45
8	Henry Street Townhouses 154-164	7	2	1802	$80,467.55
9	Brant Avenue	118	63	18827	$711,000.00
10	Farringford Drive & Pusey Boulevard	81	20	14100	$385,944.28
11	Forest Road / Keeler Place / Marvin Avenue	31	5	5422	$193,025.50
15	Darling Street / Twelfth Avenue	4	0	941	$50,184.28
17	Oak Hill Drive Townhouses	8	4	1124	$71,490.98
18	James Avenue / Grey Street	17	2	3147	$158,700.63
19	Metcalf Crescent	22	10	4728	$148,690.37
20	Holbor Street / Orchard Avenue	6	0	1054	$52,014.07
21	Joysey Street / Ariel Street	5	2	938	$28,908.58
23	North Park Street / Memorial Drive / Blackfriar Lane	41	24	7054	$274,116.00
24	Memorial Drive / Powerline Road	89	18	12968	$265,586.38
25	Lynden Road / Roy Boulevard	3	0	782	$184,740.45
27	Forbes Crescent	4	0	947	$50,184.28
28	Colborne Street West / Oak Street	7	0	1267	$41,017.51
31	Canada Court	6	0	1113	$35,235.54
32	Colborne St / Clara Crescent	2	0	460	$21,784.18
33	Alpha Crescent	5	0	927	$29,879.66
35	Dunsdon Street & Sheena Avenue	6	4	1158	$25,865.00
36	Scarfe Gardens	8	7	1367	$73,573.76
37	Allensgate Drive / Myrtleville Drive	51	11	4535	$319,585.49
38	Downtown King Street / Queen Street	47	9	7677	$285,467.75
39	Downtown Market Street	47	6	8931	$233,219.39
40	Downtown Charlotte Street	6	0	891	$90,027.83
41	Colborne Street (Clarence to Stanley)	70	31	6979	$470,000.00

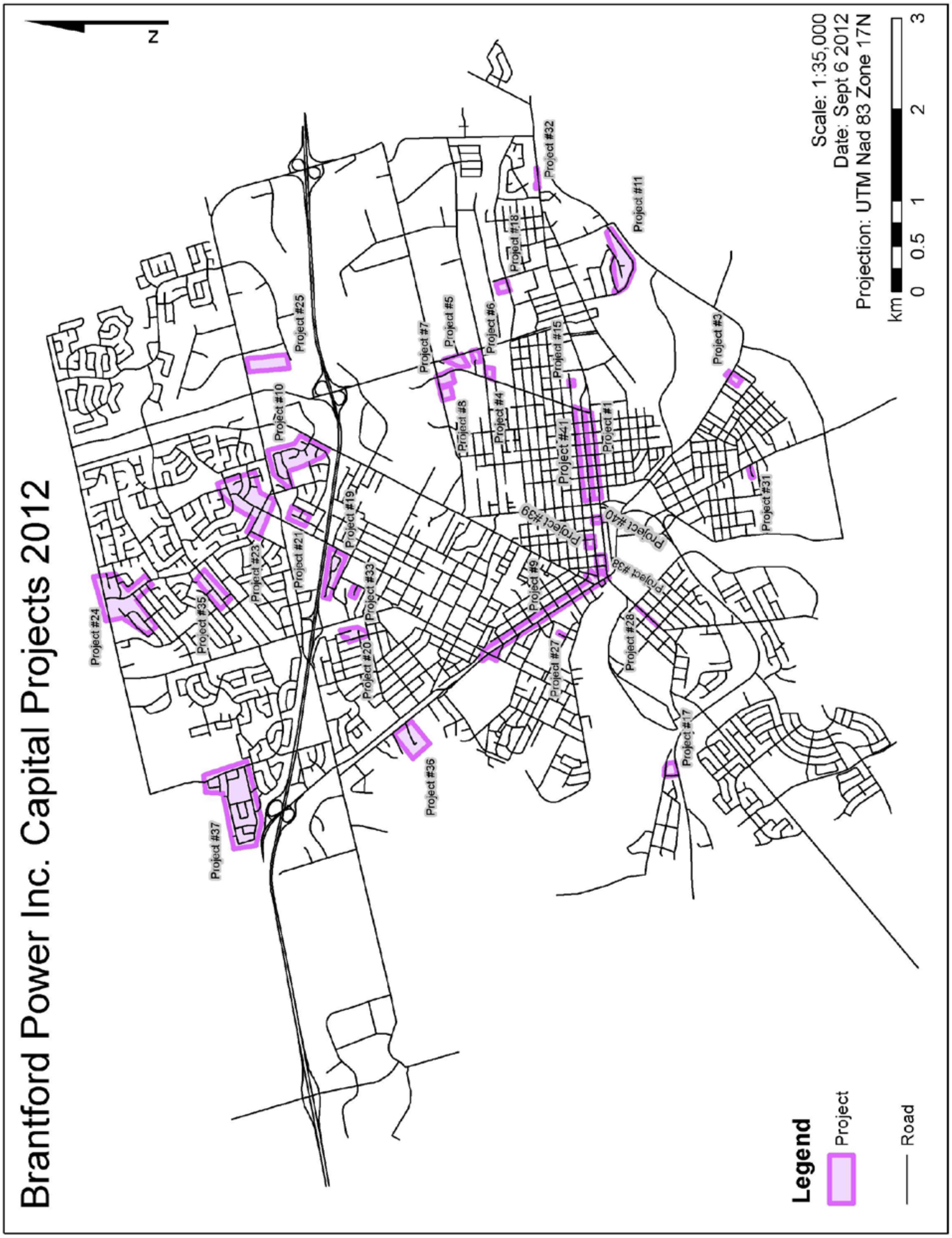


Figure 16: Map of Project Locations

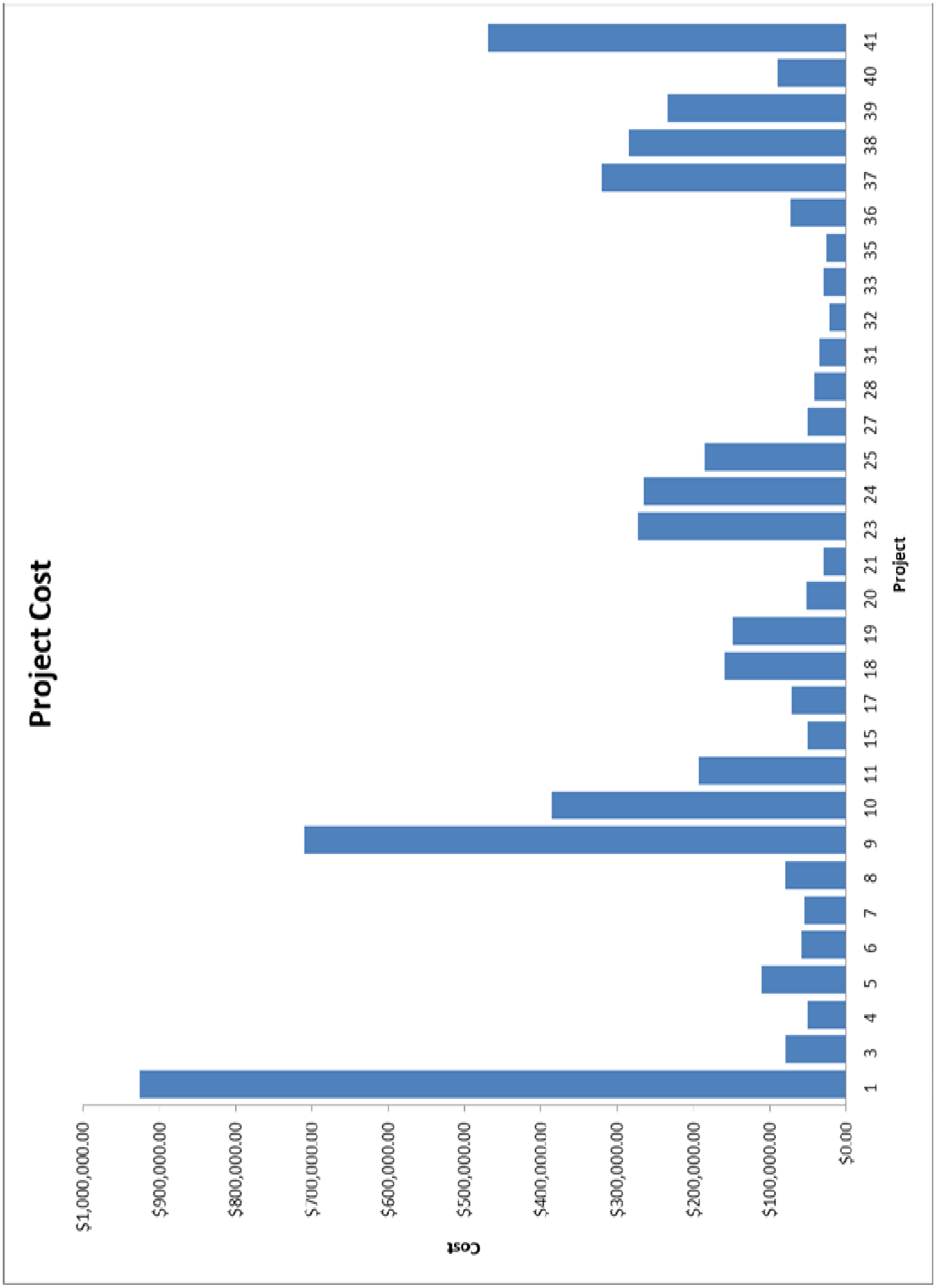


Figure 17: Total Estimated Cost by Project

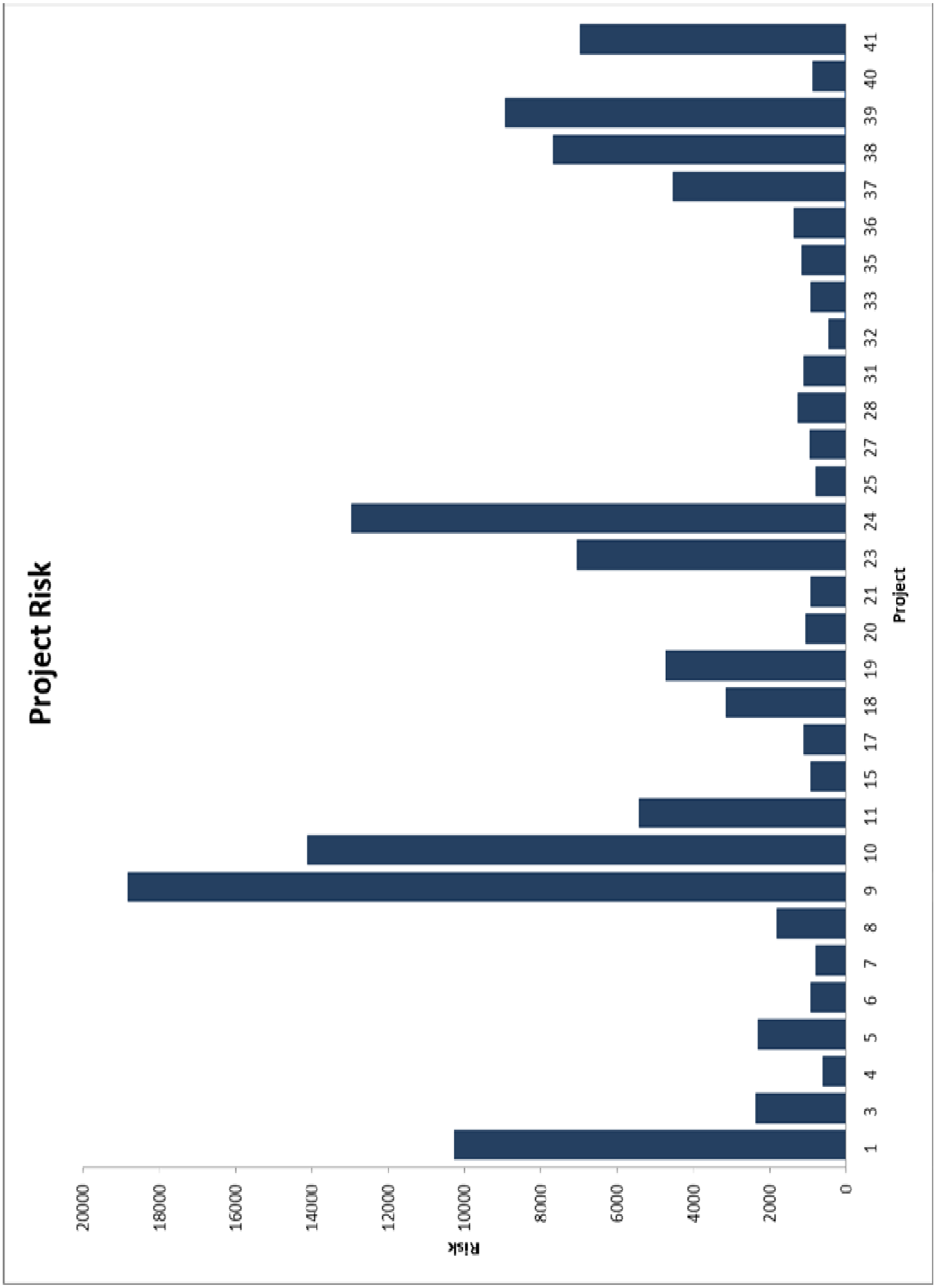


Figure 18: Risk by Project

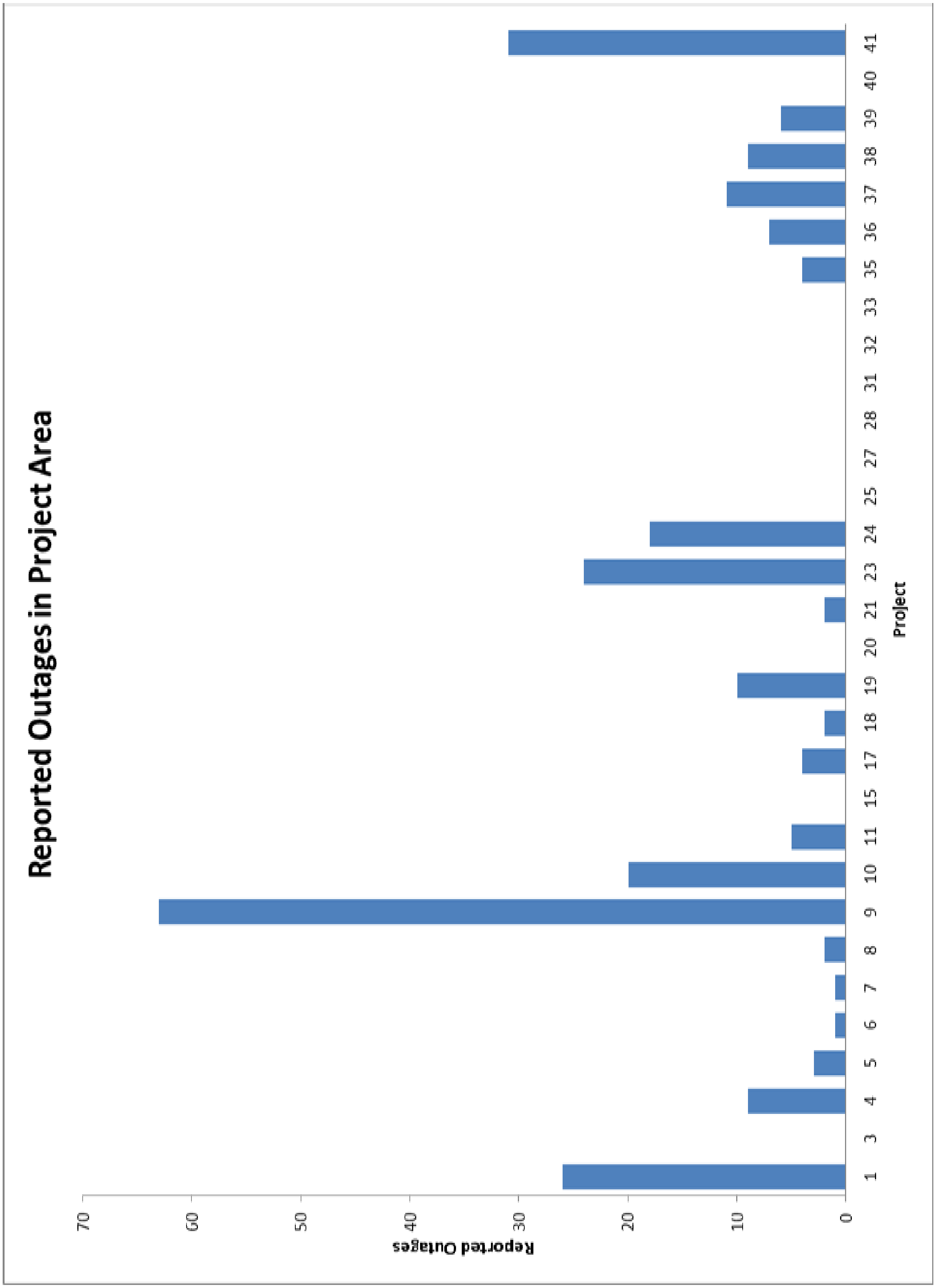


Figure 19: Reported Outages by Project Area

3.9 Project Costing Estimations

Estimated projects costs are determined based on the replacement of Very High Risk and High Risk assets in accordance with BPI's existing practice of replacing only those assets in poor repair. Appendix J contains the full costing details by asset. The project cost estimation methodology has been tested against known project costs for completed projects. Engineering and inspection costs are calculated as percentages of the asset replacement costs using Equation 5 and Equation 6 below and are added to the asset costs. The equations for determining the inspection and engineering costs were developed based on known inspection and engineering costs of past projects.

$$Inspection\ Cost = \frac{78.837 \times \frac{Cost^{-0.195}}{100}}{\left(1 - 78.837 \times \frac{Cost^{-0.195}}{100}\right) * Cost}$$ .....Equation 5

$$Engineering\ Cost = \frac{503.91 \times \frac{Cost^{-0.32}}{100}}{\left(1 - 503.91 \times \frac{Cost^{-0.32}}{100}\right) * Cost}$$ .....Equation 6

Projects that require a complete redesign, rather than simply the replacement of assets, are costed on an individual basis by the Engineering Department. This determination is made at the discretion of the Engineering Department. The project costing estimation methodology is used for modeling purposes. Actual project costing is done as part of the budget process.

3.10 Capital Project Prioritization Process

Projects are prioritized in order to produce the greatest reduction in risk across the system and have the greatest benefit to the TLOS. The sum of the risk index of the assets included in the project is combined with the total number of outages that have occurred within the project boundary over the last 10 years in order to develop the order of priority for projects.

$$P_i = \frac{\left(\frac{R_i}{\left(\sum_i^n R\right)}\right) \times WR + \left(\frac{O_i}{\left(\sum_i^n O\right)}\right) \times WO}{WR + WO}$$ ......Equation 7

Where: **P**: Project Priority; **R**: Project Risk; **O**: Outages in Project Area; **WR**: Risk Weight; **WO**: Outage Weight

The Risk Weight and Outage Weight are determined based on expert opinion and tested to ensure that that those projects that are deemed of higher importance by experts are highest on the priority list.

By using this method, a preference is given to higher risk projects and projects that address areas that have historically had a negative impact on SAIDI CAIDI SAIFI. The yearly capital project list is developed by selecting projects in order of priority until a budget limit is reached. This process will allow a number of larger projects and a number of smaller projects to be budgeted for each year.

3.10.1 PRIORITIZED PROJECTS

The projects selected under 3*.9 Selected Projects* have been prioritized according to the process described above. The projects are shown in Table 14 below.

Table 14: Prioritized Projects

Order of Priority	Project #	Project Name	Total Assets	Reported Outages	Total Risk	Project Priority Score	Estimated Cost
1	9	Brant Avenue	118	63	18827	20.6	$711,000.00
2	41	Colborne Street (Clarence to Stanley)	70	31	6979	9.4	$470,000.00
3	1	Dalhousie Street (Clarence to Stanely)	78	26	10285	9.3	$926,000.00
4	10	Farringford Drive & Pusey Boulevard	81	20	14100	9.1	$385,944.28
5	24	Memorial Drive / Powerline Road	89	18	12968	8.3	$265,586.38
6	23	North Park Street / Memorial Drive / Blackfriar Lane	41	24	7054	7.8	$274,116.00
7	38	Downtown King Street / Queen Street	47	9	7677	4.5	$285,467.75
8	39	Downtown Market Street	47	6	8931	4.2	$233,219.39
9	37	Allensgate Drive / Myrtleville Drive	51	11	4535	4.0	$319,585.49
10	19	Metcalf Crescent	22	10	4728	3.8	$148,690.37
11	11	Forest Road / Keeler Place / Marvin Avenue	31	5	5422	2.9	$193,025.50
12	4	Elgin Street Townhouses / Varga & Frank	4	9	589	2.3	$50,488.15
13	36	Scarfe Gardens	8	7	1367	2.1	$73,573.76
14	18	James Avenue / Grey Street	17	2	3147	1.5	$158,700.63
15	5	Stanley Street Townhouses / Stanley Manor	9	3	2332	1.4	$111,359.75
16	35	Dunsdon Street & Sheena Avenue	6	4	1158	1.3	$25,865.00
17	17	Oak Hill Drive Townhouses	8	4	1124	1.3	$71,490.98
18	8	Henry Street Townhouses 154-164	7	2	1802	1.0	$80,467.55
19	21	Joysey Street / Ariel Street	5	2	938	0.8	$28,908.58
20	3	Mohawk Street Townhouses	10	0	2368	0.7	$79,296.46
21	6	Campbell Street Townhouses	5	1	935	0.5	$58,656.74
22	7	Henry Street / Town & Country Townhouses	5	1	783	0.5	$55,034.45
23	28	Colborne Street West / Oak Street	7	0	1267	0.4	$41,017.51
24	31	Canada Court	6	0	1113	0.4	$35,235.54
25	20	Holbor Street / Orchard Avenue	6	0	1054	0.3	$52,014.07
26	27	Forbes Crescent	4	0	947	0.3	$50,184.28
27	15	Darling Street / Twelfth Avenue	4	0	941	0.3	$50,184.28
28	33	Alpha Crescent	5	0	927	0.3	$29,879.66
29	40	Downtown Charlotte Street	6	0	891	0.3	$90,027.83
30	25	Lynden Road / Roy Boulevard	3	0	782	0.2	$184,740.45
31	32	Colborne St / Clara Crescent	2	0	460	0.1	$21,784.18

3.11 POLE REPLACEMENT PROJECTS

BPI conducts the replacement of poles under a separate budgeting program from other Capital Projects. Therefore, pole replacement projects are determined using a separate process from other asset classes. Geographical location is not taken into consideration to determine pole replacement projects. Poles are prioritized into a replacement order based on Risk Levels and those values used to determine Risk Levels in the following order:

1) Risk Level; 2) PoF; 3) CoF; 4) ESL%

Poles are selected in order from the prioritized list to meet the capital allowance of BPI's pole replacement program. A pole replacement plan has been developed to cover a 5 year period as shown in Table 23 below:

Table 15: Pole Replacement Projects

Year	Criteria	Number	Total Risk	Cost
1	Very High Priority, PoF = 4 & Very High Priority, PoF = 3, ESL% >80%	36	8688	$ 180,000.00
2	Remaining Very High Priority, PoF = 3	39	9090	$ 195,000.00
3	High Priority, PoF = 4, ESL% > 127% or Unknown	31	3847	$ 155,000.00
4	Some High Priority, PoF = 4, ESL% > 125%	37	4590	$ 185,000.00
5	Remaining High Priority, PoF = 4, ESL% > 125%	39	4728	$ 195,000.00
Total		**167**	**28388**	**$ 910,000.00**

Appendix K provides the pole ID numbers of the pole included in each project.

This pole replacement plan is to be reviewed yearly and adjusted to account for updated condition inspection information.

3.12 ONGOING AMP IMPROVEMENT PROGRAM

3.12.1PROJECT SCOPE

At this time the scope of BPI's Asset Management Plan is limited to 6 asset classes: Poles, Structures, Switches, Transformers, Primary Cables and Conductors, and Secondary Cables and Conductors. As BPI's business and data management practices and procedures improve it is possible to increase this scope to include such assets as Conductor Nodes, Elbows, Fuses, vehicles and Information technology assets. The scope of the AMP is currently sufficient to develop Capital Projects, and associated budgets.

3.12.2DATA GAPS

BPI's current asset database contains gaps in the recorded data required for the ODM to perform optimally. Logical assumptions have been made to fill these gaps, as described in Section *3.6*. While the current data is sufficient, improved data collection and data maintenance procedures would further improve the accuracy of the ODM.

Currently BPI's Asset Database does not consistently maintain records relating to the date of installation for all assets. As BPI's Asset Database improves, as per the recommendations of this report, ERL values can be calculated for all assets which will improve the results of the ODM, and the capital project selection process.

Ideally, the failure of specific assets could be tied directly to risk events that are used to capture the KPIs so that where applicable, predictions could be made when developing work projects as to what degree the KPIs would positively be affected per project. BPI's current data management procedures do not allow for this connection. An improved IT and data collection strategy will be able to link these factors and allow BPI to achieve a significant improvement in the output of the AMP.

3.12.3 LIFECYCLE MODELLING

Currently, the ODM uses a linear relationship between ERL% and PoF to model the lifecycle of assets (Figure 20).

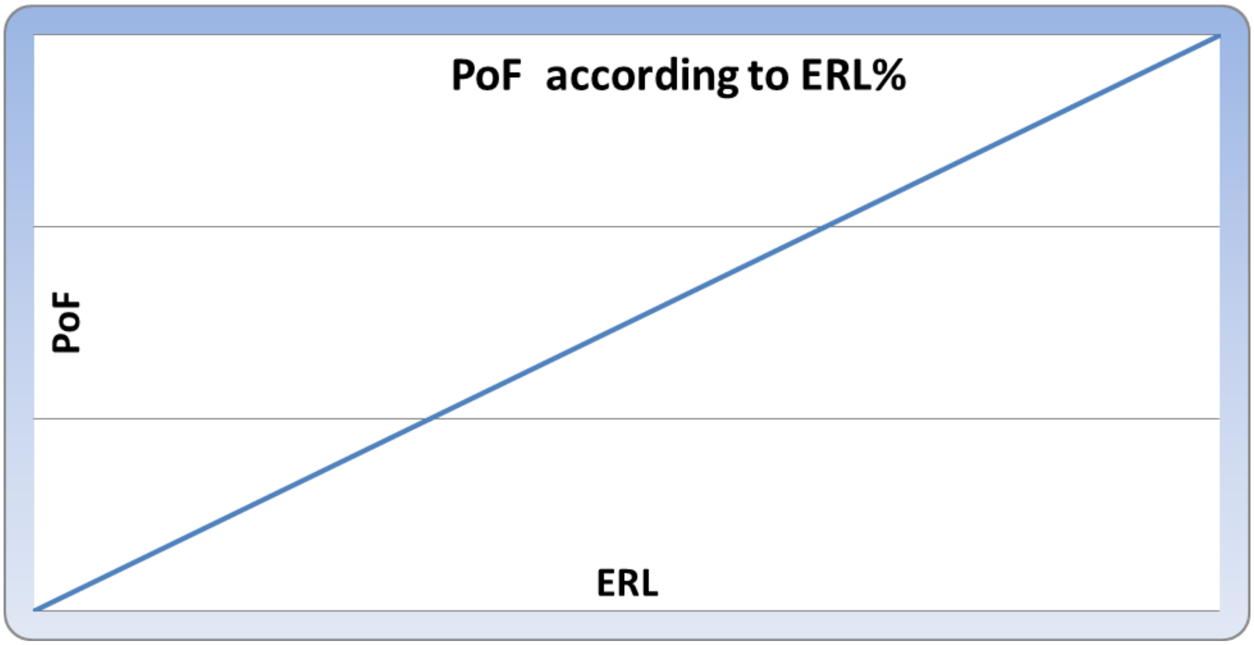


Figure 20: PoF According to ERL%

While straight line depreciation is adequate to predict the probable failure point of an asset, the development of lifecycles curves for all asset classes and subtypes would improve the accuracy of the ODM providing a much more accurate Technical Level of Service with which to relate PoF to the age of the asset. Figure 21 depicts an example of a lifecycle curve.

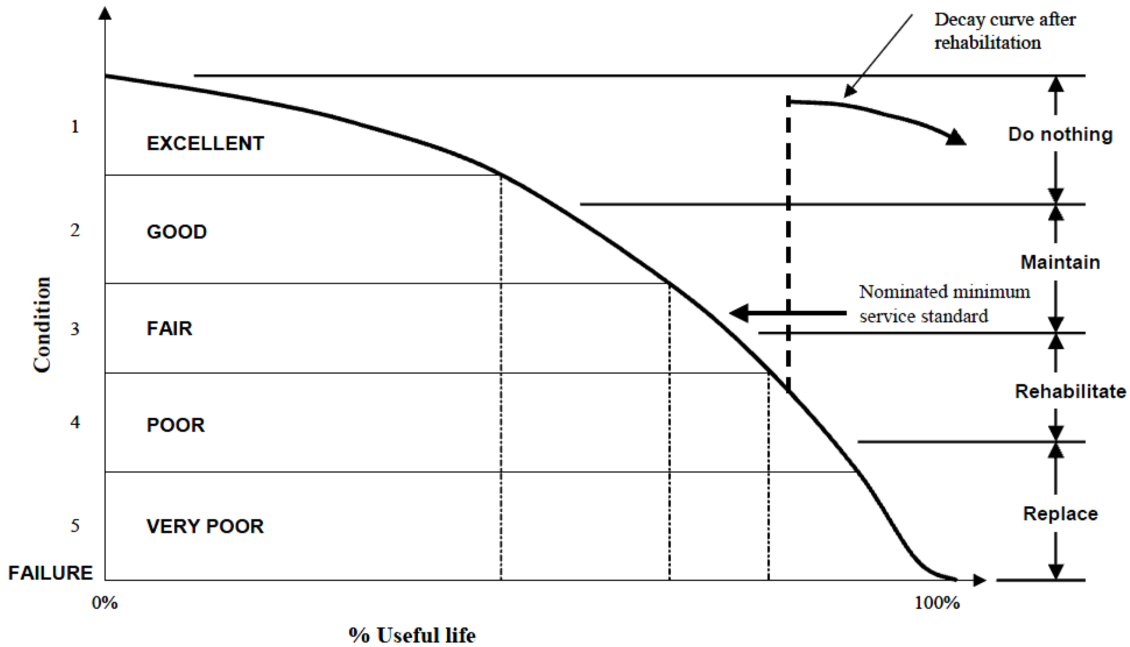


Figure 21: Example of Lifecycle Curve

This improved accuracy would allow the identification of more accurate Technical Level of Service for each asset class, providing the optimal timing for rehabilitation or replacement.

In order for these curves to be developed the Year of Installation and historical Condition Health Indices must be available in the Asset Database for all assets and the Estimated Service Life must be known for all asset types. ESL values have been determined for all asset classes included in the AMPr. As data is recorded over time, asset deterioration curves can be developed which will further enhance the output of the ODM. In the absence of the data required to produce these curves, a linear relationship is being used between asset condition and age.

3.12.4Critical Factor Scoring

BPI has developed and weighted critical factors for all asset classes. At this time the necessary connections between the critical scores and available data have not been made for all asset classes. Transformers and poles both have the required associated data with which to determine asset level scores for their critical factors. Transformers, which are able to be linked through both electrical connectivity and geographical location to all other asset classes, are leveraged to apply CoF values to all assets missing these values. While the logical application of the CoF scores in this way is sound, the accuracy of the ODM will be improved once the connection between data and critical scores for all asset classes is fully established.

3.13 Condition Assessment & Inspection Program

BPI is developing a GIS enabled mobile solution for condition assessments to be used during the three year condition assessment and inspection cycle. The implementation of the mobile solution will further ensure data integrity and allow direct input by inspectors into the asset database and allow for the implementation of detailed condition assessments using the evaluation of asset components and condition criteria by in-house inspectors.

3.13.1 Business Processes

BPI's current asset management business processes have been review by UEM. BPI's current asset management business processes, as used by the AMPr currently, are shown in Figure 22 below.

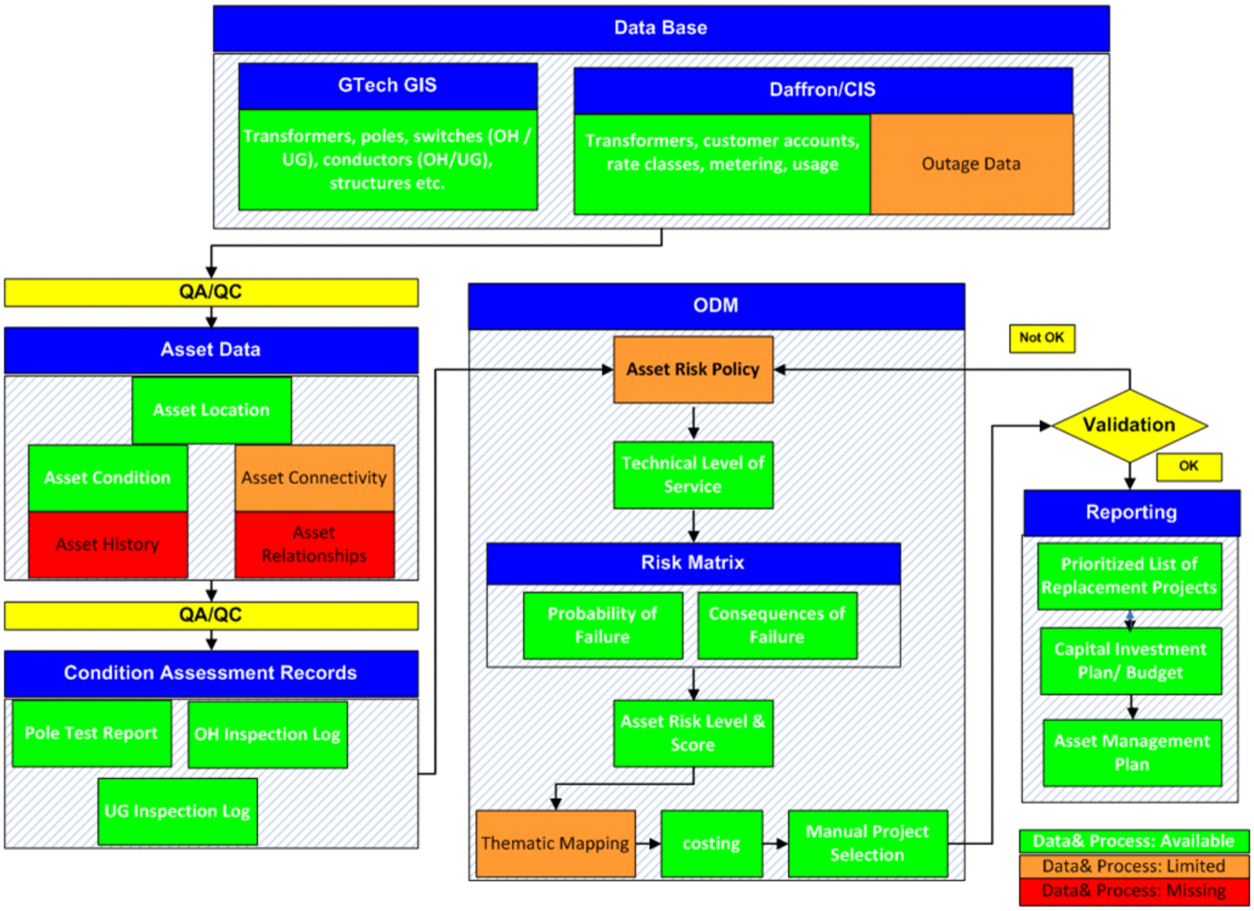


Figure 22: Current Asset Management Business Process

The current asset management processes contain some limited or missing data and processes. In addition, data must be reviewed and links between data must be recreated whenever data is updated.

4.0 OBSERVATIONS

Substantial improvement towards the implementation of Asset Management practices has occurred at BPI during the course of the project. As the data quality improves, including improved condition assessments and CHI updates occur, the quality and value of the asset Management processes will improve.

The current knowledge base concerning the lifecycle of the assets owned by most Local Distribution Companies is lacking when compared to the knowledge base found in many other municipal utilities. There has not been sufficient academic research, nor has sufficient detailed information been collected in the field, to create accurate asset deterioration probability curves. This lack of knowledge will improve over time, and BPI's investment in the AMPr developed during this project will be a great contribution to the industry as a whole.

5.0 CONCLUSION

BPI has implemented an Asset Management Program which assesses infrastructure assets based on condition assessments, lifecycles, LoS requirements, and Risk Analysis. The Asset Management Program is expected to achieve an improved performance of the distribution system and reduce the number of outages caused by asset failure. The Asset Management Program uses a methodology which provides:

- A structured Capital Project Prioritization Methodology which is directly related to asset condition assessments and the Corporate Risk Policy.
- A formalized risk model based on the Corporate Risk policy which includes a focus on health and safety, operational, environmental, external demand, financial, and political and regulatory risk; resulting in the program achieving direct benefits to the corporations overall goal of improving customer service.
- A proactive approach to asset management which uses Probability of Failure to identify potential asset failures, allowing appropriate actions to be taken to mitigate risk before it occurs.
- A risk centric approach to asset management which uses Consequence of Failure to identify the assets which pose the greatest risk to the organization, the customers, and the community so that mitigation activities can be applied in a prioritized manner.

The heart of BPI's Asset Management Program is UEM's Optimized Decision Model. The ODM applies the Asset Management strategies to BPI's asset data. The outputs of the ODM are used to develop and prioritize Capital Projects which address those assets that pose the greatest risk and identify assets that require risk mitigation measures to be in place.

The Asset Management Program is being improved yearly through improved data collection, data confidence, data architecture, business processes, and Asset Management procedures. Brantford Power is committed to a comprehensive Asset Management Program that can be used to provide appropriate information to the Board of Directors for capital planning decision making during the annual budget process.

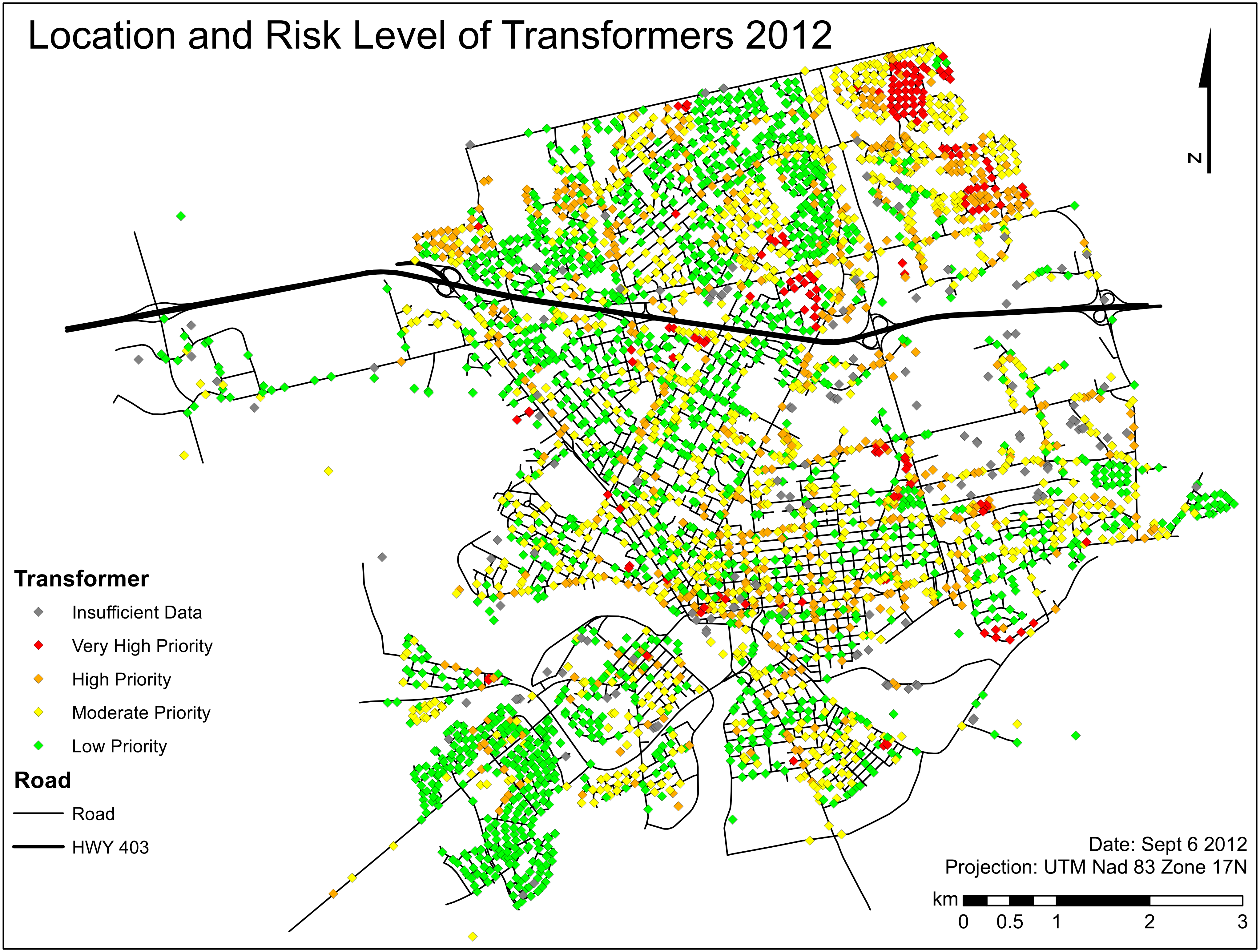
APPENDIX A

S2A DIAGRAM

Brantford Power - S2A Diagram										
Program Descriptions		**Strategic Service Parameters**				**Asset Association**				**Useful Life**
Program	**Service Name**	**Strategic Service Objective**	**Service Output**	**Customer Level of Service**	**Service Improvement Objective**	**Category**	**Asset Class**	**Location**	**Assets**	**Technical Level of Service (TLOS) at 90% of Useful Life**
Electricity	Electrical Distribution	To provide the customers of Brantford with safe, reliable electrical supply at a practical cost. To connect new customers To invest in green energy products ie. smart grid / automatic switching	kw/h	Efficient, effective and Reliable electrical service at the lowest practical cost.	Enhance protection to the electrical distribution systems Reduce number of service failures Improve mitigation and management of failure events Reduce electrical failure complaints and increase consumer confidence Increase system security Improve automation and information management for more reliable control and improved reporting requirements to reduce risk and increase efficiencies. replace equipment which is approaching the end of its useful life. Use innovative solutions Be proactive with changes in the regulation and community ie. plug in for electric cars	Supply	Transformer Station	TRANSFORMER AND MUNICIPAL STATIONS (TS & MS)	Rigid Busbars	55
									Station DC System	20
									Station Switch	50
									Steel Structure	50
									Power Transformers	45
									Station Service Transformers	45
									Station Independent Breakers	45
									Digital & Numeric Relays	20
									Reclosers	40
						Distribution	Aerial Conductors	OVERHEAD LINES (OH)	OH Conductors	60
							Cables	UNDERGROUND SYSTEMS (UG)	Primary Non-Tree Retardant Cross Linked Polyethylene Cables - Direct Buried	25
									Primary Non-Tree Retardant Cross Linked Polyethylene Cables - In Duct	25
									Primary Tree Retardant Cross Linked Polyethylene Cables - Direct Buried	30
									Primary Tree Retardant Cross Linked Polyethylene Cables - In Duct	40
									Secondary Cables - Direct Buried	35
									Secondary Cables - In Duct	40
									Primary Paper Insulated Lead Covered (PILC) Cables	65
							Connectors	MONITORING AND CONTROL SYSTEMS (Smart Grid Systems)	Remote SCADA	20
							Poles	OVERHEAD LINES (OH)	Fully Dressed Wood Poles	45
									Fully Dressed Concrete Poles	60
							Switches	OVERHEAD LINES (OH)	OH Line Switch - 3-phase gang operated, Switch blade	45
									Reclosers	40
									OH Line Switch Motor	25
									OH Line Switch RTU	20
									OH Integral Switches	45
								UNDERGROUND SYSTEMS (UG)	Underground Vault Switches (Submersible switch)	35
									Pad-Mounted Switchgear (Pad-mounted Switchgear)	30
							Structures	UNDERGROUND SYSTEMS (UG)	Underground Foundations (Pads)	55
									Underground Vaults (Vaults for Submersibles)	60
									Cable Chambers (Junction Boxes)	60
									Ducts (Direct buried ducts)	50
									Concrete Encased Duct Banks (Concrete incased ducts	55
							Transformers	OVERHEAD LINES (OH)	OH Transformers	40
								UNDERGROUND SYSTEMS (UG)	Submersible and Vault Transformers	35
									Pad Mounted Transformers	35
							Arresters	OVERHEAD LINES (OH)	Lightning Arresters	Future
								UNDERGROUND SYSTEMS (UG)	Elbow Arresters	Future
									Parking Stand Arresters	Future

APPENDIX B

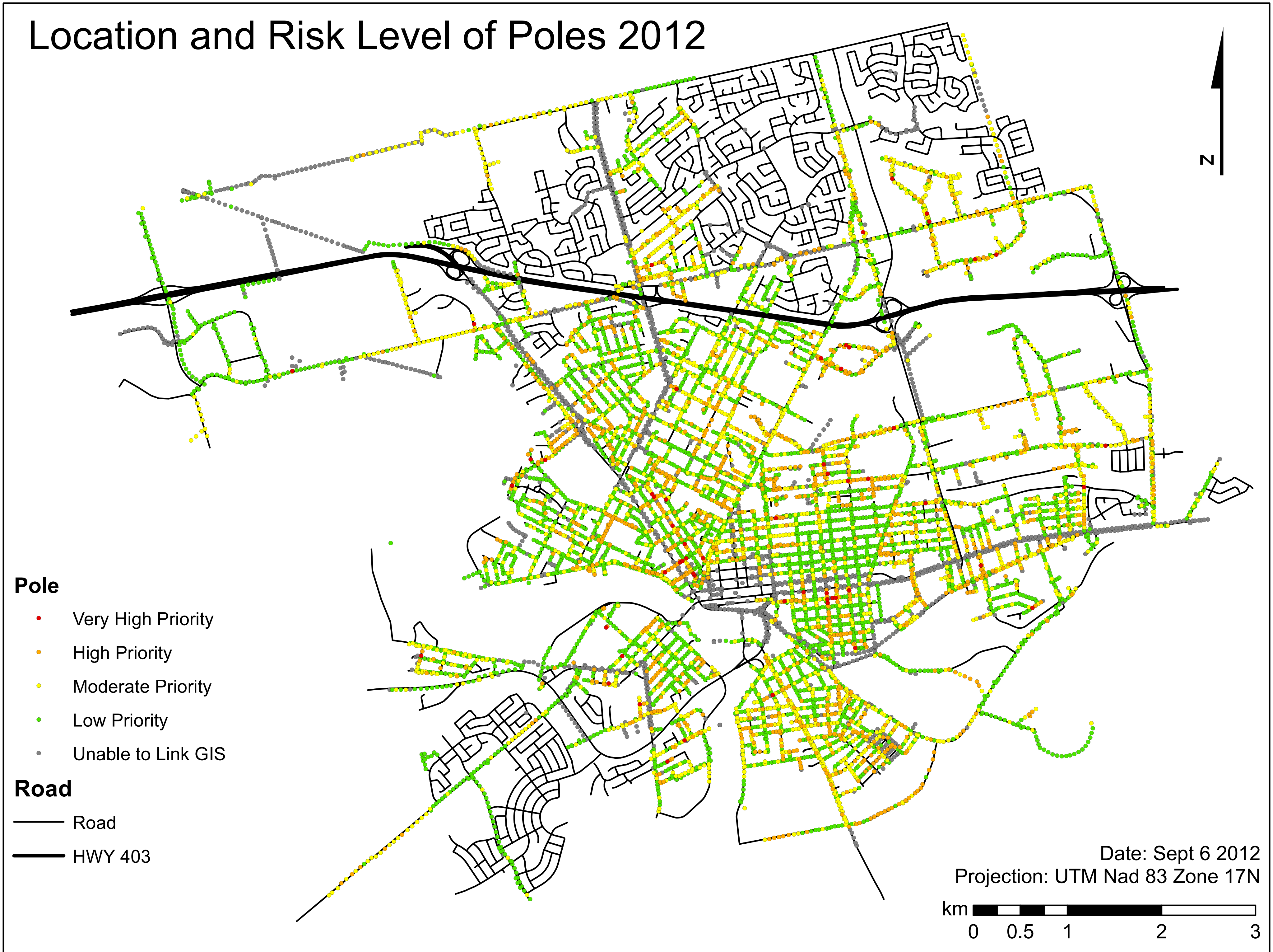
MAP OF TRANSFORMERS


Location and Risk Level of Transformers 2012
N
Transformer
Insufficient Data
Very High Priority
High Priority
Moderate Priority
Low Priority
Road
Road
HWY 403
Date: Sept 6 2012
Projection: UTM Nad 83 Zone 17N
km
0
0.5
1
2
3

APPENDIX C

MAP OF POLES

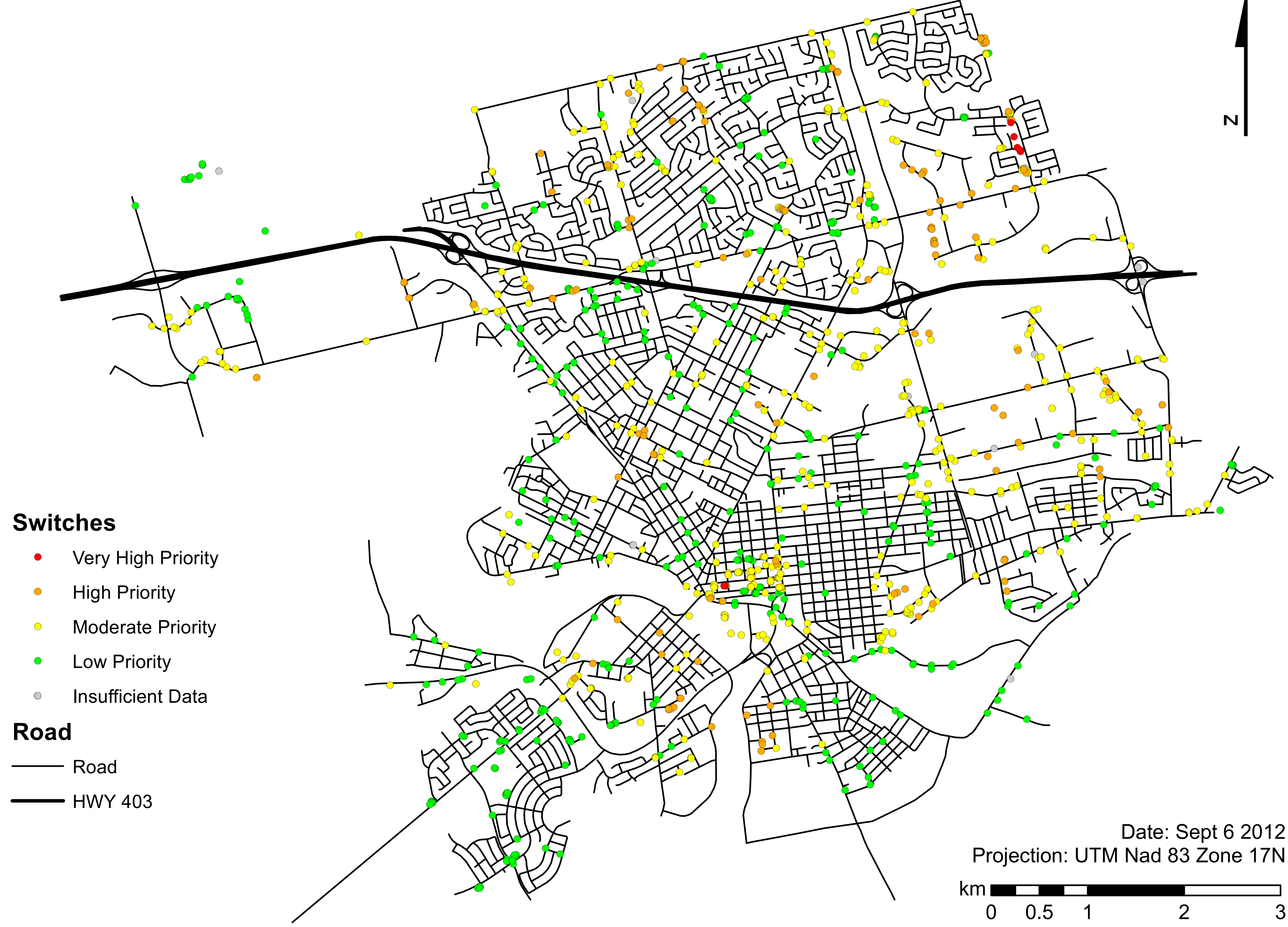
Location and Risk Level of Poles 2012



APPENDIX D

MAP OF SWITCHES

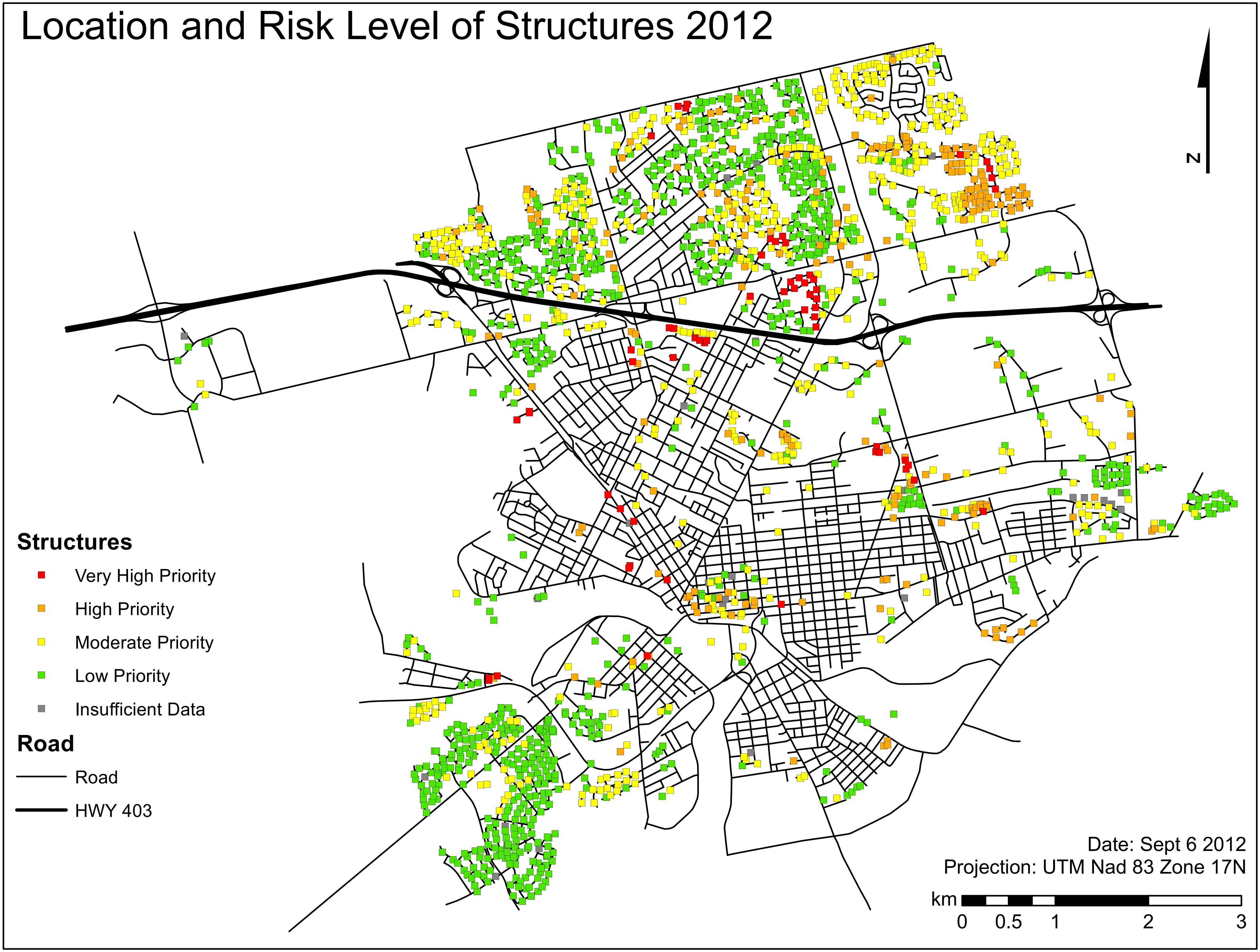
Location and Risk Level of Switches 2012



APPENDIX E

MAP OF STRUCTURES

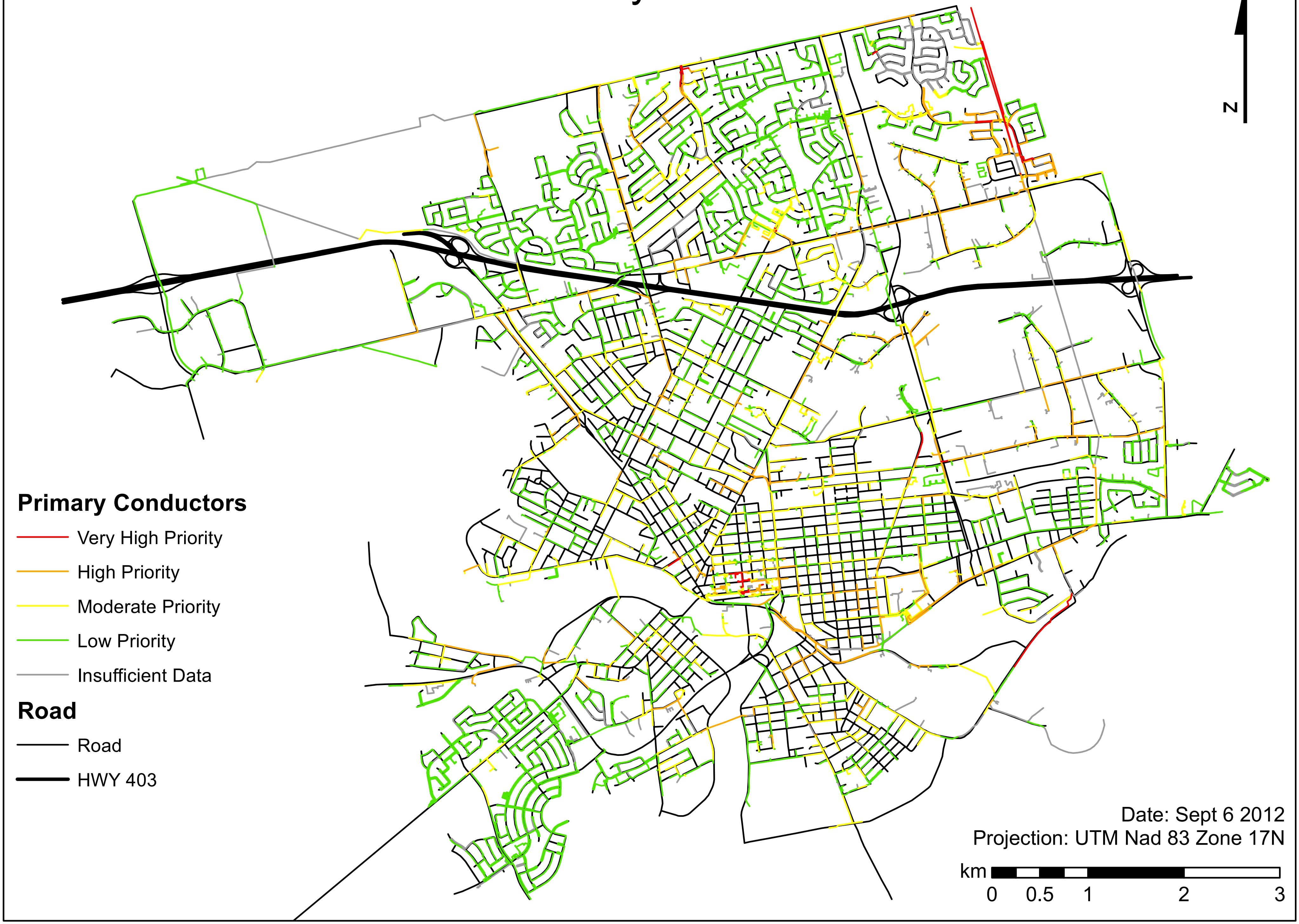
Location and Risk Level of Structures 2012



APPENDIX F

MAP OF PRIMARY CONDUCTORS

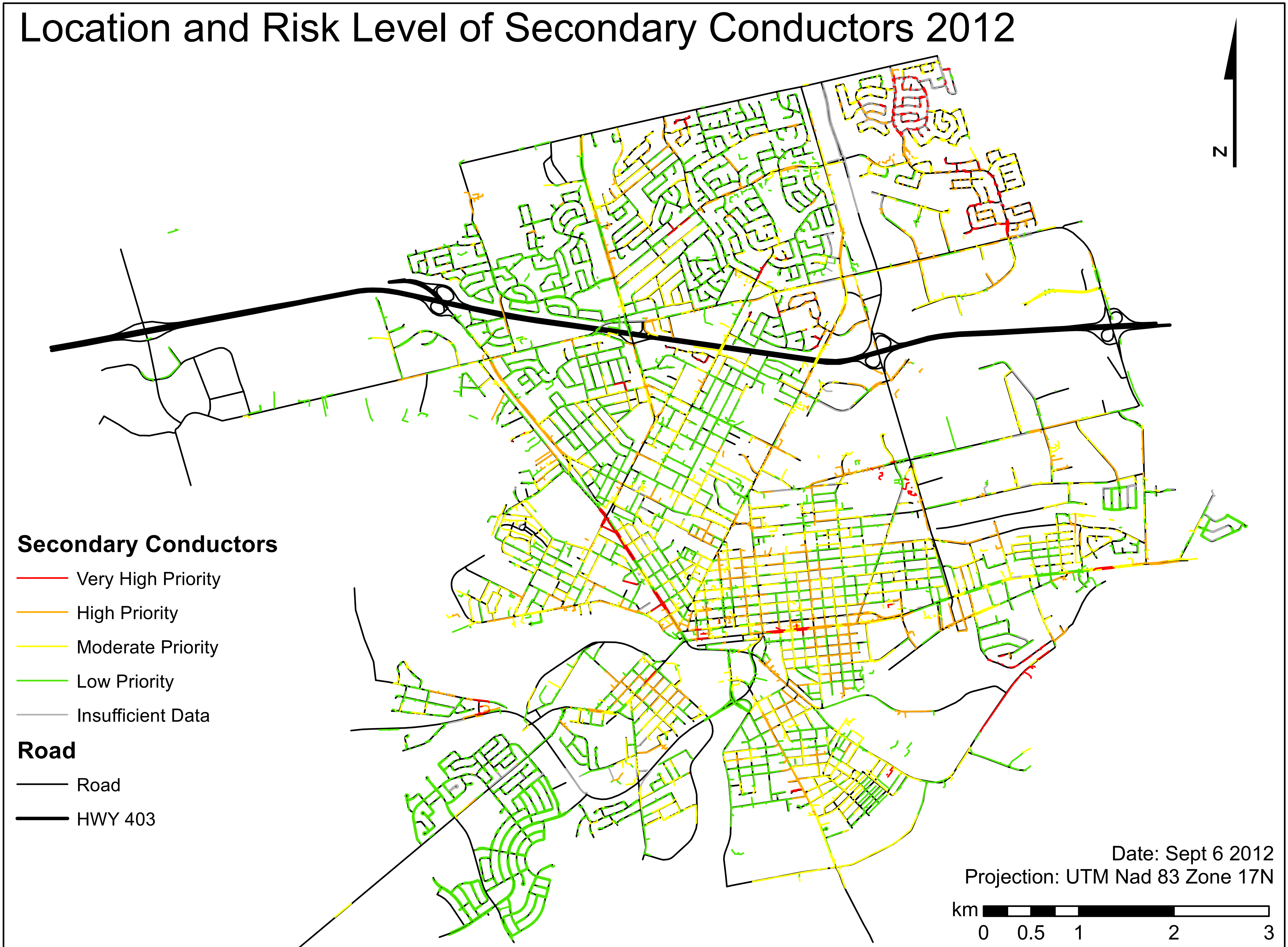
Location and Risk Level of Primary Conductors 2012



APPENDIX G

MAP OF SECONDARY CONDUCTORS

Location and Risk Level of Secondary Conductors 2012



APPENDIX H

CRITICAL FACTORS

#	Asset Classes & Associated Critical Factors:	Health & Safety (0 - 4)	External Demand (0 - 4)	Opera-tional (0 - 4)	Enviro-nmental (0 - 4)	Financial (0 - 4)	Political & Regulatory (0 - 4)	Critical Factor Weight (0- 24)	Critical Factor Probability (0- 4)	Critical Factor Rating (0- 96)
1	**Arial Conductors**							**6.8**	**3.3**	**22.0**
1.1	Short circuit due to tree overgrowth and branch interference		**1**	**3**		**1**		**5**	**4**	**20**
1.2	Conductor burnout due to overheating from load exceeding thermal capacity	**2**	**1**	**3**		**1**		**7**	**3**	**21**
1.3	Breakage due to excessive tension from heavy wind/ice storms	**3**	**2**	**3**		**3**		**11**	**2**	**22**
1.4	Breakage due to insulator or sleeve failure	**1**	**1**	**2**		**1**		**5**	**4**	**20**
1.5	Contacts with high boom/ladder from construction vehicles	**4**	**3**	**2**		**1**		**10**	**4**	**40**
1.6	Breakage due to corona cutting	**1**		**1**		**1**		**3**	**3**	**9**
2.1	Contacts during excavation	**4**	**1**	**2**		**1**	**3**	**11**	**4**	**44**
2.2	Insulation breakdown due to UV exposure	**1**		**2**		**1**		**4**	**3**	**12**
2.3	Insulation breakdown due to connector failure	**0**		**2**		**1**		**3**	**4**	**12**
2.4	Insulation breakdown due to water penetration at terminations in submersible installations	**1**		**3**		**1**		**5**	**3**	**15**
2.5	Corrosion of shield/concentric neutral wires at cable terminations			**2**		**2**		**4**	**2**	**8**

#	Asset Classes & Associated Critical Factors:	Health & Safety (0 - 4)	External Demand (0 - 4)	Opera-tional (0 - 4)	Enviro-nmental (0 - 4)	Financial (0 - 4)	Political & Regulatory (0 - 4)	Critical Factor Weight (0- 24)	Critical Factor Probability (0- 4)	Critical Factor Rating (0- 96)
2.6	Animal intrusion at cable openings in ducts and chewing insulation			**1**		**1**		**2**	**3**	**6**
2.7	Overheating / burnout due to excessive loading from illegal grow-ops			**1**		**1**		**2**	**3**	**6**
2.8	Insulation breakage due to age (30+ years)		**1**	**4**		**3**		**8**	**3**	**24**
3	**Poles**							**4.8**	**2.4**	**14.1**
3.1	Ground wire theft	**3**		**2**		**2**		**7**	**4**	**28**
3.2	Carpenter ants infestation	**1**		**1**		**1**		**3**	**4**	**12**
3.3	Under-cut due to excavation	**3**	**1**	**2**		**1**	**2**	**9**	**4**	**36**
3.4	Weak wood pole due to rot	**2**		**2**		**2**		**6**	**4**	**24**
3.5	Vehicle hits	**4**		**3**		**2**		**9**	**2**	**18**
3.6	Loose guy wires and/or missing wire covers	**3**						**3**	**1**	**3**
3.7	Damage by the public (weed eaters, sign postings etc.)	**1**		**1**				**2**	**1**	**2**
3.8	Wood-pecker damage			**1**				**1**	**1**	**1**

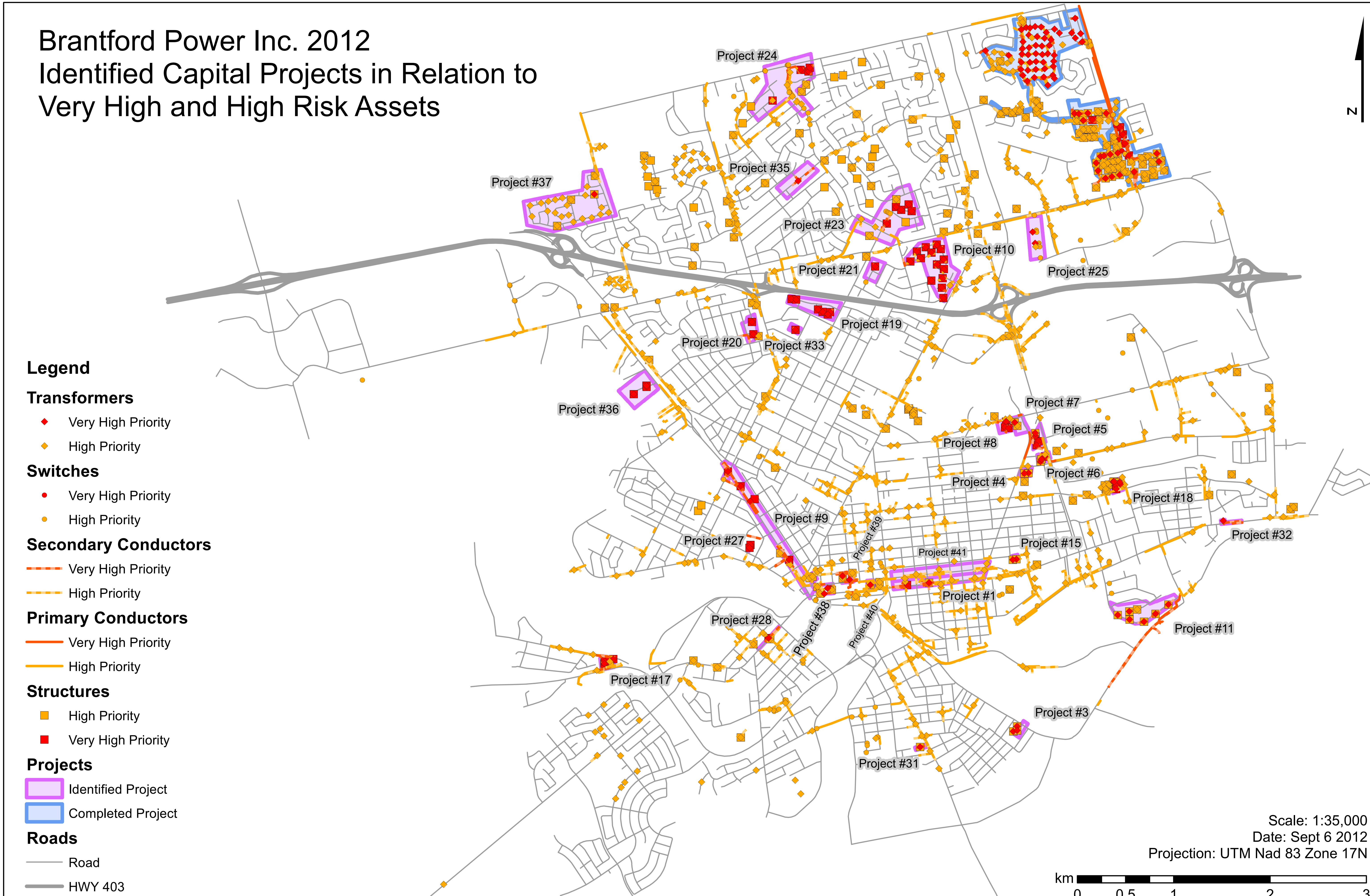
#	Asset Classes & Associated Critical Factors:	Health & Safety (0 - 4)	External Demand (0 - 4)	Opera-tional (0 - 4)	Enviro-nmental (0 - 4)	Financial (0 - 4)	Political & Regulatory (0 - 4)	Critical Factor Weight (0- 24)	Critical Factor Probability (0- 4)	Critical Factor Rating (0- 96)
3.9	Damage due to flood waters on butt treated poles			**2**		**1**		**3**	**1**	**3**
3.10	Transformer Mounted	**3**		**3**		**3**		**9**	**4**	**36**
4	**Switches**							**5.1**	**3.3**	**17.9**
4.1	Short circuit or insulation damage from water penetration			**2**		**2**		**4**	**4**	**16**
4.2	Spark-over due to loose contacts			**2**		**2**		**4**	**3**	**12**
4.3	Contacts burnout due to number of excessive operations			**2**		**2**		**4**	**3**	**12**
4.4	Damage due to water ingress from flash flooding	**1**		**2**		**1**		**4**	**2**	**8**
4.5	Damage due to animal contacts			**2**		**1**		**3**	**3**	**9**
4.6	Damage from const. vehicle, public vehicles	**3**		**3**		**3**		**9**	**4**	**36**
4.7	Damage due to closing on to a fault	**2**	**2**	**2**		**1**	**1**	**8**	**4**	**32**
5	**Transformers**							**8.7**	**2.7**	**24.7**
5.1	Rusting due to road salt	**2**		**3**	**2**	**3**		**10**	**2**	**20**

#	Asset Classes & Associated Critical Factors:	Health & Safety (0 - 4)	External Demand (0 - 4)	Opera-tional (0 - 4)	Enviro-nmental (0 - 4)	Financial (0 - 4)	Political & Regulatory (0 - 4)	Critical Factor Weight (0- 24)	Critical Factor Probability (0- 4)	Critical Factor Rating (0- 96)
5.2	Damage from const. vehicle, public vehicles	**3**		**3**	**2**	**3**		**11**	**4**	**44**
5.3	Short circuit or insulation damage from water penetration			**2**	**2**	**2**		**6**	**4**	**24**
5.4	Electric shock to public due to contact with sub-mersible transformer	**2**	**2**	**3**	**4**	**2**	**2**	**15**	**4**	**60**
5.5	Short circuit due to vegetation overgrowth	**1**		**2**		**1**		**4**	**2**	**8**
5.6	Damage / burnout due to overheating			**1**		**3**		**4**	**2**	**8**
5.7	Damage to bushing/spades due to excessive cable downward loading			**2**		**3**		**5**	**2**	**10**
5.8	Damage to 4kV transformers due to failure of old customer owned cables		**3**	**4**		**4**		**11**	**3**	**33**
5.9	Failure of old Station type transformers at customer locations due to age	**3**	**3**	**3**		**4**		**13**	**3**	**39**
5.10	Damage due to water from flash flooding	**1**		**3**		**1**		**5**	**2**	**10**
5.11	Obsolescence	**1**	**3**	**4**		**4**		**12**	**2**	**24**
5.12	Insulation failure/breakdown	**2**		**3**		**3**		**8**	**2**	**16**
5.13	Critical Customers	**4**	**4**	**4**	**4**	**4**	**4**	**24**	**4**	**96**

#	Asset Classes & Associated Critical Factors:	Health & Safety (0 - 4)	External Demand (0 - 4)	Opera-tional (0 - 4)	Enviro-nmental (0 - 4)	Financial (0 - 4)	Political & Regulatory (0 - 4)	Critical Factor Weight (0- 24)	Critical Factor Probability (0- 4)	Critical Factor Rating (0- 96)
6	**Structures**							**5.7**	**2.7**	**16.7**
6.1	Contacts during excavation	**1**		**2**		**3**	**2**	**8**	**4**	**32**
6.2	Damage due to water from flash flooding	**1**		**2**				**3**	**2**	**6**
6.3	Damage to cable risers from vehicle hits	**3**		**3**				**6**	**2**	**12**

APPENDIX I

MAP OF PROJECT LOCATIONS AND HIGH RISK ASSETS


Brantford Power Inc. 2012
Identified Capital Projects in Relation to
Very High and High Risk Assets
Legend
Transformers
Very High Priority
High Priority
Switches
Very High Priority
High Priority
Secondary Conductors
Very High Priority
High Priority
Primary Conductors
Very High Priority
High Priority
Structures
High Priority
Very High Priority
Projects
Identified Project
Completed Project
Roads
Road
HWY 403
Project #24
Project #35
Project #37
Project #23
Project #10
Project #21
Project #25
Project #19
Project #20
Project #33
Project #36
Project #7
Project #5
Project #8
Project #6
Project #4
Project #18
Project #9
Project #39
Project #27
Project #41
Project #15
Project #32
Project #1
Project #28
Project #38
Project #40
Project #11
Project #17
Project #3
Project #31
N
Scale: 1:35,000
Date: Sept 6 2012
Projection: UTM Nad 83 Zone 17N
km
0
0.5
1
2
3

APPENDIX J

ASSET COST RULE

Rationale

The cost rule base is developed based on the average installation cost of assets from BPI material database and work order cost history where available. For assets that did not have an applied cost available from these records, an estimated cost unit is assigned based on the cost of a comparable asset category in terms of labor, material and overheads. Labor and material costs are lumped together into a single cost unit with applicable overheads to avoid variability and for budgetary estimate purposes only. As some of the projects output by the AMPr have been undertaken during the start year and test year of the capital horizon, the cost rule base has therefore been validated through comparison of the calculated project costs to actual costs of one or more of the completed projects. Cost adjustments are then made to the rule base so that the projected budgeted costs are within a margin of error of 10% of the actual.

Cost Rule

Asset Type	Cost
Replacement cost of 1-ph pad-mount Tx. (50kVA – 167kVA)	$9,000.00
Replacement cost of 3-ph pad-mount Tx. (≤ 750kVA)	$26,000.00
Replacement cost of 3-ph pad-mount Tx. (1000kVA - 1500kVA)	$55,000.00
Replacement cost / meter, of 3-ph primary cable (1/0 XLPE)	$100.00
Replacement cost / meter, of 1-ph primary cable (1/0 XLPE)	$50.00
Replacement cost of 1-ph Submersible Tx. with Padmount	$15,000.00
Replacement cost of 3-ph Submersible Tx. with Padmount	$51,000.00
Replacement cost of Submersible Tx. with Submersible	$15,000.00
Replacement cost of Tx. / Switch vault	$9,000.00
Replacement cost of Submersible Tx. Vault	$30,000.00
Replacement cost of pole	$5,000.00
Re-stringing cost / meter of 1-ph primary OH wire	$30.00
Re-stringing cost / meter of 3-ph primary OH wire	$90.00
Replacement cost of 3-ph pad-mount switch	$55,000.00
Replacement cost of 1-ph pole-mount Tx.	$9,000.00
Replacement cost of 3-ph pole mount Tx.	$12,000.00
Replacement cost of 3-ph OH switch	$15,000.00
Replacement cost of a Recloser	$55,000.00
Replacement cost/meter of 3-ph primary cable	$100.00
Replacement cost/meter of 1-ph primary cable	$50.00
Replacement cost of 1-ph OH switch	$1,000.00
Replacement cost / meter, of UG secondary cable	$50.00
Replacement cost / meter, of OH secondary conductor	$30.00

APPENDIX K

POLES FOR REPLACEMENT

Pole ID's included in Pole Replacement Projects By Year

Year	**1**	**2**	**3**	**4**	**5**
Pole ID	01605	01035	09386	03296	05374
	07298	02890	02341	03423	05496
	07869	02891	02341-A	06692	06691
	00084	04725	03598	08164	06896
	00374	11427	05695	00003	06898
	01653	07435	03453	00579	06900
	02557	10393	03300	02384	07092
	04832	10666	05671	02470	07156
	07770	11624	05674	02503	07167
	1366-29	11641	05737	02550	07223
	1366-5	11641	08167	02596	07225
	10660	11669	10256	02607	07347
	08135	00371	03452	02699	07348
	04869	00372	03461	02700	07408
	04927	00375	08747-2	02701	07552
	10666	01797	02625	02703	07914
	14133	02191	02654	02704	08017
	02551	02546	02658	02705	08137
	02553	02860	02659	02706	08144
	02870	02905	02667	02709	08162
	05334	04686	02669	02739	08163
	08159	08341	03293	03297	08590
	09807	10371	03294	03298	08617
	02581	02481	03295	03313	08669
	03038	04732	00561	03364	08824
	07498	04837	05739	03366	08825
	11628	10425	06436	03424	08853
	06837	00412	08041	03482	09320
	10986	02490	08068	03484	09810
	07628	02591	08535	03485	10078
	03301	02592	08751	03560	10257
	06210	07687		03748	10258
	08202	08147		03759	11116
	02094	14402		03761	00704
	02087	02446		03895	03463
	02693-1	05095		05284	03771
		05583		05285	07705
		05584			08670
		1366-16			07107
Count	36	39	31	37	39
Cost	$180,000	$195,000	$155,000	$185,000	$195,000

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APPENDIX C

5 YEAR CAPITAL FORECAST

BRANTFORD POWER INC.
2013 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES

	2013 Budget	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
DISTRIBUTION PLANT - REGULAR OPERATIONS					
Transformer station equipment	$ -	$ -	$ 437,500	$ -	$ -
Overhead distribution system	1,173,000	1,658,900	1,878,096	1,421,550	1,039,632
Underground distribution system	891,100	1,867,905	1,557,700	2,833,586	1,562,164
Line transformers	502,000	706,350	895,818	997,458	955,331
Services	110,000	115,500	121,275	127,339	133,706
Meters	205,000	215,250	226,010	299,310	261,180
Electric plant held for future use	-	-	-	-	-
Work in progress	-	-	-	-	-
	2,881,100	4,563,905	5,116,399	5,679,243	3,952,013
Land and land rights	-	-	-	-	-
Buildings and fixtures	-	-	-	-	-
	2,881,100	4,563,905	5,116,399	5,679,243	3,952,013
CAPITAL CONTRIBUTIONS	(203,440)	(314,291)	(302,328)	(299,761)	(285,011)
GENERAL PLANT					
Computer software	310,000	600,000	550,000	550,000	530,000
Computer and office equipment	77,500	22,500	22,500	22,500	22,500
Vehicles	200,000	150,000	450,000	350,000	350,000
Tools, communication equipment and load control unit	25,000	25,000	25,000	25,000	25,000
System supervisory equipment (SCADA)	150,000	200,000	225,000	450,000	275,000
Other utility plant	-	-	-	-	-
	762,500	997,500	1,272,500	1,397,500	1,202,500
TOTAL CAPITAL EXPENDITURES	$ 3,440,160	$ 5,247,114	$ 6,086,571	$6,776,982	$4,869,502
SMART METERS					
Smart Metering (to/from regulatory liabilities)	-	-	-	-	-
Smart Metering - recoveries through rate riders	-	-	-	-	-
Amounts included in Regulatory Assets	-	-	-	-	-

BRANTFORD POWER INC.
2013 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES BY PROJECT

	2013 Budget	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
lew Lines and Equipment					
lew services (roll-ins)	$ 110,000	$ 115,500	$ 121,275	$ 127,339	$ 133,706
lew overhead line extensions	265,000	278,250	292,163	306,771	322,109
lew underground line extensions	280,000	294,000	308,700	324,135	340,342
lew overhead transformers	45,000	47,250	49,613	52,093	54,698
lew underground transformers	360,000	378,000	396,900	416,745	437,582
owerline feeder upgrades	450,000	360,000	378,000	396,900	-
lew subdivisions and townhomes costs	446,100	468,405	491,825	516,417	542,237
ity/MTO overhead relocation - general	50,000	52,500	55,125	57,881	60,775
ity/MTO overhead relocation - Shellard Lane	35,000	265,000	400,000		
ity/MTO overhead relocation - Colborne St.	15,000	8,000	100,000		
alhousie St downtown new build and relocates	-	25,000	25,000	1,500,000	
ak Park North Industrial servicing and line elocations	-	200,000	200,000	50,000	50,000
ther relocations and extensions	-				
cada and distribution automation	150,000	200,000	225,000	250,000	275,000
apacitor study and installation of line banks	120,000	70,000	75,000	80,000	85,000
tation cap banks at Powerline TS	-	-	437,500	-	-
owntown automation	-	-	-	200,000	-
	2,326,100	2,761,905	3,556,101	4,278,281	2,301,449
onversion - Ownership					
oles, towers and fixtures	10,000	10,000	10,000	30,000	30,000
verhead conductors and devices	10,000	10,000	10,000	25,000	25,000
nderground conduit	-	53,000	37,000	50,000	54,000
nderground conductors and devices	45,000	135,000	138,000	118,000	144,500
ine transformers	45,000	167,000	165,000	169,000	163,000
	110,000	375,000	360,000	392,000	416,500
ebuild of Existing Lines and Equipment					
oles, towers and fixtures	205,000	304,750	329,988	345,737	347,024
verhead conductors and devices	28,000	108,400	127,820	129,261	119,724
nderground conduit	35,000	626,000	186,050	149,153	179,310
nderground conductors and devices	70,000	258,500	271,125	175,881	301,775
ine transformers	52,000	114,100	284,305	359,620	300,051
	390,000	1,411,750	1,199,288	1,159,652	1,247,884

BRANTFORD POWER INC.
2013 BUDGET AND MULTI YEAR FORECAST
SCHEDULE OF CAPITAL EXPENDITURES BY PROJECT

	2013 Budget	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
etering					
etering (meters and instrument transformers	205,000	215,250	226,010	237,310	249,180
'holesale metering (IESO meter points)	-	-	-	62,000	12,000
ondo sub-metering	-	-	-	-	-
mart metering	-	-	-	-	-
	205,000	215,250	226,010	299,310	261,180
ther					
and and land rights	-	-	-	-	-
uilding	-	-	-	-	-
pgrade AM/FM & GIS system: asset management	150,000	100,000	50,000	50,000	30,000
ustomer Service phone system upgrades	160,000	-	-	-	-
ystems integration study	-	-	-	-	-
ystems installation (OMS, CIS, Fleet GPS, Barcode e	-	500,000	500,000	500,000	500,000
utage management system					
ffice furniture and computer hardware	77,500	22,500	22,500	22,500	22,500
ehicles	200,000	150,000	450,000	350,000	350,000
ools	25,000	25,000	25,000	25,000	25,000
lectric plant held for resale	-	-	-	-	-
'IP	-	-	-	-	-
	612,500	797,500	1,047,500	947,500	927,500
apital Budget - Gross	3,643,600	5,561,405	6,388,899	7,076,743	5,154,513
ontributions and Recoveries					
apital contributions	(203,440)	(314,291)	(302,328)	(299,761)	(285,011)
mart meter recoveries	-				
mart meter to reg asset recoveries	-				
APITAL BUDGET - NET	3,440,160	5,247,114	6,086,571	6,776,982	4,869,502

SERVICE QUALITY AND RELIABILITY PERFORMANCE

BPI tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding loss of supply related incidents.

BPI has elected to present its target indices for 2013 based on a 5 year average rather than a 3-year average of historical performance as stated in the Board's Filing Requirements for Electricity Transmission and Distribution Application dated June 28, 2012. Because 2011 and 2012 were anomalous years with winters warmer than usual and no major summer storms. BPI has determined that a 5 year average for its 2013 Test Year Targeted Indices will provides a more reasonable target. The following shows results for the past five years.

Table 2.19- Service Reliability Statistics

Year	2008	2009	2010	2011	2012	2013*	2013**
including Loss of Supply							
SAIDI	0.863	0.982	1.087	0.490	0.305	0.627	0.746
SAIFI	1.713	1.387	1.954	1.169	1.231	1.452	1.491
CAIDI	0.504	0.708	0.556	0.432	0.248	0.412	0.490
excluding Loss of Supply							
SAIDI	0.600	0.400	0.665	0.288	0.213	0.388	0.433
SAIFI	1.400	0.630	0.960	0.832	1.231	1.008	1.011
CAIDI	0.430	0.650	0.694	0.448	0.173	0.438	0.479
* 3 year average							
** 5 year average							

BPI is committed to the reliability of the distribution system and has set 2013 target indices for SAIDI and SAIFI as follows:

Table 2.20 – Target Indices for 2013

	Including Loss of Supply	*Excluding Loss of Supply*
SAIDI	0.75	0.43
SAIFI	1.49	1.01

In order to meet these targets BPI will need to continue to invest in capital and maintenance programs. In particular, the capital programs previously noted in Exhibit 2 with a primary driver of asset renewal are aimed at rebuilding infrastructure with a high probability of failure. Renewal of these assets removes the risk to reliability and safety that would otherwise be unacceptable.

In addition to the reliability indices, BPI also measures service quality indicators ("SQIs"). The table below summarizes BPI's reported SQIs for the historical years 2008 and 2009. In 2010, the SQI's were replaced by the Electricity Service Quality Requirements (ESQRs).

Table 2.21 - Reported Service Quality Indicators (SQIs)

Indicator	*OEB Minimum Standard*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*
Connection of New Services - Low Voltage	90% within 5 business days	100%	100%	100%	99%	99.6%	100%
Connection of New Services - High Voltage	90% within 10 business days	100%	N/A	100%	N/A	N/A	N/A
Appointment Scheduling	90% within 5 business days	N/A	100%	100%	100%	100%	100%
Appointment - Met	90% of the time	100%	100%	100%	100%	99.5%	100%
Rescheduling a missed appointment	100% of the time (90% of time until 2009)	N/A	98%	100%	89%	83%	100%
Telephone Accessiblity	65% of calls answered within 30 seconds	80%	76%	71%	72%	64.7%	65%
Telephone Call Abandon Rate	10% or less on a yearly basis	N/A	3%	4%	5%	5.9%	7%
Written Responses to Enquiries	80% within 10 business days	98%	100%	100%	100%	99.8%	100%
Emergency Response - Urban Areas	80% within 60 minutes	100%	100%	100%	100%	100%	100%
Emergency Response - Rural Areas	80% within 120 minutes	N/A	N/A	N/A	N/A	N/A	N/A
Reconnection Performance Standard	85% within 2 business days	N/A	N/A	N/A	99%	100%	99%

Explanation for SQI Under-Performance

BPI notes that 'Rescheduling a missed appointment' and 'Telephone response' SQIs were under the Board's minimum threshold in 2011 and 2012 respectively. BPI provides the following explanation for the results in question.

On May 10, 2012, Board Staff contacted BPI requesting an explanation as to why the 2011 SQI for 'Rescheduling a missed appointment' not been met. In response to the Board Staff inquiry, BPI looked into the matter further and advised that although it is BPI's standard operating procedure to complete service orders on the date scheduled and complete the documentation at the same time, BPI determined that the paper work was completed at a later date and the date recorded was the date on which the paper work was completed as opposed to the date on which the appointment was met. The date on which the appointment was met is considered the standard.

BPI's telephone response statistics in 2012 were 64.7%, which is very slightly under the Board's standard of 65%. As discussed in greater detail in Exhibit 4, Tab 2, the Customer Service function previously provided by the City for electricity, water and retail activities was split with the employees providing services for electricity billing, collection and customer care transferred to BPI on April 1, 2012. At the date of transfer, some of the customer service positions that were transferred were, in fact, vacant. The lower than typical telephone response metric in 2012 was the result of this significant transition.

ALLOWANCE FOR WORKING CAPITAL:

Overview and Calculation by Account:

BPI's working capital allowance is forecast to be $13,941,051 for 2013 based on the methodology outlined on page 17 of the Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012, namely, 13% of the sum of Cost of Power and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General), as illustrated on Table 2.22 below. BPI has provided a spreadsheet setting out BPI's Cost of Power calculations as Appendix D.

Table 2.22 - Working Capital Calculation

Description	2013 Test Year (CGAAP)
Distribution Expenses - Operation	1,576,506
Distribution Expenses - Maintenance	2,033,090
Billing and Collecting	2,863,215
Community Relations/3rd tranche CDM	232,777
Administrative and General Expenses	2,498,437
Taxes Other than Income Taxes	12,000
Total Operating Expenses for Working Capital Allowance	9,216,025
Cost of Power	98,022,828
Working Capital	107,238,853
Working Capital Allocance (13%)	13,941,051

COST OF POWER

BPI has calculated cost of power for the 2012 Bridge year and 2013 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3 below. The electricity prices used in the 2013 calculation were the published prices in the Board's Regulated Price Plan Price

Report – May 1, 2013 to April 30, 2014, issued April 5, 2013. BPI will update the electricity prices should the Board publish a revised Regulated Price Plan Report prior to a Decision.

The cost of power calculations and summaries for the 2012 Bridge Year and 2013 Test Year is provided in Appendix D.

APPENDIX D

COST OF POWER CALCULATION

2012 Cost of Power Calculation

2012 Load Foreacst	kWh	kW	2011 %RPP
Residential	284,844,991		87%
General Service < 50 kW	99,625,182		90%
General Service 50 to 4,999 kW	537,717,579	1,386,954	26%
Street Lighting	7,395,384	22,533	0%
Sentinel Lighting	435,374	1,331	0%
Unmetered Scattered Load	1,535,988		0%
Hydro One			0%
TOTAL	**931,554,498**	**1,410,819**	

Electricity - Commodity RPP	2012	2012 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2012**	
Residential	247,815,142	1.0420	258,223,378	$0.08069	$20,836,044
General Service < 50 kW	89,662,664	1.0420	93,428,496	$0.08069	$7,538,745
General Service 50 to 4,999 kW	139,806,571	1.0420	145,678,447	$0.08069	$11,754,794
Street Lighting	0	1.0420	0	$0.08069	$0
Sentinel Lighting	0	1.0420	0	$0.08069	$0
Unmetered Scattered Load	0	1.0420	0	$0.08069	$0
Hydro One	0	1.0420	0	$0.08069	$0
TOTAL	**477,284,377**		**497,330,320**		**$40,129,584**

Electricity - Commodity Non-RPP	2012	2012 Loss			
Class per Load Forecast	**Forecasted**	**Factor**		**2012**	
Residential	37,029,849	1.0420	38,585,102	$0.07877	$3,039,349
General Service < 50 kW	9,962,518	1.0420	10,380,944	$0.07877	$817,707
General Service 50 to 4,999 kW	397,911,008	1.0420	414,623,271	$0.07877	$32,659,875
Street Lighting	7,395,384	1.0420	7,705,990	$0.07877	$607,001
Sentinel Lighting	435,374	1.0420	453,660	$0.07877	$35,735
Unmetered Scattered Load	1,535,988	1.0420	1,600,499	$0.07877	$126,071
Hydro One	0	1.0420	0	$0.07877	$0
TOTAL	**454,270,121**		**473,349,467**		**$37,285,737**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	296,808,481	$0.0080	$2,374,468
General Service < 50 kW		kW	103,809,440	$0.0072	$747,428
General Service 50 to 4,999 kW		kW	1,386,954	$2.4601	$3,412,046
Street Lighting		kWh	22,533	$2.2708	$51,168
Sentinel Lighting		kW	1,331	$2.2973	$3,059
Unmetered Scattered Load		kW	1,600,499	$0.0072	$11,524
Hydro One		kWh	0	$2.4601	$0
TOTAL					**$6,599,692**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	296,808,481	$0.0055	$1,632,447
General Service < 50 kW		kW	103,809,440	$0.0048	$498,285
General Service 50 to 4,999 kW		kW	1,386,954	$1.6398	$2,274,328
Street Lighting		kWh	22,533	$1.5138	$34,110
Sentinel Lighting		kW	1,331	$1.5315	$2,039
Unmetered Scattered Load		kW	1,600,499	$0.0048	$7,682
Hydro One		kWh	0	$1.6398	$0
TOTAL					**$4,448,891**

Wholesale Market Service					
Class per Load Forecast				**2012**	
Residential			296,808,481	$0.0052	$1,543,404
General Service < 50 kW			103,809,440	$0.0052	$539,809
General Service 50 to 4,999 kW			560,301,717	$0.0052	$2,913,569
Street Lighting			7,705,990	$0.0052	$40,071
Sentinel Lighting			453,660	$0.0052	$2,359
Unmetered Scattered Load			1,600,499	$0.0052	$8,323
Hydro One			0	$0.0052	$0
TOTAL			**970,679,787**		**$5,047,535**

Rural Rate Assistance					
Class per Load Forecast				**2012**	
Residential			296,808,481	$0.0011	$326,489
General Service < 50 kW			103,809,440	$0.0011	$114,190
General Service 50 to 4,999 kW			560,301,717	$0.0011	$616,332
Street Lighting			7,705,990	$0.0011	$8,477
Sentinel Lighting			453,660	$0.0011	$499
Unmetered Scattered Load			1,600,499	$0.0011	$1,761
Hydro One			0	$0.0011	$0
TOTAL			**970,679,787**		**$1,067,748**

Cost of Power Calculation	2012
4705-Power Purchased	$77,415,321
4708-Charges-WMS	$5,047,535
4714-Charges-NW	$6,599,692
4716-Charges-CN	$4,448,891
4730-Rural Rate Assistance	$1,067,748
4750-Low Voltage	-
TOTAL	**94,579,187**

Cost of Power Calculation 2013

2013 Load Foreacst	kWh	kW	2011 %RPP		
Residential	280,913,502		87%		
General Service < 50 kW	97,535,297		90%		
General Service 50 to 4,999 kW	531,977,718	1,354,270	26%		
Street Lighting	7,553,004	23,455	0%		
Sentinel Lighting	443,490	1,356	0%		
Unmetered Scattered Load	1,454,727		0%		
Hydro One			0%		
TOTAL	**919,877,738**	**1,379,081**			

Electricity - Commodity RPP	2013				
Class per Load Forecast RPP	**Forecasted**	**2013 Loss Factor**		**2013**	
Residential	244,394,747	1.0349	252,924,732	$0.08395	$21,233,031
General Service < 50 kW	87,781,767	1.0349	90,845,569	$0.08395	$7,626,486
General Service 50 to 4,999 kW	138,314,207	1.0349	143,141,717	$0.08395	$12,016,747
Street Lighting	0	1.0349	0	$0.08395	$0
Sentinel Lighting	0	1.0349	0	$0.08395	$0
Unmetered Scattered Load	0	1.0349	0	$0.08395	$0
Hydro One	0	1.0349	0	$0.08395	$0
TOTAL	**470,490,721**		**486,912,018**		**$40,876,264**

Electricity - Commodity Non-RPP	2013				
Class per Load Forecast	**Forecasted**	**2013 Loss Factor**		**2013**	
Residential	36,518,755	1.0349	37,793,351	$0.08717	$3,294,446
General Service < 50 kW	9,753,530	1.0349	10,093,952	$0.08717	$879,890
General Service 50 to 4,999 kW	393,663,512	1.0349	407,403,348	$0.08717	$35,513,350
Street Lighting	7,553,004	1.0349	7,816,623	$0.08717	$681,375
Sentinel Lighting	443,490	1.0349	458,969	$0.08717	$40,008
Unmetered Scattered Load	1,454,727	1.0349	1,505,500	$0.08717	$131,234
Hydro One	0	1.0349	0	$0.08717	$0
TOTAL	**449,387,018**		**465,071,743**		**$40,540,304**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	290,718,083	$0.0084	$2,442,032
General Service < 50 kW		kWh	100,939,521	$0.0076	$767,140
General Service 50 to 4,999 kW		kW	1,354,270	$2.5958	$3,515,413
Street Lighting		kW	23,455	$2.3960	$56,199
Sentinel Lighting		kW	1,356	$2.4240	$3,287
Unmetered Scattered Load		kWh	1,505,500	$0.0076	$11,442
Hydro One		kWh	0	$2.5958	$0
TOTAL					**$6,795,513**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	290,718,083	$0.0057	$1,657,093
General Service < 50 kW		kWh	100,939,521	$0.0049	$494,604
General Service 50 to 4,999 kW		kW	1,354,270	$1.6850	$2,281,944
Street Lighting		kW	23,455	$1.5555	$36,485
Sentinel Lighting		kW	1,356	$1.5737	$2,134
Unmetered Scattered Load		kWh	1,505,500	$0.0049	$7,377
Hydro One		kWh	0	$1.6850	$0
TOTAL					**$4,479,637**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential			290,718,083	$0.0044	$1,279,160
General Service < 50 kW			100,939,521	$0.0044	$444,134
General Service 50 to 4,999 kW			550,545,065	$0.0044	$2,422,398
Street Lighting			7,816,623	$0.0044	$34,393
Sentinel Lighting			458,969	$0.0044	$2,019
Unmetered Scattered Load			1,505,500	$0.0044	$6,624
Hydro One			0	$0.0044	$0
TOTAL			**951,983,761**		**$4,188,729**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential			290,718,083	$0.0012	$348,862
General Service < 50 kW			100,939,521	$0.0012	$121,127
General Service 50 to 4,999 kW			550,545,065	$0.0012	$660,654
Street Lighting			7,816,623	$0.0012	$9,380
Sentinel Lighting			458,969	$0.0012	$551
Unmetered Scattered Load			1,505,500	$0.0012	$1,807
Hydro One			0	$0.0012	$0
TOTAL			**951,983,761**		**$1,142,381**

Cost of Power Calculation	2013
4705-Power Purchased	$81,416,568
4708-Charges-WMS	$4,188,729
4714-Charges-NW	$6,795,513
4716-Charges-CN	$4,479,637
4730-Rural Rate Assistance	$1,142,381
4750-Low Voltage	-
TOTAL	**98,022,827**

BASIC GREEN ENERGY PLAN INTRODUCTION

BPI's Basic Green Energy Plan ("the Plan") has been prepared in accordance with the requirements set out by the Board, which in turn support the Provincial Government's goals as expressed in the *Green Energy and Green Economy Act, 2009* (GEGEA). The Plan is intended to inform the Board and interested stakeholders about the readiness of BPI's distribution system for connecting renewable generation and to identify any expansion or reinforcement necessary to accommodate renewable generation.

BPI submitted a Basic Green Energy Plan to the OPA dated October, 2012 and has provided a copy in Appendix E. The OPA provided a Letter of Comment which has also been provided in Appendix F.

BPI will not be proposing any material investments in renewable infrastructure. However BPI expects a modest growth in renewable generation and minor system upgrades to accommodate renewable generation but does not seek to fund those expansions through this GEA Plan as they will be funded through regular distribution rates.

APPENDIX E

GREEN ENERGY PLAN

BASIC GREEN ENERGY PLAN

2012

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Contents

1.0 Introduction

Brantford Power Inc.'s ("BPI") Green Energy Plan ("the Plan") has been prepared in accordance with the requirements set out by the Ontario Energy Board ("the Board"), which in turn support the Provincial Government's goals as expressed in the Green Energy Green Economy Act (GEGEA). The Plan is intended to inform the Board and interested stakeholders about the readiness of BPI's distribution system for connecting renewable generation and to identify any expansion or reinforcement necessary to accommodate renewable generation.

2.0 Current Assessment of the Distribution System

BPI supplies electricity to its customers in the City of Brantford through three High-Voltage Transformer Stations (TS) via mainly overhead primary circuits at 27.6kV. Two of these, Brant TS and Brantford TS are owned by Hydro One Networks Inc. (HONI) whereas the third, Powerline Municipal Transformer Station (PMTS) is jointly owned by BPI with Brant County Power Inc. (BCPI).

Apart from supplying customers within its own territory, BPI also delivers to BCPI which is an embedded distributor to BPI. BCPI not only receives electricity from metered locations on three BPI distribution feeders but also has dedicated feeders from Brant TS and Powerline MTS passing through BPI service territory.

Table 1 sets BPI's share of distribution power from the three High-Voltage Transformer Stations.

Table 1: BPI Share of Power from Transformer Stations

TS	Total Number of Feeders at TS	Number of BPI Owned Feeders at TS	Thermal Capacity (MW)	Short Circuit Capacity (MVA)	BPI Share (%)
Brantford Y bus	5	5	35.9	62.35	100**
Brantford Z bus****	5	5	21.6	2.35	100
Brant	8	3	45.89	166.05	37.5
Powerline	8	5*	36.1	180.5	62.5***

*At present 2 of these feeders are not in service
** Brant County Power embedded on 64M25, and 64M27
*** Brant County Power embedded on PM1
**** Generation restriction

Note: Available power is based on one transformer nameplate rating and assuming that the second transformer is out of service. Brant TS capacity is based on the limits set by HONI. Powerline MTS capacity is based on BPI's share in ownership

2.1 BPI Standard for Allocating Capacity

2.1.1 Station Capacity

The next step is to determine the capacity availability at the TS to accommodate new generation. The two stations owned by HONI (Brant TS and Brantford TS) are subject to the capacity allocation model of the Transmitter.[1]

For Powerline MTS, which BPI jointly owns, BPI assesses that the maximum allowable capacity for generation is 50% of the nameplate capacity of one transformer for the entire TS. This standard takes into consideration, the possible reverse flow of 100% generation on the feeders under zero loading (assumed worst case scenario). This limit is set to allow for a safety margin due to the critical nature of this transformer asset.

Since BPI has a 5/8th share in the ownership of Powerline MTS, the same proportion of available capacity is assumed for BPI in terms of the transformer's rated capacity. This translates to 26 MVA of available generator capacity at the station for BPI.

2.1.2 Feeder Capacity

The first step in determining system capacity for new generation connections is based on available capacity on the primary distribution feeders. This in turn is based on BPI's standard conductor size for these feeders. If sections of the feeders have a smaller conductor size, they are identified and the feeder capacity is limited to the smaller sized conductor, until the time these can be upgraded to the standard size conductor. In these cases, there may be an impact to capital expenditures.

The standard conductor size for the main primary feeders consisting of a single three-phase circuit is 556 mcm Aluminum with an allowable current carrying capacity of 625A (approximately) under maximum thermal loading conditions. Each feeder is ideally loaded to approximately 50% of its thermal capacity which amounts to 15MVA on each feeder. This criterion is based on the contingency where load has to be transferred from one fully loaded feeder to another, allowing the feeder to take over 100% of the load of the transferred feeder without exceeding its thermal loading limit. The same criterion is applicable to allocate capacity for embedded renewable distribution resources. Assuming the worst case scenario with

[1] http://www.hydroone.com/Generators/Pages/AvailableCapacity.aspx

maximum generation and zero load on the feeders involved in the transfer, the total generation will be equal to the maximum thermal capacity of the feeder.

Based on the above criterion, the details on available capacity on each feeder are provided in Appendix A

2.1.3 Remaining System Capacity

The predominant source of potential renewable generation in Brantford is roof-mounted solar photovoltaic cells ("PV"). This assessment is supported by BPI's experience with the FIT and MicroFIT programs, and BPI's Rooftop Solar Capacity Study (Appendix B). Given the demographics of BPI's service area, all of BPI's customers have the ability to install generation projects. This makes it difficult to identify areas that will see an increase in renewable generation and to plan pro-actively to assess and/or upgrade the distribution system to accommodate them. However, based on the outcomes from the study evaluating potential for roof-mounted generation (Appendix B), the generated power at any location should generally be less than the load of the customer at that location. Taking these factors into consideration and subject to the constraints discussed below in section 2.3 and 2.4, the distribution system, as designed for the load customer, should be adequate to accept new renewable generation.

The above assessment is based on the feedback from suppliers of distribution transformers in BPI's system, that they are capable of reverse power flows equal to 100% of their rated name-plate capacities. This in turn allows BPI to accept renewable generation equal to the maximum thermal loading of the secondary conductors from these transformers to the customer location as well as the primary lateral circuit feeding the transformer from the main primary feeders.

2.2 Constraints in Connecting Renewable Generation

The following constraints can limit the number and capacity of renewable resources that can be connected to Brantford Power distribution system apart from the above standards:

2.2.1 Limitation of Transformer design at HONI Owned TSs

The power transformers at the Brantford TS are of a dual secondary winding design. HONI has communicated to LDCs, including BPI, that any reverse power flow through these transformers can potentially generate circulating currents and result in overheating and pre-mature catastrophic failures of these transformers.

Effective January 1, 2012, Hydro One's Brantford TS Z bus has been restricting new generators from connecting projects of any type or size. The connection of new generation would exceed the maximum three phase fault value as stated in the Transmission System Code, Appendix 2 - Transmission System Connection Point Performance Standards.

The planned replacement of the second CGE transformer at the Hydro One Brantford TS Y bus will limit the available short circuit capacity listed under section 2.0 and as a result will limit the amount of generation the Y bus can accept in the future. This is due to the fact that the replacement transformer has lower internal impedance and will produce more short circuit current than the existing transformer, thereby taking up more of its share of the available short circuit capacity at the bus. This replacement is currently scheduled for February, 2013.

At this time, no applications with approved Connection Impact Assessments have been denies, but BPI is no longer accepting new applications on this restricted Z-bus.

2.2.2 Limitation due to HONI Threshold Capacity Limits

Another potential constraint is the threshold capacity (50%) of the minimum load on any feeder, set by HONI, above which a remote transfer trip with the TS is required. A generator may be initially allowed to connect to a feeder if the generation is below this threshold limit, however, with the introduction of more generation with time and/or changes in the minimum load conditions on this feeder, all generators will be required to install or retrofit a transfer trip scheme with the TS to comply with HONI's requirement or remain off-line. This would be an additional cost burden on the generators.

2.3 Unique Challenges with Current Configuration

BPI's distribution system is designed primarily as a combination of radial and open-ended loop-feed system where, at any point in time, each primary feeder has a single source located at one of the three High-voltage Transformer Stations. All protection equipment on these feeders is coordinated with respect to this source. The main primary feeders are further sub-divided into single phase and three phase branch circuits. The service area of each feeder is separated from the other by several open point connections in the network through three-phase switches. These open points are configurable to allow load transfer from one feeder to another in the event of an emergency, outages or for planned load transfers. The location of these open points is generally well defined in the system and serves as the boundary references for each feeder. See drawing # H-SC-06034 in Appendix C.

The configuration of the distribution system is very robust and reliable. Uni-directional power flows from the transformer stations to the loads. However, there are a number of challenges associated with maintaining the reliability for customers when there is a two-way power flow caused by the presence of distributed generators on the system, as discussed below.

2.3.1 Protection and Coordination

With higher penetration of distributed renewable resources, there will be multiple sources of power feeding into a fault, due to reverse flow. Because of this, the current design of the system's protection equipment may require revision. All protection equipment installed upstream of a generator and downstream of a fault will need to be re-configured to detect and react to reverse power flow.

2.3.2 Unintentional Islanding of Generator(s)

All inverter based generators are designed to be of 'grid-sense' type. In event of a fault when the TS breaker opens, all the distributed generators will ideally sense the absence of voltage and/or frequency on the feeder and disconnect from the distribution system.

However, it is possible that with a strong cluster of sufficiently sized generators concentrated in a given section of the feeder, any one of the larger generators can potentially hold the voltage and frequency on this section of the feeder. This would in turn allow the other generators to remain connected or automatically re-connect thereby creating an 'island' within the distribution system.

BPI will continue to closely monitor the evolution of these distributed resources in its system and will further investigate the consequences and possible remedies for such situations.

2.3.3 Effect on System Power Factor

Inverter based generators produce only active power at unity power factor. The distribution system power factor on the other hand is the load power factor which is composed of the active and reactive power consumed.

If a large number of these generators are concentrated in a relatively small area of the distribution system, the active power produced by these generators would tend to compensate only the active component of the system power, thereby adversely affecting the overall power factor.

A possible remedy is to design and install reactors or capacitors at suitable locations throughout the system to adequately support the system power factor.

3.0 Planned Development of the System

3.1 Outlook and Objective

BPI's objective for the next five years is to accommodate all renewable generators that apply to connect to its distribution system, subject to the upstream constraints identified in the previous sections. BPI plans to identify potential bottlenecks and possible solution.

BPI intends to make its distribution system available to current and new generators without compromising reliability and safety for its load customers.

The mostly urban demography of Brantford Power's service territory justifies the expected growth in roof-top solar PVs as the predominant source of renewable generation. It is therefore likely that the majority of projects will be microFIT or capacity exempt FIT generators. Changes in BPI's distribution network will largely depend on the number, capacity and concentration of new generators relevant to the current layout of the distribution system. It is possible that, due to changes in generation growth patterns beyond our reasonable forecasts, BPI may be forced to upgrade the size of the service wires from single-phase to three-phase or to single-phase of a higher capacity. In such a case, BPI will pursue the appropriate regulatory treatment of any costs at that time.

3.2 Current Distributed Generation in Brantford

Brantford has a mostly urban demography with residential customers making up the bulk of BPI customer base. As such, opportunities and resources for setting up small to medium scale power generation plants are scarce and scattered mostly in the industrial zones in the city.

Currently, the City of Brantford has only one of the original 29 Non-Utility Owned Generators ("NUGs") in the Province of Ontario, which is an approximately 4MW co-generation unit, owned by a legacy merchant generator since the early 1990s. This generation unit supplies the grid on BPI's distribution system at 27.6kV.

In mid-2010 another 8MW methane-based renewable generator, through a Renewable Energy Standard Offer Program (RESOP) contract with the Ontario Power Authority ("OPA"), came on-line with an initial generation capacity around 5MW. This generator is owned and operated by Brantford Generation Inc., a subsidiary of Brantford Energy Corporation which is a corporation of the City of Brantford. This renewable generator is established on the City's only landfill site.

In addition, a number of FIT projects exist in BPI's service are in various stages of OPA contract approval, as set out in Table 2

Table 2: FIT Projects in Pipeline Brantford

Stage of Process Completion	**FIT Projects**	**Capacity (kW)**
Applications submitted but not processed	0	0
CIA completed	5	1500
Connection Cost Agreement executed	4	1250
Connection Agreement executed	1	50
Connected and generating	9	1365

Figures are reported as of July 2012

3.3 Planning Considerations

BPI is committed to connecting generation facilities and adhering to practices consistent with its distribution license, requirements set out in the GEGEA and the Distribution System Code ("DSC") and other applicable codes, standards and rules. BPI effectively plans for investments for renewable energy generation by:

- Comparing the forecast of renewable generation with BPI's capacity allocation standards;
- Determining the type of technical modifications required in BPI's distribution system to accommodate renewable generation connections;
- Considering system constraints.

3.4 Methods and Results from Demand Forecasting

BPI has employed the following strategies for forecasting demand for connection of renewable generation in its service territory:

- Researching relevant industry forecasts for the region (i.e. from the OPA), consultation with cohort group of LDCs of similar size and profile and feedback from the business community to gauge the level of interest in renewable generation in BPI's distribution service territory;
- Using information collected from GIS mapping of available roof-top space and potential PV generation capacity in BPI's service territory;
- Considering past experience with RESOP and other distributed generation connections, including information on which transformer stations and feeders have existing generation (capacity exempt) or capacity queued Connection Impact Assessments (CIAs) applications; and
- Applying information gathered from previous connection inquiries including generator size, type and volume of applications to anticipate impending generation connections.

3.4.1 Conclusions from Research

BPI monitors developments relevant to the GEGEA in order to make well-informed planning decisions. Additionally, BPI has participated in activities designed to gauge the level of interest in renewable generation in its service territory, as well as anticipated challenges and possible solutions.

In May 2010, BPI hosted a seminar for its commercial, industrial and institutional customers, which 17 firms attended. A follow-up survey conducted by BPI identified that only one firm in attendance showed interest in participating in the FIT program. This indicates that the most potential for renewable generation in Brantford lies in the residential sector.

BPI considers the province-wide trend in sources of renewable generation to be a strong indicator for forming its expectations of types of applications in its own service territory. Table 3 below sets out the numbers of OPA applications for FIT generation, by energy source. Solar PV is the source for 91% of the applications, which is consistent with BPI's evaluation that this will continue to represent most of the applications going forward.

Table 3: OPA FIT Contracts by Energy Source (Province-Wide)

Energy Source	Number of Contracts	Capacity (MW)
Hydroelectricity	49	188
Wind	77	3133
Bioenergy	50	59
Solar PV	1792	1206
Total	**1968**	**4586**

Source: OPA Report on Electricity Supply, Q1 2012

3.4.2 Estimated Solar PV Potential

From the GIS Rooftop Study set out in Appendix B, the estimated maximum generation capacity for Brantford from Solar PV = 176.86 MW

BPI does not currently have the ability to link customers or buildings to individual feeders. This prevents BPI from allocating the above forecast to specific feeders at this time. In the absence of this more accurate measure, BPI has utilized the average peak loading data from the previous five (5) years on BPI's feeders to estimate the percentage of customers serviced for each feeder. This is in turn used to predict the generation potential per feeder.

Table 4: Existing and Potential Generation per Feeder

TS / MTS	Number	Feeder	Percentage of 5 year Avg. System Load per feeder (%)	Estimated Potential Generation (MW)	CAE Applications (July, 2012)	Existing Generation on Feeders (MW)	Percent of Potential Generation (%)
Brantford	NA64						
		64M21	**6.63**	**11.73**	**1**	**0.5**	**4.15**
		64M22	**6.09**	**10.77**	**2**	**0.65**	**6.46**
		64M23	**4.43**	**7.83**	**0**	**0**	**0**
		64M24	**4.58**	**8.10**	**0**	**0**	**0**
		64M25	**6.22**	**11.00**	**2**	**0.2**	**2.43**
		64M26	**6.34**	**11.21**	**4**	**1.2**	**7.02**
		64M27	**9.14**	**16.17**	**0**	**0**	**0**
		64M28	**8.53**	**15.09**	**0**	**0**	**0**
		64M29	**7.35**	**13.00**	**2**	**0.335**	**3.39**
		64M30	**6.42**	**11.35**	**4**	**0.85**	**5.14**
Brant	NW12						
		12M12	**3.77**	**6.67**	**0**	**0**	**0**
		12M23	**6.68**	**11.81**	**1**	**0.065**	**0.53**
		12M13	**5.25**	**9.29**	**0**	**0**	**0**
Powerline	PMTS						
		PM1	**6.53**	**11.55**	**3**	**0.465**	**2.73**
		PM2	**5.86**	**10.36**	**2**	**0.35**	**1.07**
		PM3					
		PM7					
		PM8	**6.19**	**10.95**	**0**	**0**	**0**

3.4.3 Projections Based on Current Applications

Analysis of current applications

a) Micro-FIT
There are 54 micro-FIT generators connected to our distribution system as of September 2012 representing a total generation capacity of 371.176 kW.

b) FIT

Total number of contracts	21
Total new generation capacity (FIT)	4615 kW (4.615 MW)

The following graphs show the trend in cumulative generation applications from program start to August 2012, representing BPI's experience with FIT and microFIT applications. A linear average has been used to project the number of application from each program into the future.

Table 5: Micro-FIT Projections

From January 2010 to September 2012, BPI received 126 Micro-FIT applications. Based on the level of applications during this period, BPI expects to receive 46 new applications for Micro-FIT connection per year.

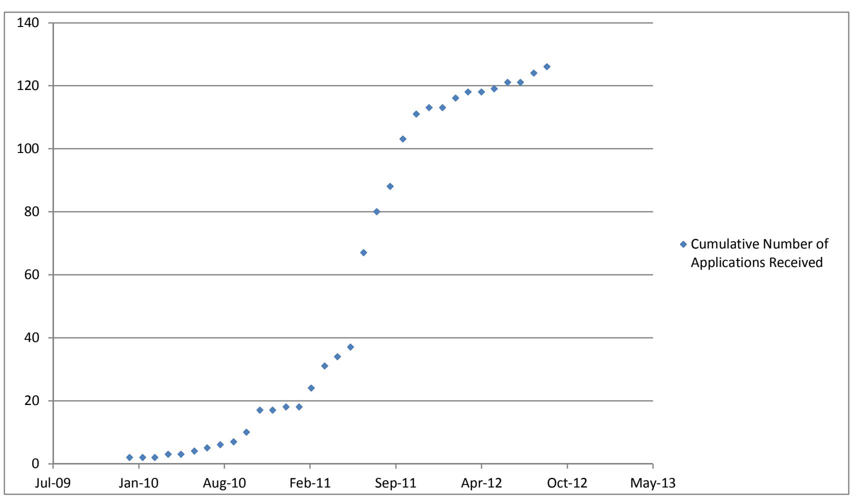
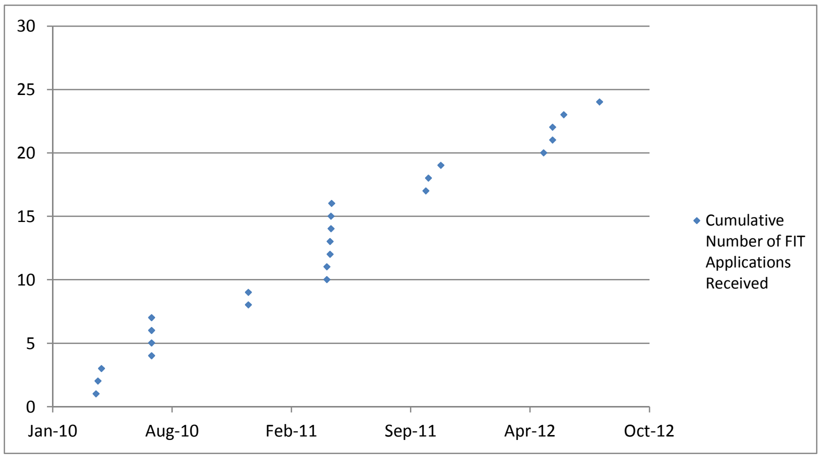


Table 6: FIT Application Projections

BPI has received 24 applications for FIT connection from January 2010 to August 2012. Based on the level of applications during this period, BPI expects to receive 9 new applications for FIT project connection each year.



3.5 OM&A Associated with Renewable Generation Connection

OM&A revenues would cover initial costs of development work related to generation connections. Investments in this area would allow BPI to undertake research and development to understand and address the complexities associated with generation connections and development of new standards for generation connections.

At this time, BPI is not recovering any OM&A costs associated with renewable generation through its current rates, and does not project any such costs over the term covered in this plan.

3.6 Capital Investments for Renewable Energy Generation

This section discusses capital investments on the distribution system for Connection, Expansion and Renewable Enabling Improvement assets required to connect renewable energy generation to the distribution system.

3.6.1 Investments in Connection Assets

Brantford Power assumes that a Connection Asset investment covers only the work associated with providing isolating devices or other assets required for the specific generator's connection to the distribution system. Consistent with the OEB issued amendments to the Distribution System Code in 2009, BPI does not include the expansion of its main distribution system to build a new line to the ownership demarcation point serving one or more generation customers as a Connection Asset.

Generators are responsible for all costs associated with Connection Assets. As such, the costs associated with work on the main distribution system to physically tap and isolate Connection Assets are covered by capital contributions from customers and result in no net capital increase to BPI's rate base, and no impact on distribution rates.

3.6.2 Investments in Expansions

This Plan is based on the assumption that expansion of the distribution system to connect renewable energy generation includes the following types of investments carried out to serve one or more of these facilities:

- Build the distribution system up to the ownership demarcation point of the renewable energy generation facility;
- Rebuild a single-phase line to a three-phase line;
- Upgrade a single-phase line to another single-phase line of higher capacity;
- Overbuild on an existing line to provide an additional circuit;
- Convert a lower voltage line to operate at higher voltage;
- Replace a transformer to one with a larger size;
- Add capacitor or reactor banks to maintain power quality;
- Build new express feeders; and
- Build a new transformer station.

There are no costs associated with expansion investments required to connect renewable generation facilities over the term of this Plan. For Expansion investments beyond BPI's reasonable projections, BPI will contribute up to the maximum expansion cost cap of $90,000 / MW of connecting generation capacity established under the DSC. Any incremental Expansion costs beyond the proposed cap are to be borne by the generator(s).

There is no capital cost of work on Expansions requested in this Plan.

3.6.3 Investments in Renewable Enabling Improvements (Enhancements)

REIs address modifications or additions to the main distribution system in order to accommodate increased levels of renewable energy generation mainly by eliminating some of the technical limitations to the connection of new generation. These investments will also dovetail with the development of the Smart Grid. REI investments include the following:

- Modifications or additions to manage and control 2-way electrical flows or reverse flows (e.g. bi-directional reclosers, tap changer controls or relays, replacing breaker protection relays);
- Modification or addition to electrical protection equipment;
- Addition of voltage regulating transformer or station controls;
- Provision of protection against islanding; and
- Modifications or additions to SCADA system.

REI investments will ensure proper protection, automation and control measures are in place to facilitate the connection and operation of renewable energy generation. These investments are also expected to benefit BPI load customers. Consistent with the requirements of Regulation 330/09, a portion of any future REI investment costs will be identified for recovery as they occur.

There are no costs for REI included in this plan or being funded through current rates.

Appendix A- Available Feeder Capacities for Generation Connections

POWERLINE MTS

	PM1	PM2	PM3	PM7	PM8
Generation Capacity (kW)	14535	10050	15000	15000	15000

BRANTFORD TS

	Y BUS					Z BUS				
	64M21	64M23	64M25	64M27	64M29	64M22	64M24	64M26	64M28	64M30
Generation Capacity (kW)	14500	15000	14800	15000	14665	0	0	0	0	0

BRANT TS

	12M12	12M13	12M23
Generation Capacity (kW)	10400	15000	14935

Appendix B- GIS Mapping for Roof-Top Solar PVs

Assumptions

CAE, micro-FIT, and CAR applications are considered for future growth forecasting. Currently there are no CAR applicants registered with the OPA for Brantford.

A. Results from Mapping Building Footprints

Roof-top surface area from GIS based on year 2000 data = 6,175,251.7637 m^2

Average load growth in the city for the past 5 years is estimated at 1.5%

Estimated roof-top area based on load growth projections to 2010 = 7,166,631.777 m^2

Estimated usable roof-top area = 2,284,363.88m^2 (~32%)

(It is estimated that the current roof-top structure of a typical building allows for one-half of the total surface area available for mounting solar panels. Of this approximately 75% of the space can be actually utilized due to loading and other structural considerations while 15% of all available roof-tops cannot be used at all due to their orientation with respect to the sun)

B. Generation Capacity

[1]Average efficiency of Solar PV panels = 15%

[1]Average corresponding surface area = 1.82 m^2.

[1]Average output from above = 235.8 Watts

This corresponds to 129.5 Watts/m2 or 11.89 Watts/ft^2

However, we would also consider the following variables to more accurately estimate the generated output from a typical Solar PV panel.

[2]De-rating Factor = 0.8

(The de-rating factor represents the amount of electricity lost in the conversion from direct current (dc) to alternating current (ac). The default value is 0.8 which corresponds to a 20% loss.)

[2]Tilt Angle = 43^0

(The tilt angle is the inclination from horizontal (0° = horizontal and 90° = vertical) of the PV array. For maximum utilization the tilt angle should be between these two values and depends upon the geographic location of the site.)

[2]Azimuth Angle = 180^0

(For a fixed PV array, the azimuth angle is the angle clockwise from true north that the PV array faces. The default value is 180° (south-facing) for locations in the northern hemisphere. This normally maximizes energy production. In the northern hemisphere, increasing the azimuth angle favors afternoon energy production, while decreasing the azimuth angle favors morning energy production.)

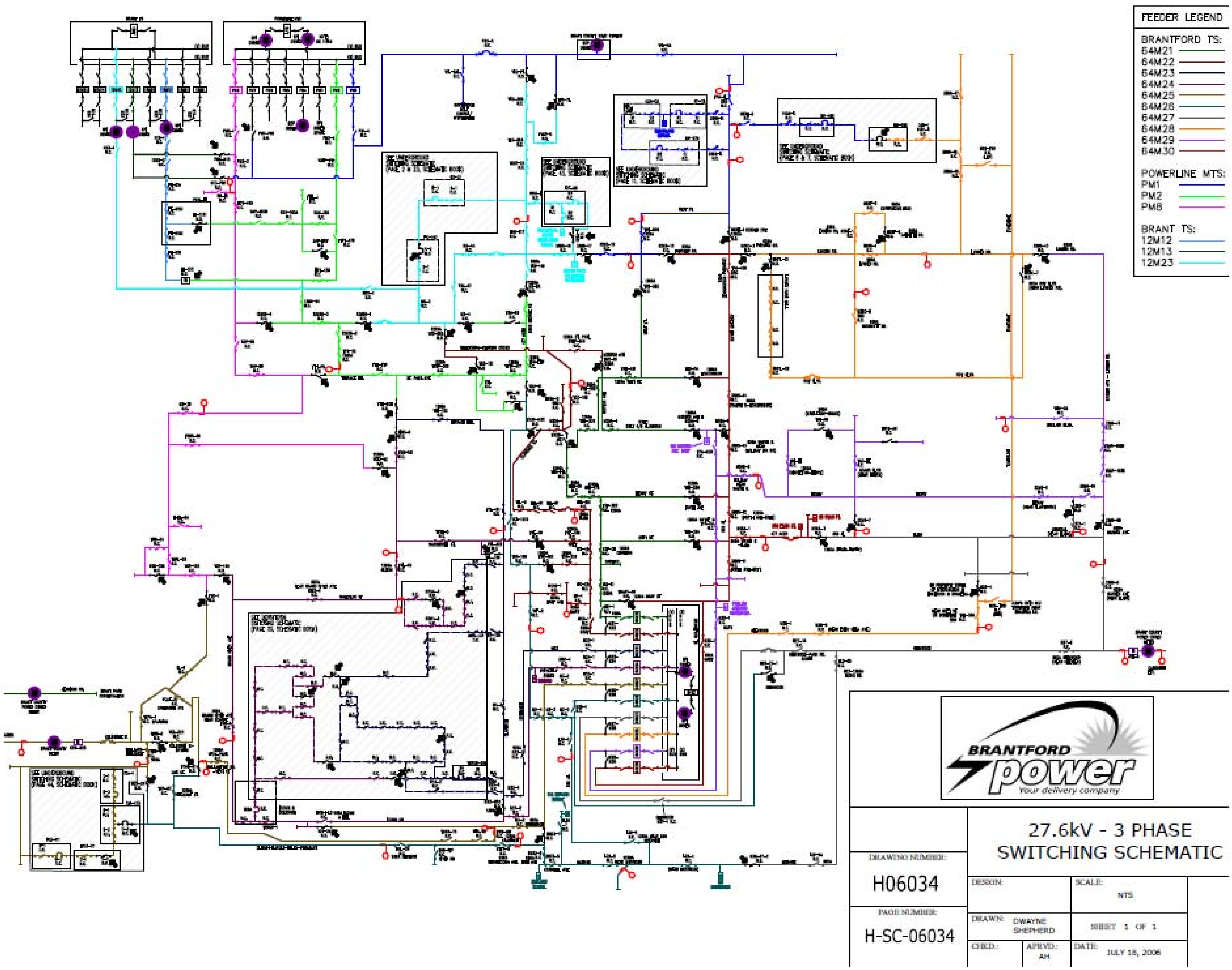
With the above parameters considered, the actual conversion is 110.6 Watts/m2 or 10.15 Watts/ft2.

Result: Estimated Solar PV Potential

We estimate a diversity factor of 70% (i.e. accounting for the percentage of load customers that will proceed to install a roof-top solar PV).

From the above parameters and adjustment factors, the estimated maximum generation capacity for Brantford from Solar PV = 176.86 MW

Appendix C - 27.6 kV Switching Schematic



FEEDER LEGEND
BRANTFORD TS:
64M21
64M22
64M23
64M24
64M25
64M26
64M27
64M28
64M29
64M30
POWERLINE MTS:
PM1
PM2
PM8
BRANT TS:
12M12
12M13
12M23
BRANTFORD power
Your delivery company
27.6kV - 3 PHASE
SWITCHING SCHEMATIC
DRAWING NUMBER:
H06034
PAGE NUMBER:
H-SC-06034
DESIGN:
SCALE:
NTS
DRAWN: DWAYNE SHEPHERD
SHEET 1 OF 1
CHKD.:
APRVD.: AH
DATE: JULY 18, 2006

APPENDIX F

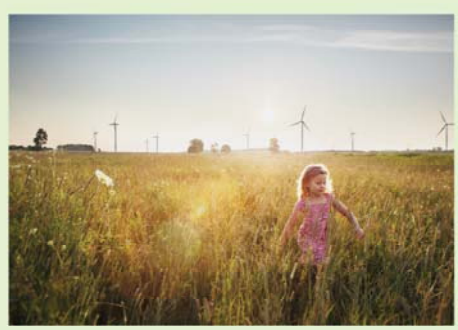
OPA LETTER OF COMMENT

OPA Letter of Comment:

Brantford Power Inc.

Basic Green Energy Act Plan

December 11, 2012



ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Brantford Power Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Brantford Power Inc. ("BPI") dated October, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

BPI's GEA Plan indicates that as of September 2012 a total of 126 microFIT projects and 24 FIT projects have applied to connect within BPI's service territory. Of these, 54 microFIT projects (totaling 0.371 MW) have been connected, and 21 FIT projects (totalling 4.615 MW) have received contracts. These have been itemized in Section 3.4.3: *Projections Based on Current Applications*, starting on page 13 of the Plan.

To date, the OPA has processed 95 microFIT applications totalling approximately 0.758 MW of capacity in BPI's service territory. Of these, approximately 0.365 MW have been offered a contract as of December 2012. Additionally, the OPA has received and offered contracts to 24 capacity allocation exempt FIT applications, totalling approximately 5.041 MW that have identified themselves as connecting within BPI's service territory. Of these, 21 applications totalling 4.406 MW remained active as of December 2012.

Upstream Transmission Constraints

As noted in BPI's Plan, the Brantford TS Z bus has been identified as a restricted station by Hydro One Networks due to short circuit limitations. This constraint poses limitations for both future FIT and microFIT applications connecting to the Brantford TS Z bus.

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Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that BPI's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Brantford Power Inc.'s Basic GEA Plan.

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Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1	1		Overview of Operating Revenue
	2	1		Weather Normalized Load and Customer/ Connection Forecast
			A	Monthly Data Used for Regression Analysis
	3	1		Operating Revenue Variance Analysis.
		2		Transformer Allowance
		3		Variance Analysis on Other Distribution Revenue
		4		Specific Service Charges

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of BPI’s operating revenue for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, the 2012 Bridge Year and the 2013 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

BPI is proposing a total Service Revenue Requirement of $17,864,601for the 2013 Test Year. This amount includes a Base Revenue Requirement of $16,703,454 plus revenue offsets of $1,161,146 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3.0 and provides a comparison of total revenues from the 2008 Board Approved year to the 2013 Test Year.

Throughput Revenue:

Information related to BPI’s throughput revenue, includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on the historical throughput revenue is also provided in this Exhibit.

Other Revenue:

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues and Merchandise and Jobbing Revenues.

A detailed variance analysis on other revenue is set out later on this Exhibit.

Table 3.0: Summary of Operating Revenue							
Distribution Revenue	2008 Board Approved*	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 test at proposed rates
Residential	$ 8,408,128	$ 8,446,939	$ 8,217,209	$ 8,549,417	$ 8,636,477	$ 8,599,371	$ 9,545,328
GS<50	$ 1,450,724	$ 1,461,018	$ 1,398,432	$ 1,411,955	$ 1,419,811	$ 1,437,538	$ 1,592,778
GS>50	$ 5,359,345	$ 4,550,787	$ 4,516,486	$ 4,367,983	$ 4,337,736	$ 4,442,452	$ 4,983,913
Streetlight	$ 101,753	$ 76,194	$ 113,929	$ 130,347	$ 135,989	$ 136,856	$ 157,703
USL	$ 78,499	$ 82,582	$ 80,094	$ 80,298	$ 79,528	$ 74,600	$ 80,547
Embedded Distributor	$ -	$ 295,547	$ 287,637	$ 564,797	$ 387,661	$ 402,904	$ 282,689
Standby**	$ 37,679	$ 61,118	$ 59,499	$ 62,478	$ 66,547	$ 64,532	
Sentinel	$ 21,416	$ 7,633	$ 20,541	$ 26,502	$ 28,264	$ 32,255	$ 60,496
Total	**$ 15,457,544**	**$ 14,981,818**	**$ 14,693,827**	**$ 15,193,777**	**$ 15,092,015**	**$ 15,190,508**	**$ 16,703,454**
% of total Revenue	*91.6%*	*90.8%*	*90.9%*	*91.8%*	*92.8%*	*93.4%*	*93.5%*
Other Distribution Revenue							
Specific Service Charges	$ 679,232	$ 589,631	$ 575,804	$ 635,867	$ 469,500	$ 403,588	$ 422,134
SSS Admin Fees		$ 93,320	$ 93,675	$ 96,005	$ 99,725	$ 103,910	$ 165,054
Late Payment Charges	$ 95,172	$ 108,433	$ 99,278	$ 7,651	$ 111,988	$ 122,798	$ 120,000
Other Operating Revenues** (net of SSS Admin Fees) *	$ 208,925	$ 200,066	$ 222,045	$ 188,791	$ 172,900	$ 155,998	$ 158,419
Other Income or Deductions	$ 439,000	$ 518,897	$ 484,428	$ 422,240	$ 313,666	$ 283,824	$ 295,539
Total	**$ 1,422,329**	**$ 1,510,346**	**$ 1,475,230**	**$ 1,350,554**	**$ 1,167,779**	**$ 1,070,118**	**$ 1,161,146**
% of total Revenue	*8.4%*	*9.2%*	*9.1%*	*8.2%*	*7.2%*	*6.6%*	*6.5%*
Grand Total	**$ 16,879,873**	**$ 16,492,164**	**$ 16,169,057**	**$ 16,544,331**	**$ 16,259,794**	**$ 16,260,626**	**$ 17,864,601**

* For2008 Board Approved SSS Admin Fees are included in Distribution Revenue

** In 2013 Test year only, Revenues from the Standby class are included as " Other Distribution Revenue" with SSS admin Fees

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by BPI to prepare the weather normalized load and customer/connection forecast used to design the proposed 2013 electricity distribution rates.

In summary, BPI has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, BPI submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. BPI has the data for the amount of electricity (in kWh) purchased from the IESO and other suppliers for use by BPI's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later in this Exhibit.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. During the review process of the 2009 cost of service applications, intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly kWh by rate class. BPI attempted such analyses, but found them to produce statistically weak results, with R-squared statistics far below 80% for most classes. In BPI's view, this would not be an appropriate basis for its load forecast.

During the review of 2010 cost of service applications, Board staff and intervenors expressed concern that the regression analysis assigned coefficients to some variables that were counterintuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management ("CDM") savings in the utility but in the view of Board staff and intervenors, this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation[1]. BPI has attempted to address these concerns in the load forecast used in this Application. Based on the Board's approval of this methodology in a number of previous cost of service applications[2] and based on the discussion that follows, BPI submits that its load forecasting methodology is reasonable at this time for the purposes of this Application.

The following Table 3.1 provides the material to support the weather normalized load forecast used by BPI in this Application.

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[1] For example, see Burlinton Hydro Inc.'s 2010 cost of service distribution rate application (EB-2009-0259) and Festival Hydro Inc.'s 2010 cost of service distribution rate application (EB-2009-0263).
[2] For example, see Innisfil Hydro Distribution System Limited (EB-2012-0139), Lakeland Power Distribution Ltd. (EB-2012-0145), London Hydro Inc. (EB-2012-0146), Midland Power Utility Corporation (EB-2012-0147), and Welland Hydro Electric System Corp. (EB-2012-0173).

Table 3.1: Summary of Load and Customer/ Connection Forecast						
Year	**Billed kWh**	**Growth**	**percent change**	**customer/connection count**	**growth**	**percent change**
2008 Board Approved	1,005,573,694					
2003 Actual	913,442,956			42,860		
2004 Actual	949,864,834	36,421,878	4.0%	43,629	769	1.8%
2005 Actual	985,555,339	35,690,505	3.8%	44,676	1,047	2.4%
2006 Actual	987,570,495	2,015,156	0.2%	45,798	1,122	2.5%
2007 Actual	1,004,831,701	17,261,206	1.7%	46,902	1,105	2.4%
2008 Actual	977,884,255	(26,947,446)	-2.7%	45,322	(1,581)	-3.4%
2009 Actual	912,366,781	(65,517,474)	-6.7%	47,651	2,330	5.1%
2010 Actual	917,169,662	4,802,881	0.5%	48,014	363	0.8%
2011 Actual	915,803,475	(1,366,187)	-0.1%	48,792	778	1.6%
2012Actual	931,554,498	15,751,023	1.7%	49,270	477	1.0%
2013 Normalized Test	**919,877,738**	**(11,676,760)**	**-1.3%**	**49,975**	**705**	**1.4%**

The information in Table 3.1 above provides weather actual data from 2003 to 2012, while 2013 is weather normalized. BPI does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a yearly average basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers are shown in Table 3.2 and customer usage is shown in Table 3.3, on a rate class basis.

Table 3.2: Billed Energy and Number of Customers/ Connections by Rate Class							
			Billed Energy				
Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL	Total
2008 Board Approved	294,990,955	110,476,190	588,310,448	7,244,141	549,290	2,335,344	1,003,906,368
2003 Actual	270,806,559	95,006,443	539,007,863	6,116,876	0	2,505,215	913,442,956
2004 Actual	269,489,820	96,978,252	574,507,768	6,269,377	0	2,619,617	949,864,834
2005 Actual	293,232,137	103,223,115	580,021,347	6,635,713	0	2,443,027	985,555,339
2006 Actual	281,767,239	102,615,621	594,077,901	6,975,374	0	2,134,360	987,570,495
2007 Actual	285,310,578	105,113,198	605,456,649	7,101,501	0	1,849,775	1,004,831,701
2008 Actual	278,923,645	104,110,563	585,927,516	7,240,798	0	1,681,733	977,884,255
2009 Actual	275,417,341	99,603,717	528,476,684	7,316,579	0	1,552,460	912,366,781
2010 Actual	287,357,342	98,691,975	521,725,747	7,354,351	480,615	1,559,632	917,169,662
2011 Actual	289,048,493	98,344,763	519,052,260	7,337,049	465,459	1,555,451	915,803,475
2012 Actual	284,844,991	99,625,182	537,717,579	7,395,384	435,374	1,535,988	931,554,498
2013 Normalized Test	**280,913,502**	**97,535,297**	**531,977,718**	**7,553,004**	**443,490**	**1,454,727**	**919,877,738**

Table 3.3: Number of Customers/ Connections

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL	Total
2008 Board Approved	33,818	2,675	413	10,056	788	435	48,185
2003 Actual	31,105	2,428	394	8,434	0	499	42,860
2004 Actual	31,707	2,445	391	8,578	0	508	43,629
2005 Actual	32,252	2,482	392	9,048	0	502	44,676
2006 Actual	32,754	2,549	397	9,328	317	452	45,798
2007 Actual	33,237	2,640	410	9,610	569	438	46,902
2008 Actual	33,645	2,707	405	7,540	586	440	45,322
2009 Actual	33,929	2,700	409	9,577	592	444	47,651
2010 Actual	34,219	2,684	418	9,644	605	445	48,014
2011 Actual	34,621	2,705	421	9,981	620	444	48,792
2012 Actual	34,913	2,729	417	10,145	624	443	49,270
2013 Normalized Test	**35,364**	**2,764**	**420**	**10,355**	**635**	**437**	**49,975**

In the course of preparing its load forecast, BPI identified some anomalous billing treatment for the Sentinel lights class, resulting in incomplete data. Accurate customer numbers are only available beginning with 2006 and billed kWh data was only available beginning in 2010.

LOAD FORECAST AND METHODOLOGY

BPI's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, days in the month and customer data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The load forecast for the 2013 Test Year as summarized in Table 3.21, was approved by BPI's Senior Leadership Team following several internal consultation workshops.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); days in month, Real Ontario GDP, Negative Impact Variable, and several monthly flag variables. The monthly flag variables control for seasonal variability in power purchases during the spring and fall months beyond variability caused by Heating Degree Days ("HDD") and Cooling Degree Days ("CDD"). The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2012 to determine the monthly regression coefficients. This provides 120 monthly data points, representing a reasonable data set for use in a regression analysis.

BPI submits that for weather normalization purposes it is appropriate to determine the average weather conditions from January 2003 to December 2012 as this reflects the time period over which the regression analysis has been conducted. However, in accordance with the Board's Filing Requirements, BPI has also provided a sensitivity analysis showing the impact on the 2013 forecast of purchases assuming weather normal conditions are based on a 20-year trend of weather data, below in Table 3.6.

The multifactor regression model has determined drivers of year-over-year changes in BPI's load growth; these include weather (including the fall and spring monthly flags), number of days in the month, number of customers, and Negative Impact Variable. These factors are captured within the multifactor regression model.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by BPI to predict weather normal purchases for 2012 and 2013:

BPI's Monthly Predicted Weather Normal Purchases =

(53,960,036.90)

+ Heating Degree Days * 15,963

+ Cooling Degree Days * 110,374

+ Number of Days in Month * 1,909,211

+ Real Ontario GDP (chained in $1997 with base 100 in 1997) * 549,023

+ April* (4,364,939)

+ May * (3,385,062)

+ October Flag * (2,029,354)

+Negative Impact Variable * (5.71)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website was used for monthly heating degree day and cooling degree information. Weather data was taken from the Pearson Airport CS Station. Data from Hamilton stations was considered; however of the 3 weather stations in Hamilton, none has continuous, consistent daily weather data over the full time period necessary.

b) The calendar provided information related to number of days in the month.

c) The number of customers was based on historical information from the BPI billing system

d) The Negative Impact Variable grows each month at a constant value over the year. The negative impact variable not only reflects the impact of CDM on the load forecast but it also reflects the impact of economic conditions within the service area.

e) For 2003 to 2006 the source of data for the Ontario Real GDP information was the 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance. For 2007 and 2009, the source was the 2010 Ontario Economic Outlook and Fiscal Review - 2010 Fall Update. For 2010, the 2011 Ontario Economic Outlook and Fiscal Review - 2011 Fall Update provided the Ontario Real GDP for that year. For 2011 to 2013, the 2013 Ontario Budget was the source for the Ontario Real GDP data.

For the years 2006 to 2013, the addition of the monthly negative impact variable shown in Appendix A of this Exhibit will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for BPI. These values reflect the net energy savings from 2006 to 2010 programs and how the savings from these programs have persisted from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include the 2011 and 2012 results of programs that contribute to the four year licensed CDM kWh target of 48,920,000 kWh assigned to BPI. The 2011 Final results are based on the 2011 Results Report provided to BPI by the OPA on August 31, 2012. The 2011 final results have been included in the Negative Impact Variable since these results have impacted the actual 2011 power purchases. BPI has also included a forecast of

2012 results based on the calculations in Table 3.15 for future CDM Savings. At the time of the preparation of this Application, OPA Final results for 2012 were not available.

The following table outlines the adjustments made to the Net Energy Savings from the OPA 2006-2010 Final CDM Results to include the impact of the final verified results from 2011 CDM programs and forecast 2012 programs and the persistent impact of these 2011 and 2012 programs into 2013. In addition, the table provides the Net Energy Savings from the OPA 2006-2010 Final CDM Results for the years 2006 to 2013. For 2013, the monthly values for the CDM activity variable will total 22,462,102 kWh which includes 12,795,202 kWh from the OPA final results plus 4,498,762 kWh reflecting the persistence of 2011 programs into 2013, plus 5,168,137 kWh reflecting the persistence of 2012 programs into 2013.

Table 3.4: Results and Persistent Impact of 2006-2010 and 2011 Final OPA Results, Forecasted 2012 Results

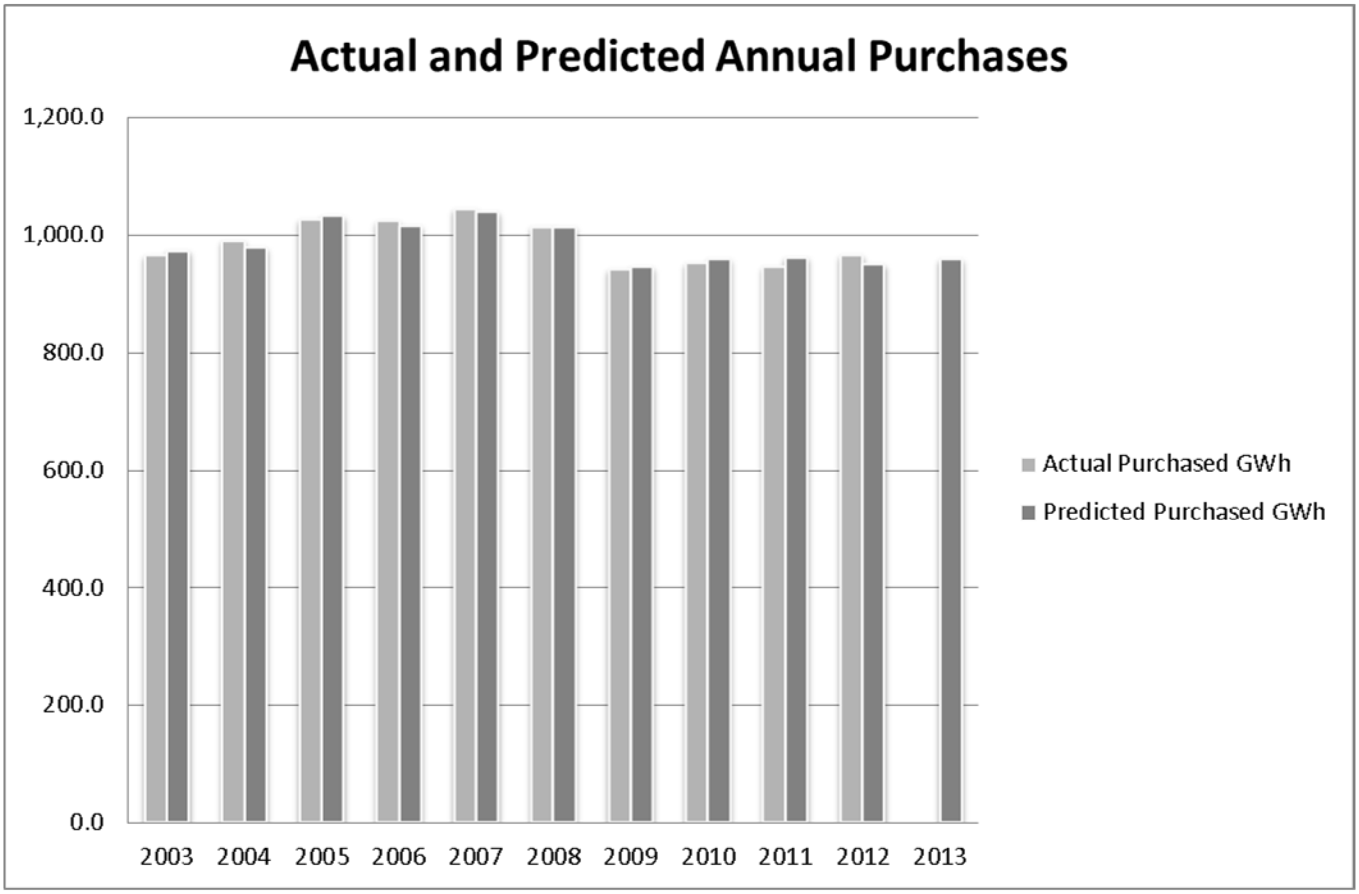
	Impact of 2006-2010 OPA Programs (kWh)	Impact of 2011 Programs (kWh)	Impact of 2012 Programs (kWh)	Total kWh savings
2006	2,666,105			2,666,105
2007	4,053,225			4,053,225
2008	6,738,513			6,738,513
2009	13,068,447			13,068,447
2010	14,323,507			14,323,507
2011	13,147,196	4,515,479		17,662,675
2012	12,916,363	4,502,851	5,168,137	22,587,351
2013	12,795,202	4,498,762	5,168,137	22,462,102

The impact of 2013 CDM programs has not been included in the Negative Impact variable since they do not impact the actual purchases used in the regression analysis. A discussion on how the load forecast is adjusted for 2013 programs and how LRAM variance account values are determined by rate class is provided later on in this schedule.

The prediction formula has the following statistical results:

Table 3.5: Regression Statistics	
Multiple R	95.7%
R Square	91.6%
Adjusted R Square	91.0%
ANOVA	
	df
Regression	8
Residual	111
Total	119
	t Stat
Intercept	(5.46)
Heating Degree Days	14.90
Cooling Degree Days	19.19
Number of Days in Month	8.01
Real Ontario GDP (chained $1997 with Base 100 in 1997)	10.59
April	(6.47)
May	(4.63)
October	(2.81)
Negative Impact Variable	(15.55)

The annual results of the above prediction formula compared to the actual annual purchases from 2003 to 2012 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.



The following Table 3.6 outlines the data that supports the above chart. In addition, the predicted total system purchases for BPI are provided for 2013. Values for 2013 are also provided with a 20 year trend assumption for weather normalization.

Table 3.6: Total System Purchases (GWh)			
Year	Actual	Predicted	% Difference
2003	964.3	972.2	0.82%
2004	989.6	977.2	-1.26%
2005	1,025.7	1,031.3	0.55%
2006	1,022.8	1,015.1	-0.76%
2007	1,043.0	1,038.4	-0.44%
2008	1,013.4	1,013.0	-0.04%
2009	940.8	944.6	0.40%
2010	950.8	958.0	0.76%
2011	944.9	961.0	1.70%
2012	964.4	948.9	-1.61%
2013 Weather Normal- 10 year average		957.8	
2013 Weather Normal- 20 year trend		961.6	

The weather normalized amount for 2013 is determined by using 2013 independent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2003 to December 2012 (i.e. ten years). The 2013 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1993 to December 2012.

The weather normal ten year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The ten year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by BPI using the average loss factor from 2003 to 2012 of 1.0383. With this average loss factor the total weather normalized billed energy will be 922.5 GWh for 2013 (i.e. 957.8/1.0383), and 919.9 GWh after the adjustment for CDM discussed below.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 3.7: Historical Number of Customers/ Connections

Year	Residential	GS<50	GS>50	Streetlight	Sentinel	USL	Total
2008 Board Approved	33,818	2,675	413	10,056	788	435	48,185
2003 Actual	31,105	2,428	394	8,434	0	499	42,860
2004 Actual	31,707	2,445	391	8,578	0	508	43,629
2005 Actual	32,252	2,482	392	9,048	0	502	44,676
2006 Actual	32,754	2,549	397	9,328	317	452	45,798
2007 Actual	33,237	2,640	410	9,610	569	438	46,902
2008 Actual	33,645	2,707	405	7,540	586	440	45,322
2009 Actual	33,929	2,700	409	9,577	592	444	47,651
2010 Actual	34,219	2,684	418	9,644	605	445	48,014
2011 Actual	34,621	2,705	421	9,981	620	444	48,792
2012 Actual	34,913	2,729	417	10,145	624	443	49,270

From the historical customer/connection data the growth rates in customers/connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2003 to 2012.

Table 3.8: HistoricalGrowth in Customers per Class

	Residential	GS<50	GS>50	Sentinels	Streetlights	USL
2004	1.9%	0.7%	-0.6%		1.7%	1.9%
2005	1.7%	1.5%	0.2%		5.5%	-1.3%
2006	1.6%	2.7%	1.3%		3.1%	-9.9%
2007	1.5%	3.6%	3.1%		3.0%	-3.2%
2008	1.2%	2.5%	-1.1%	3.1%	-21.5%	0.5%
2009	0.8%	-0.2%	1.0%	1.1%	27.0%	1.0%
2010	0.9%	-0.6%	2.2%	2.1%	0.7%	0.1%
2011	1.2%	0.8%	0.7%	2.5%	3.5%	-0.2%
2012	0.8%	0.9%	-0.9%	0.5%	1.6%	-0.2%
Geomean	1.3%	1.3%	0.6%	1.9%	2.1%	-1.3%

The numbers for projected customers per class for 2013 were determined by increasing the 2012 actual number of customers in each class by the geomean growth rate calculated above.

Table 3.9: Projected Customers Per Class

	Residential	GS<50	GS>50	Sentinels	Streetlights	USL	Total
2013	35,364	2,764	420	635	10,355	437	49,975

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2003 to 2012

Table 3.10: Historic Annual Usage per Class

	Residential	GS<50	GS>50	Sentinels	Streetlights	USL
2003	8,706	39,128	1,369,489	0	725	5,026
2004	8,500	39,665	1,467,765	0	731	5,155
2005	9,092	41,594	1,479,332	0	733	4,870
2006	8,602	40,259	1,495,790	0	748	4,720
2007	8,584	39,822	1,478,226	0	739	4,226
2008	8,290	38,467	1,446,437	0	960	3,823
2009	8,117	36,891	1,291,856	0	764	3,494
2010	8,398	36,777	1,247,899	794	763	3,505
2011	8,349	36,351	1,233,392	750	735	3,503
2012	8,159	36,513	1,289,233	698	729	3,467

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table 3.11: Change in Annual Customer Usage per Class

	Residential	GS<50	GS>50	Sentinels	Streetlights	USL
2004	-2.4%	1.4%	7.2%		0.8%	2.6%
2005	7.0%	4.9%	0.8%		0.3%	-5.5%
2006	-5.4%	-3.2%	1.1%		2.0%	-3.1%
2007	-0.2%	-1.1%	-1.2%		-1.2%	-10.5%
2008	-3.4%	-3.4%	-2.2%		30.0%	-9.5%
2009	-2.1%	-4.1%	-10.7%		-20.4%	-8.6%
2010	3.5%	-0.3%	-3.4%		-0.2%	0.3%
2011	-0.6%	-1.2%	-1.2%	-5.5%	-3.6%	-0.1%
2012	-2.3%	0.4%	4.5%	-7.0%	-0.8%	-1.0%
Used	-0.7%	-0.8%	-0.7%	0.0%	0.1%	-4.0%
Geomean	-0.7%	-0.8%	-0.7%	-6.2%	0.1%	-4.0%

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2012 usage to determine the 2013 forecast. Given the limited data for the Sentinel Light class, and the nature of electricity consumption in this class, a rate of 0% growth has been used instead of the geomean for the Sentinel Light class. The resulting usage forecast is as follows:

Table 3.12: Forecast kWh Usage Per Customer Per Class

	Residential	GS<50	GS>50	Sentinels	Streetlights	USL
2013	8,100	36,233	1,280,611	698	729	3,327

With the preceding information the non-weather-normalized billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3.9 by the forecast of annual usage per customer/connection from Table 3.12. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 3.13: Non-Weather Normal Billed Energy Forecast per Class (GWh)							
	Residential	*GS<50*	*GS>50*	*Sentinels*	*Streetlights*	*USL*	*Total*
2013	286.4	100.2	537.6	0.4	7.6	1.5	933.6

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 919.9 GWh for 2013.

The difference between the non-normalized and normalized forecasts is (13.7) GWh (i.e. 933.6 – 919.9). (2.6 GWh) of this adjustment is due to the CDM manual adjustment recognizing the impact of 2013 CDM program savings in 2013. The remaining (11.2) GWh is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for BPI for the cost allocation information filing, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3.14: Weather Sensitivity by Rate Class						
	Residential	GS<50	GS>50	Sentinels	Streetlights	USL
Percent Weather Sensitive	67.00%	67.00%	34.00%	0.00%	0.00%	0.00%

For the GS > 50 kW class the weather sensitivity amount of 34% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. BPI agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, BPI has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 34%, or 67%.

The difference between the non-weather normalized and normalized forecast of 11.2 GWh in 2013 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

CDM Adjustment

In addition a manual adjustment has been made to reflect the impact of 2013 CDM programs on the load forecast. This adjustment reflects the net impact of 2013 CDM programs on the load forecast. BPI has included a net manual CDM adjustment consistent with the methodology recently approved by the Board in its Decision on Centre Wellington Hydro Ltd.'s 2013 Cost of Service Application (EB-2012-0113).As previously discussed, the final 2011 savings from 2011 CDM programs are known and have been used in the CDM activity variable included in the regression analysis supporting the prediction formula. However, the 2011 Final Results also impact the expected savings from 2012 to 2014 programs in order to achieve the 4 year CDM target set out in BPI's distribution licence. Based on the following table, the 2011 final savings will contribute 36.6% to the four year target. In the following table, the 2011 results are consistent with the information provided in Table 3.4. The table indicates that assuming persistence, 2012 to 2014 programs will need to achieve 10.6% of the four year target each year in order to achieve the target.

This 10.6% has been used in the Negative Impact Variable in the regression analysis, to reflect the impact of 2012 CDM programs which would have been in place in 2012 on actual purchased power for that year.

Table 3.15: Schedule to Achieve 4-year kWh CDM Target

4 Year 2011 to 2014 target				
48,920,000				
2013 Proposed Cost of Service Method				
2011	2012	2013	2014	Total
9.2%	9.2%	9.2%	9.0%	36.6%
	10.6%	10.6%	10.6%	31.7%
		10.6%	10.6%	21.1%
			10.6%	10.6%
9.2%	19.8%	30.3%	40.7%	100.0%
4,515,479	4,502,851	4,498,762	4,394,084	17,911,176
	5,168,137	5,168,137	5,168,137	15,504,412
		5,168,137	5,168,137	10,336,275
			5,168,137	5,168,137
4,515,479	9,670,988	14,835,037	19,898,496	48,920,000

The above table suggests that for 2012 programs, the savings in 2012 will be 5,168,137 kWh on a net basis and the persisting savings into 2013 will be 5,168,137 kWh. As discussed above in regards to the Negative Impact Variable, the savings from 2012 programs in 2012, and their persistence into 2013 have been reflected in the prediction formula.

The above table also suggests that in 2013, the savings from 2013 programs will be 5,168,137 kWh on a net basis. However, to address the concerns of Board Staff and intervenors in recent COS applications and consistent with the approach adopted in numerous settlement agreements, BPI has included only half of the 2013 net amount as the manual adjustment. This has been done to reflect that the full savings from CDM for 2013 will not be in place starting January 1st of the year, but rather will come into effect gradually over the year. BPI has therefore adjusted the 2013 load forecast by 2,584,069 kWh

In BPI's view, the 2013 load forecast should be adjusted by 2,584,069 kWh to reflect CDM savings from 2013 programs. This amount has been subtracted from the 2013 Billed kWh forecast.

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management [EB-2012-0003], issued April 26, 2012, it is BPI's understanding that as part of this Application expected CDM savings in 2013 from 2011, 2012 and 2013 programs will need to be established for LRAM variance accounts purposes. It is also BPI's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is BPI's view the units used for the 2013 LRAM variance account should also be on a net basis. Based on the net information in table 3.15, BPI expects to achieve 14,835,037 net kWh savings in 2013 from 2011 to 2013 CDM programs. For LRAM variance account purposes, the following table outlines how these expected savings have been allocated to rate classes using the 2013 information from Table 3.15. The expected kW savings have also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from table 3.17 in this Exhibit.

Table 3-16: Projected CDM Savings per Class			
	2011 Net Energy Sav	2011 Share of savings per class	2013 expected CDM savings per class
Residential	1,197,730	**27%**	3,934,990
GS<50	1,609,340	**36%**	5,287,283
GS>50- kWh*	1,708,410	**38%**	5,612,764
Total kWh savings expected	**4515480**	**100%**	**14,835,037**
KW/KWH ratio for GS>50		*0.25%*	
GS>50-kW			*14,268*
* Results from Pre-2011 programs have been included in the GS>50 kW class			

The following table outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast.

Table 3.17: Alignment of Normalized and Non-Normalized Forecasts

	Residential	GS<50	GS>50	Sentinels	Streetlights	USL	Total
Non Weather Corrected Forecast	286,449,066	100,152,041	537,574,405	443,490	7,553,004	1,454,727	933,626,732
Weather Sensitivity							
% Weather Sensitive	*67.0%*	*67.0%*	*34.0%*	-	-		
Allocation of Weather Sensitive Amount	(4,850,140)	(1,695,769)	(4,619,017)	-	-	-	(11,164,925)
CDM							
% allocated per class	*26.5%*	*35.6%*	*37.8%*				
kWh Allocated Per Class	(685,424)	(920,975)	(977,670)	-	-	-	(2,584,069)
Weather Corrected Forecast	280,913,502	97,535,297	531,977,718	443,490	7,553,004	1,454,727	919,877,738

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on per kW basis. These include GS > 50 kW, Streetlights, and Street lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWh and applying the average ratio to the forecasted kWh to produce the required kW.

The following Table 3.18 outlines the annual demand units by applicable rate class.

Table 3.18: Historic KW per Applicable Class

	GS>50	Sentinels	Streetlights	Total
2003	1,339,301		20,270	1,359,571
2004	1,416,806		19,077	1,435,883
2005	1,575,503		20,301	1,595,804
2006	1,501,228		21,299	1,522,527
2007	1,516,185		21,758	1,537,943
2008	1,477,384		22,064	1,499,448
2009	1,336,469		22,380	1,358,849
2010	1,325,334	1,470	22,480	1,349,283
2011	1,343,794	1,423	24,297	1,369,514
2012	1,386,954	1,331	22,533	1,410,819

The following Table 3.19 illustrates the historical ratio of kW/kWh as well as the average ratio for 2003 to 2011.

Table 3.19: Historic kW/kWh Ratio per Class

	GS>50	Sentinels	Streetlights
2003	0.2485%		0.3314%
2004	0.2466%		0.3043%
2005	0.2716%		0.3059%
2006	0.2527%		0.3053%
2007	0.2504%		0.3064%
2008	0.2521%		0.3047%
2009	0.2529%		0.3059%
2010	0.2540%	0.3058%	0.3057%
2011	0.2589%	0.3058%	0.3312%
2012	0.2579%	0.3058%	0.3047%
Average	0.2546%	0.3058%	0.3105%

The average ratio was applied to the weather normalized billed energy forecast in Table 3.17 to provide the forecast of kW by rate class as shown below. The following table outlines the forecast of kW for the applicable rate classes.

Table 3.20: Forecast kW per Applicable Class

	GS>50	Sentinels	Streetlights	Total
2013	1,354,270	1,356	23,455	1,379,081

In addition to the forecasts per class set out above, which are calculated in BPI's load forecast regression analysis, BPI has also forecast the Test Year billing determinants expected for its Embedded Distributor and Standby classes. The forecast kW usage for the Embedded Distributor Class is 155,806 kW. This is based on the average yearly kW in this class for the years 2010-2012. The forecast billing determinant for the Standby class is 36,000 kW. This corresponds to the annualized minimum reserved capacity for this class. BPI notes that the Standby kW forecast differs from the kW forecasts for the other classes, as it denotes kW of reserved capacity rather than kW of energy consumption.

Table 3.21 provides a summary of the billing determinants by rate classes that are used to develop the proposed rates.

APPENDIX A

MONTHLY DATA USED FOR REGRESSION ANALYSIS

	Total Purchases	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Real Ontario GDP (chained $1997 with Base 100 in 1997)	April	May	October	Negative Impact Variable	Predicted Purchases
Jan-03	87,388,286	815	-	31	125.66	0	0	0	0	87,217,802
Feb-03	79,249,838	699	-	28	125.81	0	0	0	0	79,726,415
Mar-03	81,540,901	581	-	31	125.95	0	0	0	0	83,652,077
Apr-03	74,201,337	373	2	30	126.10	1	0	0	0	74,393,099
May-03	72,603,730	178	-	31	126.24	0	1	0	0	73,991,138
Jun-03	77,278,956	43	53	30	126.39	0	0	0	0	79,239,113
Jul-03	90,974,807	0	118	31	126.54	0	0	0	0	87,757,646
Aug-03	81,817,315	2	128	31	126.68	0	0	0	0	88,937,545
Sep-03	78,164,432	55	24	30	126.83	0	0	0	0	76,474,474
Oct-03	78,072,590	276	-	31	126.98	0	0	1	0	77,315,494
Nov-03	79,241,459	399	-	30	127.12	0	0	0	0	79,471,924
Dec-03	83,752,558	562	-	31	127.27	0	0	0	0	84,064,018
Jan-04	90,837,491	849	-	31	127.53	0	0	0	0	88,798,917
Feb-04	83,093,877	632	-	29	127.80	0	0	0	0	81,654,360
Mar-04	85,032,643	487	-	31	128.06	0	0	0	0	83,312,246
Apr-04	76,314,845	332	-	30	128.32	1	0	0	0	74,695,878
May-04	76,988,030	159	9	31	128.59	0	1	0	0	75,924,087
Jun-04	80,201,463	44	32	30	128.85	0	0	0	0	78,253,009
Jul-04	84,364,755	4	86	31	129.12	0	0	0	0	85,708,355
Aug-04	83,757,950	13	60	31	129.38	0	0	0	0	83,043,202
Sep-04	81,122,721	30	41	30	129.65	0	0	0	0	79,523,988
Oct-04	78,913,063	226	2	31	129.92	0	0	1	0	78,302,148
Nov-04	81,423,641	379	-	30	130.19	0	0	0	0	80,842,805
Dec-04	87,558,513	643	-	31	130.45	0	0	0	0	87,118,272
Jan-05	91,714,412	770	-	31	130.74	0	0	0	0	89,298,381
Feb-05	81,076,815	616	-	28	131.03	0	0	0	0	81,278,369
Mar-05	87,176,799	609	-	31	131.33	0	0	0	0	87,041,389
Apr-05	75,263,673	307	-	30	131.62	1	0	0	0	76,109,849
May-05	78,470,578	189	1	31	131.91	0	1	0	0	77,373,785
Jun-05	92,848,969	9	146	30	132.20	0	0	0	0	92,188,745
Jul-05	94,845,399	-	189	31	132.50	0	0	0	0	98,797,081
Aug-05	93,143,275	0	141	31	132.79	0	0	0	0	93,663,988
Sep-05	80,842,300	23	52	30	133.09	0	0	0	0	82,495,222
Oct-05	79,268,420	220	8	31	133.38	0	0	1	0	80,780,118
Nov-05	82,590,728	388	-	30	133.68	0	0	0	0	82,909,161
Dec-05	88,412,660	665	-	31	133.98	0	0	0	0	89,401,660
Jan-06	88,782,670	552	-	31	134.25	0	0	0	34,181	87,546,113
Feb-06	82,652,726	604	-	28	134.53	0	0	0	68,362	82,613,107
Mar-06	87,287,263	517	-	31	134.81	0	0	0	102,543	86,897,664
Apr-06	76,130,011	293	-	30	135.08	1	0	0	136,723	77,016,164
May-06	81,448,519	137	26	31	135.36	0	1	0	170,904	80,235,875
Jun-06	86,666,222	20	74	30	135.64	0	0	0	205,085	85,049,309
Jul-06	96,205,464	-	167	31	135.92	0	0	0	239,266	96,947,457
Aug-06	91,965,539	4	102	31	136.20	0	0	0	273,447	89,721,362
Sep-06	78,075,371	81	13	30	136.48	0	0	0	307,628	79,205,081
Oct-06	81,808,423	288	1	31	136.76	0	0	1	341,808	81,052,342
Nov-06	83,973,333	382	-	30	137.04	0	0	0	375,989	82,509,408
Dec-06	87,799,550	501	-	31	137.33	0	0	0	410,170	86,266,771
Jan-07	92,807,711	647	-	31	137.55	0	0	0	399,031	88,795,102
Feb-07	87,369,732	740	-	28	137.78	0	0	0	387,893	84,740,386
Mar-07	89,810,436	547	-	31	138.01	0	0	0	376,754	87,569,330
Apr-07	80,121,095	356	-	30	138.23	1	0	0	365,615	78,446,183
May-07	80,608,589	136	22	31	138.46	0	1	0	354,477	80,484,764
Jun-07	89,502,716	17	99	30	138.69	0	0	0	343,338	88,712,580
Jul-07	89,014,824	3	106	31	138.92	0	0	0	332,199	91,360,455
Aug-07	94,084,356	5	141	31	139.15	0	0	0	321,061	95,434,042
Sep-07	82,681,855	37	48	30	139.38	0	0	0	309,922	83,900,662
Oct-07	83,253,588	138	20	31	139.61	0	0	1	298,783	82,522,236
Nov-07	85,256,947	463	-	30	139.84	0	0	0	287,645	85,831,981
Dec-07	88,503,147	631	-	31	140.07	0	0	0	276,506	90,616,605
Jan-08	91,586,649	624	-	31	139.97	0	0	0	320,358	90,193,253
Feb-08	87,242,239	675	-	29	139.86	0	0	0	364,210	86,883,764
Mar-08	88,370,234	610	-	31	139.76	0	0	0	408,061	89,364,240
Apr-08	79,320,755	254	-	30	139.65	1	0	0	451,913	77,094,174
May-08	77,025,833	194	3	31	139.55	0	1	0	495,765	78,986,787
Jun-08	84,090,015	23	72	30	139.44	0	0	0	539,617	85,043,783
Jul-08	91,739,839	1	111	31	139.34	0	0	0	583,469	90,658,226
Aug-08	85,561,377	13	64	31	139.23	0	0	0	627,320	85,349,286
Sep-08	81,335,600	59	27	30	139.13	0	0	0	671,172	79,754,130
Oct-08	79,888,372	279	-	31	139.02	0	0	1	715,024	79,884,447
Nov-08	81,455,826	452	-	30	138.92	0	0	0	758,876	82,458,211
Dec-08	85,806,592	655	-	31	138.81	0	0	0	802,728	87,299,977

	Total Purchases	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Real Ontario GDP (chained $1997 with Base 100 in 1997)	April	May	October	Negative Impact Variable	Predicted Purchases
Jan-09	90,223,487	830	-	31	138.39	0	0	0	846,775	89,618,972
Feb-09	77,995,973	606	-	28	137.97	0	0	0	890,823	79,835,407
Mar-09	80,993,879	534	-	31	137.54	0	0	0	934,871	83,921,427
Apr-09	72,518,420	306	1	30	137.13	1	0	0	978,918	73,658,163
May-09	72,158,813	159	7	31	136.71	0	1	0	1,022,966	74,348,529
Jun-09	76,645,030	49	34	30	136.29	0	0	0	1,067,013	76,609,059
Jul-09	77,751,228	6	44	31	135.87	0	0	0	1,111,061	78,398,929
Aug-09	84,421,103	10	91	31	135.46	0	0	0	1,155,109	83,197,909
Sep-09	74,688,913	55	21	30	135.05	0	0	0	1,199,156	73,797,677
Oct-09	75,437,058	288	-	31	134.63	0	0	1	1,243,204	74,605,904
Nov-09	75,196,070	361	-	30	134.22	0	0	0	1,287,252	75,420,615
Dec-09	82,800,231	631	-	31	133.81	0	0	0	1,331,299	81,165,011
Jan-10	85,740,318	720	-	31	134.14	0	0	0	1,310,119	82,883,115
Feb-10	76,200,453	598	-	28	134.47	0	0	0	1,288,938	75,515,410
Mar-10	78,025,071	423	-	31	134.81	0	0	0	1,267,758	78,744,609
Apr-10	69,790,834	225	-	30	135.14	1	0	0	1,246,577	69,618,094
May-10	76,066,070	108	46	31	135.47	0	1	0	1,225,396	75,984,399
Jun-10	79,225,718	22	59	30	135.81	0	0	0	1,204,216	77,823,532
Jul-10	89,977,040	2	165	31	136.14	0	0	0	1,183,035	91,441,716
Aug-10	88,856,918	2	139	31	136.48	0	0	0	1,161,855	88,871,068
Sep-10	74,349,622	78	32	30	136.81	0	0	0	1,140,674	76,637,667
Oct-10	73,264,038	242	-	31	137.15	0	0	1	1,119,494	75,956,933
Nov-10	76,397,905	405	-	30	137.49	0	0	0	1,098,313	78,996,925
Dec-10	82,865,127	676	-	31	137.83	0	0	0	1,077,132	85,537,680
Jan-11	86,054,286	775	-	31	138.03	0	0	0	1,137,864	86,885,269
Feb-11	76,331,650	654	-	28	138.24	0	0	0	1,198,596	78,990,333
Mar-11	80,293,454	573	-	31	138.44	0	0	0	1,259,328	83,184,563
Apr-11	71,266,778	332	-	30	138.65	1	0	0	1,320,060	72,837,459
May-11	72,652,306	134	13	31	138.86	0	1	0	1,380,792	73,763,865
Jun-11	76,886,232	19	52	30	139.06	0	0	0	1,441,524	77,495,538
Jul-11	93,432,708	-	199	31	139.27	0	0	0	1,502,256	95,015,881
Aug-11	86,792,643	-	122	31	139.48	0	0	0	1,562,987	86,361,148
Sep-11	75,561,451	48	40	30	139.69	0	0	0	1,623,719	75,882,470
Oct-11	73,210,552	236	2	31	139.89	0	0	1	1,684,451	74,402,408
Nov-11	74,362,595	342	-	30	140.10	0	0	0	1,745,183	75,726,650
Dec-11	78,058,079	534	-	31	140.31	0	0	0	1,805,915	80,466,675
Jan-12	83,475,292	611	-	31	140.50	0	0	0	1,817,663	81,727,489
Feb-12	76,561,560	532	-	29	140.68	0	0	0	1,829,412	76,686,169
Mar-12	76,020,278	349	0	31	140.87	0	0	0	1,841,160	77,646,939
Apr-12	69,885,112	322	-	30	141.05	1	0	0	1,852,908	70,943,797
May-12	77,152,267	81	37	31	141.24	0	1	0	1,864,657	74,081,505
Jun-12	83,683,997	23	102	30	141.43	0	0	0	1,876,405	81,828,730
Jul-12	97,430,291	-	190	31	141.61	0	0	0	1,888,153	93,171,395
Aug-12	90,717,699	2	112	31	141.80	0	0	0	1,899,902	84,629,923
Sep-12	77,862,575	85	36	30	141.99	0	0	0	1,911,650	75,637,943
Oct-12	75,966,062	243	1	31	142.18	0	0	1	1,923,398	74,260,137
Nov-12	77,579,681	434	-	30	142.37	0	0	0	1,935,147	77,351,999
Dec-12	78,044,417	534	-	31	142.55	0	0	0	1,946,895	80,885,879
Jan-13		719	-	31	142.73	0	0	0	1,935,349	84,013,819
Feb-13		636	-	28	142.91	0	0	0	1,923,802	77,116,200
Mar-13		523	0	31	143.09	0	0	0	1,912,255	81,209,097
Apr-13		310	0	30	143.26	1	0	0	1,900,708	71,735,837
May-13		148	16	31	143.44	0	1	0	1,889,162	73,950,770
Jun-13		27	72	30	143.62	0	0	0	1,877,615	79,836,227
Jul-13		2	138	31	143.80	0	0	0	1,866,068	88,716,036
Aug-13		5	110	31	143.98	0	0	0	1,854,522	85,889,548
Sep-13		55	33	30	144.16	0	0	0	1,842,975	76,477,655
Oct-13		243	3	31	144.33	0	0	1	1,831,428	76,232,907
Nov-13		400	-	30	144.51	0	0	0	1,819,882	78,654,469
Dec-13		603	-	31	144.69	0	0	0	1,808,335	83,962,411

	Total Purchases	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Real Ontario GDP (chained $1997 with Base 100 in 1997)	April	May	October	Negative Impact Variable	Predicted Purchases
Jan-03	87,388,286	815	-	31	125.66	0	0	0	0	87,217,802
Feb-03	79,249,838	699	-	28	125.81	0	0	0	0	79,726,415
Mar-03	81,540,901	581	-	31	125.95	0	0	0	0	83,652,077
Apr-03	74,201,337	373	2	30	126.10	1	0	0	0	74,393,099
May-03	72,603,730	178	-	31	126.24	0	1	0	0	73,991,138
Jun-03	77,278,956	43	53	30	126.39	0	0	0	0	79,239,113
Jul-03	90,974,807	0	118	31	126.54	0	0	0	0	87,757,646
Aug-03	81,817,315	2	128	31	126.68	0	0	0	0	88,937,545
Sep-03	78,164,432	55	24	30	126.83	0	0	0	0	76,474,474
Oct-03	78,072,590	276	-	31	126.98	0	0	1	0	77,315,494
Nov-03	79,241,459	399	-	30	127.12	0	0	0	0	79,471,924
Dec-03	83,752,558	562	-	31	127.27	0	0	0	0	84,064,018
Jan-04	90,837,491	849	-	31	127.53	0	0	0	0	88,798,917
Feb-04	83,093,877	632	-	29	127.80	0	0	0	0	81,654,360
Mar-04	85,032,643	487	-	31	128.06	0	0	0	0	83,312,246
Apr-04	76,314,845	332	-	30	128.32	1	0	0	0	74,695,878
May-04	76,988,030	159	9	31	128.59	0	1	0	0	75,924,087
Jun-04	80,201,463	44	32	30	128.85	0	0	0	0	78,253,009
Jul-04	84,364,755	4	86	31	129.12	0	0	0	0	85,708,355
Aug-04	83,757,950	13	60	31	129.38	0	0	0	0	83,043,202
Sep-04	81,122,721	30	41	30	129.65	0	0	0	0	79,523,988
Oct-04	78,913,063	226	2	31	129.92	0	0	1	0	78,302,148
Nov-04	81,423,641	379	-	30	130.19	0	0	0	0	80,842,805
Dec-04	87,558,513	643	-	31	130.45	0	0	0	0	87,118,272
Jan-05	91,714,412	770	-	31	130.74	0	0	0	0	89,298,381
Feb-05	81,076,815	616	-	28	131.03	0	0	0	0	81,278,369
Mar-05	87,176,799	609	-	31	131.33	0	0	0	0	87,041,389
Apr-05	75,263,673	307	-	30	131.62	1	0	0	0	76,109,849
May-05	78,470,578	189	1	31	131.91	0	1	0	0	77,373,785
Jun-05	92,848,969	9	146	30	132.20	0	0	0	0	92,188,745
Jul-05	94,845,399	-	189	31	132.50	0	0	0	0	98,797,081
Aug-05	93,143,275	0	141	31	132.79	0	0	0	0	93,663,988
Sep-05	80,842,300	23	52	30	133.09	0	0	0	0	82,495,222
Oct-05	79,268,420	220	8	31	133.38	0	0	1	0	80,780,118
Nov-05	82,590,728	388	-	30	133.68	0	0	0	0	82,909,161
Dec-05	88,412,660	665	-	31	133.98	0	0	0	0	89,401,660
Jan-06	88,782,670	552	-	31	134.25	0	0	0	34,181	87,546,113
Feb-06	82,652,726	604	-	28	134.53	0	0	0	68,362	82,613,107
Mar-06	87,287,263	517	-	31	134.81	0	0	0	102,543	86,897,664
Apr-06	76,130,011	293	-	30	135.08	1	0	0	136,723	77,016,164
May-06	81,448,519	137	26	31	135.36	0	1	0	170,904	80,235,875
Jun-06	86,666,222	20	74	30	135.64	0	0	0	205,085	85,049,309
Jul-06	96,205,464	-	167	31	135.92	0	0	0	239,266	96,947,457
Aug-06	91,965,539	4	102	31	136.20	0	0	0	273,447	89,721,362
Sep-06	78,075,371	81	13	30	136.48	0	0	0	307,628	79,205,081
Oct-06	81,808,423	288	1	31	136.76	0	0	1	341,808	81,052,342
Nov-06	83,973,333	382	-	30	137.04	0	0	0	375,989	82,509,408
Dec-06	87,799,550	501	-	31	137.33	0	0	0	410,170	86,266,771
Jan-07	92,807,711	647	-	31	137.55	0	0	0	399,031	88,795,102
Feb-07	87,369,732	740	-	28	137.78	0	0	0	387,893	84,740,386
Mar-07	89,810,436	547	-	31	138.01	0	0	0	376,754	87,569,330
Apr-07	80,121,095	356	-	30	138.23	1	0	0	365,615	78,446,183
May-07	80,608,589	136	22	31	138.46	0	1	0	354,477	80,484,764
Jun-07	89,502,716	17	99	30	138.69	0	0	0	343,338	88,712,580
Jul-07	89,014,824	3	106	31	138.92	0	0	0	332,199	91,360,455
Aug-07	94,084,356	5	141	31	139.15	0	0	0	321,061	95,434,042
Sep-07	82,681,855	37	48	30	139.38	0	0	0	309,922	83,900,662
Oct-07	83,253,588	138	20	31	139.61	0	0	1	298,783	82,522,236
Nov-07	85,256,947	463	-	30	139.84	0	0	0	287,645	85,831,981
Dec-07	88,503,147	631	-	31	140.07	0	0	0	276,506	90,616,605
Jan-08	91,586,649	624	-	31	139.97	0	0	0	320,358	90,193,253
Feb-08	87,242,239	675	-	29	139.86	0	0	0	364,210	86,883,764
Mar-08	88,370,234	610	-	31	139.76	0	0	0	408,061	89,364,240
Apr-08	79,320,755	254	-	30	139.65	1	0	0	451,913	77,094,174
May-08	77,025,833	194	3	31	139.55	0	1	0	495,765	78,986,787
Jun-08	84,090,015	23	72	30	139.44	0	0	0	539,617	85,043,783
Jul-08	91,739,839	1	111	31	139.34	0	0	0	583,469	90,658,226
Aug-08	85,561,377	13	64	31	139.23	0	0	0	627,320	85,349,286
Sep-08	81,335,600	59	27	30	139.13	0	0	0	671,172	79,754,130
Oct-08	79,888,372	279	-	31	139.02	0	0	1	715,024	79,884,447
Nov-08	81,455,826	452	-	30	138.92	0	0	0	758,876	82,458,211
Dec-08	85,806,592	655	-	31	138.81	0	0	0	802,728	87,299,977

	Total Purchases	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Real Ontario GDP (chained $1997 with Base 100 in 1997)	April	May	October	Negative Impact Variable	Predicted Purchases
Jan-09	90,223,487	830	-	31	138.39	0	0	0	846,775	89,618,972
Feb-09	77,995,973	606	-	28	137.97	0	0	0	890,823	79,835,407
Mar-09	80,993,879	534	-	31	137.54	0	0	0	934,871	83,921,427
Apr-09	72,518,420	306	1	30	137.13	1	0	0	978,918	73,658,163
May-09	72,158,813	159	7	31	136.71	0	1	0	1,022,966	74,348,529
Jun-09	76,645,030	49	34	30	136.29	0	0	0	1,067,013	76,609,059
Jul-09	77,751,228	6	44	31	135.87	0	0	0	1,111,061	78,398,929
Aug-09	84,421,103	10	91	31	135.46	0	0	0	1,155,109	83,197,909
Sep-09	74,688,913	55	21	30	135.05	0	0	0	1,199,156	73,797,677
Oct-09	75,437,058	288	-	31	134.63	0	0	1	1,243,204	74,605,904
Nov-09	75,196,070	361	-	30	134.22	0	0	0	1,287,252	75,420,615
Dec-09	82,800,231	631	-	31	133.81	0	0	0	1,331,299	81,165,011
Jan-10	85,740,318	720	-	31	134.14	0	0	0	1,310,119	82,883,115
Feb-10	76,200,453	598	-	28	134.47	0	0	0	1,288,938	75,515,410
Mar-10	78,025,071	423	-	31	134.81	0	0	0	1,267,758	78,744,609
Apr-10	69,790,834	225	-	30	135.14	1	0	0	1,246,577	69,618,094
May-10	76,066,070	108	46	31	135.47	0	1	0	1,225,396	75,984,399
Jun-10	79,225,718	22	59	30	135.81	0	0	0	1,204,216	77,823,532
Jul-10	89,977,040	2	165	31	136.14	0	0	0	1,183,035	91,441,716
Aug-10	88,856,918	2	139	31	136.48	0	0	0	1,161,855	88,871,068
Sep-10	74,349,622	78	32	30	136.81	0	0	0	1,140,674	76,637,667
Oct-10	73,264,038	242	-	31	137.15	0	0	1	1,119,494	75,956,933
Nov-10	76,397,905	405	-	30	137.49	0	0	0	1,098,313	78,996,925
Dec-10	82,865,127	676	-	31	137.83	0	0	0	1,077,132	85,537,680
Jan-11	86,054,286	775	-	31	138.03	0	0	0	1,137,864	86,885,269
Feb-11	76,331,650	654	-	28	138.24	0	0	0	1,198,596	78,990,333
Mar-11	80,293,454	573	-	31	138.44	0	0	0	1,259,328	83,184,563
Apr-11	71,266,778	332	-	30	138.65	1	0	0	1,320,060	72,837,459
May-11	72,652,306	134	13	31	138.86	0	1	0	1,380,792	73,763,865
Jun-11	76,886,232	19	52	30	139.06	0	0	0	1,441,524	77,495,538
Jul-11	93,432,708	-	199	31	139.27	0	0	0	1,502,256	95,015,881
Aug-11	86,792,643	-	122	31	139.48	0	0	0	1,562,987	86,361,148
Sep-11	75,561,451	48	40	30	139.69	0	0	0	1,623,719	75,882,470
Oct-11	73,210,552	236	2	31	139.89	0	0	1	1,684,451	74,402,408
Nov-11	74,362,595	342	-	30	140.10	0	0	0	1,745,183	75,726,650
Dec-11	78,058,079	534	-	31	140.31	0	0	0	1,805,915	80,466,675
Jan-12	83,475,292	611	-	31	140.50	0	0	0	1,817,663	81,727,489
Feb-12	76,561,560	532	-	29	140.68	0	0	0	1,829,412	76,686,169
Mar-12	76,020,278	349	0	31	140.87	0	0	0	1,841,160	77,646,939
Apr-12	69,885,112	322	-	30	141.05	1	0	0	1,852,908	70,943,797
May-12	77,152,267	81	37	31	141.24	0	1	0	1,864,657	74,081,505
Jun-12	83,683,997	23	102	30	141.43	0	0	0	1,876,405	81,828,730
Jul-12	97,430,291	-	190	31	141.61	0	0	0	1,888,153	93,171,395
Aug-12	90,717,699	2	112	31	141.80	0	0	0	1,899,902	84,629,923
Sep-12	77,862,575	85	36	30	141.99	0	0	0	1,911,650	75,637,943
Oct-12	75,966,062	243	1	31	142.18	0	0	1	1,923,398	74,260,137
Nov-12	77,579,681	434	-	30	142.37	0	0	0	1,935,147	77,351,999
Dec-12	78,044,417	534	-	31	142.55	0	0	0	1,946,895	80,885,879
Jan-13		719	-	31	142.73	0	0	0	1,935,349	84,013,819
Feb-13		636	-	28	142.91	0	0	0	1,923,802	77,116,200
Mar-13		523	0	31	143.09	0	0	0	1,912,255	81,209,097
Apr-13		310	0	30	143.26	1	0	0	1,900,708	71,735,837
May-13		148	16	31	143.44	0	1	0	1,889,162	73,950,770
Jun-13		27	72	30	143.62	0	0	0	1,877,615	79,836,227
Jul-13		2	138	31	143.80	0	0	0	1,866,068	88,716,036
Aug-13		5	110	31	143.98	0	0	0	1,854,522	85,889,548
Sep-13		55	33	30	144.16	0	0	0	1,842,975	76,477,655
Oct-13		243	3	31	144.33	0	0	1	1,831,428	76,232,907
Nov-13		400	-	30	144.51	0	0	0	1,819,882	78,654,469
Dec-13		603	-	31	144.69	0	0	0	1,808,335	83,962,411

OPERATING REVENUE VARIANCE ANALYSIS

Variance Analysis on Throughput Revenue:

A summary of historical and forecast operating revenues is presented in Table 3.0. A variance analysis for the other net operating revenue will be provided further in Tab 3 Schedule 2 of this Exhibit.

2008 Board Approved:

BPI's Board Approved forecast operating revenue in 2008 was $16,879,874. Throughput revenue was $15,457,545, or 91.6% of total revenues. Other net operating revenue accounts for the remaining $1,422,329. The 2008 Board Approved throughput revenue includes SSS Admin Fees. From 2008 Actual to 2013 Test Year, SSS Admin fees are separated from Distribution Revenue, and included in Other Revenue.

2008 Actual:

BPI's operating revenue in fiscal 2008 was $16,492,164. Throughput revenue was $14,981,818 or 90.8% of total revenues. Other net operating revenue accounts for the remaining $1,510,346.

Table 3.22: Throughput Revenue Comparison 2008 Board Approved to 2008 Actual

	2008 Board Approv	2008 Actual	$ Variance	% Variance
Residential	$ 8,408,128	$ 8,446,939	$ 38,811	0.5%
Less Than	$ 1,450,724	$ 1,461,018	$ 10,294	0.7%
Greater Than	$ 5,359,345	$ 4,550,787	$ (808,558)	-15.1%
Unmetered	$ 78,499	$ 82,582	$ 4,083	5.2%
street	$ 101,753	$ 76,194	$ (25,559)	-25.1%
sentinel	$ 21,416	$ 7,633	$ (13,783)	-64.4%
embedded		$ 295,547	$ 295,547	
standby	$ 37,679	$ 61,118	$ 23,439	62.2%
Subtotal	$ 15,457,544	$ 14,981,818	$ (475,726)	-3.1%

Comparison to 2008 Board Approved

Throughput revenue for 2008 actual was (3.1%) or ($475,726) lower than the amounts approved in the 2008 EDR primarily due to lower than forecast consumption in most customer classes, as well as lower than forecast customer/connections in most classes.

The inclusion of the SSS admin fees in the 2008 Board Approved amount complicates the analysis, as 2008 Actual amounts exclude SSS admin fees. Adding the 2008 Actual SSS Admin Fees of $93,320 into the distribution revenue, the variance becomes ($382,406) or (2.5%).

The greatest variance from forecast comes from the GS>50 kW class. In this class there are two factors causing the decrease. First, the actual amount of kW billed for this class was much lower than forecast. Secondly, the revenue forecast for this class assumed that 2008 rates would be in place for most of 2008. In reality, 2008 rates came into place only on September 1 2008. The majority of the 2008 year was billed on 2007 rates. The greatest increase was seen in the GS > 50 kW class. This was caused by the volumetric rate increase in this class between 2007 and 2008 rates.

Revenues from the Sentinel Light and Street Lighting classes increased as a result of rate increases from the EB-2007-0698 case.

Table 3.23 below compares the 2008 EDR Approved billing quantities to the 2008 Actual quantities.

Table 3.23: 2008 Board Approved to 2008 Actual Billing Quantity Variance

	Customers		Energy (kWh or kW)			Variance	
Class	**2008 BA**	**2008 Actual**	**2008 BA**	**2008 Actual**	**Billing Determinant**	**Customer Variance**	**Energy Variance**
Residential	33,818	33,645	294,990,955	278,923,645	kWh	(173)	(16,067,310)
GS<50	2,675	2,707	110,476,190	104,110,563	kWh	32	(6,365,627)
GS>50	413	405	1,635,606	1,477,384	kW	(8)	(158,222)
Streetlight	10,056	7,540	25,242	22,064	kW	(2,517)	(3,178)
USL	435	440	2,335,344	1,681,733	kWh	5	(653,611)
Sentinel	788	586	1,787		kW	(202)	(1,787)
Standby	1	1		36,000	kW*	-	36,000
Embedded	1	1		106,971.98	kW	-	106,972

**kW in the Standby class represents kW of reserved capacity, rather than kW of load as in the other classes.*

2009 Actual:

BPI's operating revenue in fiscal 2009 was $16,169,057 as shown in Exhibit 3, Tab 1, Table 3.0. Throughput revenue totaled $14,693,827 or 90.9% of total revenues. Other net operating revenue accounts for the remaining revenue of $1,475,230.

Comparison 2008 to 2009 Actual – Throughput Revenue*:*

Table 3.24: Throughput Revenue Comparison 2008 Actual to 2009 Actual

	2008	2009	$ Variance	% Variance
Residential	$ 8,446,939	$ 8,217,209	$ (229,730)	-2.7%
Less Than	$ 1,461,018	$ 1,398,432	$ (62,587)	-4.3%
Greater Than	$ 4,550,787	$ 4,516,486	$ (34,301)	-0.8%
Unmetered	$ 82,582	$ 80,094	$ (2,488)	-3.0%
street	$ 76,194	$ 113,929	$ 37,735	49.5%
sentinel	$ 7,633	$ 20,541	$ 12,908	169.1%
embedded	$ 295,547	$ 287,637	$ (7,910)	-2.7%
standby	$ 61,118	$ 59,499	$ (1,619)	-2.6%
Subtotal	$ 14,981,818	$ 14,693,827	$ (287,991)	-1.9%

The 2009 throughput revenue was ($287,991) or (1.9%) lower than the 2008 actual revenue.

The amounts of kWh and kW billed in 2009 compared to 2008 decreased, causing much of the revenue decrease. Street lights and Sentinel lights were the only classes which saw revenue increases. This was due in part to the higher rates resulting from BPI's 2009 IRM application, in which the revenue-to–cost ratios for these classes were shifted closer to the low end of the Board's target range of revenue-to-cost ratios for these classes. Table 3.25 below compares the 2008 Actual billing quantities to the 2009 Actual quantities.

Table 3.25: 2008 Actual to 2009 Billing Quantity Variance

	Customers		Energy (kWh or kW)			Variance	
Class	**2008 AC**	**2,009**	**2008 AC**	**2,009**	**Billing Determinant**	**Customer Variance**	**Energy Variance**
Residential	33,645	33,929	278,923,645	275,417,341	kWh	285	(3,506,304)
GS<50	2,707	2,700	104,110,563	99,603,717	kWh	(7)	(4,506,846)
GS>50	405	409	1,477,384	1,336,469	kW	4	(140,915)
Streetlight	7,540	9,577	22,064	22,380	kW	2,037	316
USL	440	444	1,681,733	1,552,460	kWh	4	(129,273)
Sentinel	7,540	9,577	-	-	kW	2,037	
Standby	1	1	36,000	36,000	kW*	-	-
Embedded	1	1	106,972	155,883.47	kW	-	48,911

2010 Actual:

BPI's operating revenue in fiscal 2010 was $16,544,331, as shown in Exhibit 3, Tab 1, Table 3.0. Throughput revenue totaled $15,193,777 or 91.8% of total revenues. Other net operating revenue accounts for the remaining revenue of $1,350,554.

Comparison 2009 Actual to 2010 Actual Throughput Revenue:

Table 3.26: Throughput Revenue Comparison 2009 to 2010 Actual

	2009	2010	$ Variance	% Variance
Residential	$ 8,217,209	$ 8,549,417	$ 332,207	4.0%
Less Than	$ 1,398,432	$ 1,411,955	$ 13,524	1.0%
Greater Than	$ 4,516,486	$ 4,367,983	$ (148,504)	-3.3%
Unmetered	$ 80,094	$ 80,298	$ 204	0.3%
street	$ 113,929	$ 130,347	$ 16,418	14.4%
sentinel	$ 20,541	$ 26,502	$ 5,961	29.0%
embedded	$ 287,637	$ 564,797	$ 277,161	96.4%
standby	$ 59,499	$ 62,478	$ 2,979	5.0%
Subtotal	$ 14,693,827	$ 15,193,777	$ 499,949	3.4%

Throughput revenue in 2010 was 3.4% or $499,949 higher than in 2009 due to a combination of increased customer and volume in the residential class and the 2010 IRM rate changes effective May 1, 2010. There were volumetric rate increases in the Residential, GS<50 kW, Sentinel and Street Light classes. The Embedded Distributor revenues increased as the 2009 figure included a downward accounting adjustment from this rate class, reducing the 2009 revenues by the equivalent of four months of 2008 revenues. This reduction represented the months between May and September 2008, when BPI charged its Embedded Distributor at its 2007 rates for the GS>50 class. In September 2008, BPI's 2008 rates came into effect. In 2010 this accounting reduction was reversed (the four months of 2008 revenues were added in for 2010) as a result of the Board's Decision in EB-2010-0908, causing an increase in revenues from this class for 2010 compared to the reduced revenues of 2009. Additionally, there was a further increase caused by an increase in kW billed to the Embedded Distributor class between 2009 and 2010

Table 3.27 below compares the 2009 Actual billing quantities to the 2010 Actual quantities.

Table 3.27: 2009 to 2010 Billing Quantity Variance

	Customers		Energy (kWh or kW)			Variance	
Class	**2,009**	**2,010**	**2,009**	**2,010**	**Billing Determinant**	**Customer Variance**	**Energy Variance**
Residential	33,929	34,219	275,417,341	287,357,342	kWh	290	11,940,001
GS<50	2,700	2,684	99,603,717	98,691,975	kWh	(16)	(911,742)
GS>50	409	418	1,336,469	1,325,334	kW	9	(11,135)
Streetlight	9,577	9,644	22,380	22,480	kW	67	100
USL	444	445	1,552,460	1,559,632	kWh	1	7,172
Sentinel	9,577	9,644	-	-	kW	67	
Standby	1	1	36,000	37,716	kW*	-	1,716
Embedded	1	1	155,883	157,644.63	kW	-	1,761

2011 Actual:

BPI's operating revenue in fiscal 2011 was $16,259,794, as shown in Exhibit 3, Tab 1, Table 3.0. Throughput revenue totaled $15,095,015 or 92.8% of total revenues. Other net operating revenue accounted for the remaining revenue of $1,167,779.

Table 3.28: Throughput Revenue Comparison 2010 Actual to 2011 Actual:

	2010	2011	$ Variance	% Variance
Residential	$ 8,549,417	$ 8,636,477	$ 87,060	1.0%
Less Than	$ 1,411,955	$ 1,419,811	$ 7,856	0.6%
Greater Than	$ 4,367,983	$ 4,337,736	$ (30,247)	-0.7%
Unmetered	$ 80,298	$ 79,528	$ (770)	-1.0%
street	$ 130,347	$ 135,989	$ 5,642	4.3%
sentinel	$ 26,502	$ 28,264	$ 1,762	6.6%
embedded	$ 564,797	$ 387,661	$ (177,136)	-31.4%
standby	$ 62,478	$ 66,547	$ 4,069	6.5%
Subtotal	$ 15,193,777	$ 15,092,015	$ (101,762)	-0.7%

Total throughput in 2011 revenue was (0.7) % or ($101,762) lower than in 2010.

The class with the largest decrease in revenue is embedded distributor class. This is due to the upward accounting adjustment to the embedded distribution revenue in 2010 which is discussed above. The decrease from 2010 to 2011 is caused in part by reduced kW used in the Embedded Distributor class, but primarily from the presence of this upward accounting adjustment in 2010, compared to relatively normal distribution revenues in 2011.

Table 3.29: 2010 to 2011 Billing Quantity Variance

	Customers		Energy (kWh or kW)			Variance	
Class	2,010	2,011	2,010	2,011	Billing Determinant	Customer Variance	Energy Variance
Residential	34,219	34,621	287,357,342	289,048,493	kWh	402	1,691,151
GS<50	2,684	2,705	98,691,975	98,344,763	kWh	22	(347,212)
GS>50	418	421	1,325,334	1,343,794	kW	3	18,460
Streetlight	9,644	9,981	22,480	24,297	kW	337	1,817
USL	445	444	1,559,632	1,555,451	kWh	(1)	(4,181)
Sentinel	605	620	1,470	1,423	kW	15	(46)
Standby	1	1	37,716	40,160	kW*	-	2,444
Embedded	1	1	157,645	156,604.95	kW	-	(1,040)

2012 Bridge Year:

BPI's 2012 Test Year operating revenue is forecast to be $16,260,626 as shown in Exhibit 3, Tab 1, Table 3.0. Throughput revenue totals $15,190,508 or 93.4% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $1,070,118.

Comparison of 2012 Bridge Year to 2011 Actual Throughput Revenue:

Table 3.30: Throughput Revenue Comparison 2011 Actual to 2012 Bridge

	2011	2012	$ Variance	% Variance
Residential	$ 8,636,477	$ 8,599,371	$ (37,106)	-0.4%
Less Than	$ 1,419,811	$ 1,437,538	$ 17,727	1.2%
Greater Than	$ 4,337,736	$ 4,442,452	$ 104,716	2.4%
Unmetered	$ 79,528	$ 74,600	$ (4,928)	-6.2%
street	$ 135,989	$ 136,856	$ 867	0.6%
sentinel	$ 28,264	$ 32,255	$ 3,991	14.1%
embedded	$ 387,661	$ 402,904	$ 15,243	3.9%
standby	$ 66,547	$ 64,532	$ (2,015)	-3.0%
Subtotal	$ 15,092,015	$ 15,190,508	$ 98,493	0.7%

Throughput revenue in 2012 is forecast to be only an increase of 0.7% or $98,493 from 2011 actual. This is a result of the rate increases from the 2012 IRM case, as well as changes in billing quantities. Table 3.31 below compares the 2011 Actual billing quantities to the 2012 actual billing quantities. The increase is driven by increased revenues from the GS>50 kW class, due to a higher volumetric rate in that class combined with higher kW.

Table 3.31: 2011 Actual to 2012 Actual Billing Quantity Variance

	Customers		Energy (kWh or kW)			Variance	
Class	**2,011**	**2,012**	**2,011**	**2,012**	**Billing Determinant**	**Customer Variance**	**Energy Variance**
Residential	34,621	34,913	289,048,493	284,844,991	kWh	292	(4,203,502)
GS<50	2,705	2,729	98,344,763	99,625,182	kWh	24	1,280,419
GS>50	421	417	1,343,794	1,386,954	kW	(4)	43,160
Streetlight	9,981	10,145	24,297	22,533	kW	164	(1,764)
USL	444	443	1,555,451	1,535,988	kWh	(1)	(19,463)
Sentinel	620	624	1,423	1,331	kW	4	(92)
Standby	1	1	40,160	38,712	kW*	-	(1,448)
Embedded	1	1	156,605	153,167.54	kW	-	(3,437)

2013 Test Year:

Table 3.32: Throughput Revenue Comparison 2012 Bridge to 2013 Test

Distribution Rev	2012 Bridge	2013 test at propos	$ Variance	% Variance
Residential	$ 8,599,371	$ 9,545,328	$ 945,957	11.0%
GS<50	$ 1,437,538	$ 1,592,778	$ 155,240	10.8%
GS>50	$ 4,442,452	$ 4,983,913	$ 541,461	12.2%
Streetlight	$ 136,856	$ 157,703	$ 20,847	15.2%
USL	$ 74,600	$ 80,547	$ 5,947	8.0%
Embedded Distr	$ 402,904	$ 282,689	$ (120,215)	-29.8%
Standby**	$ 64,532		$ (64,532)	-100.0%
Sentinel	$ 32,255	$ 60,496	$ 28,241	87.6%
	$ 15,190,508	$ 16,703,454	$ 1,512,946	10.0%

Total throughput revenue in 2013 test is forecast to be $1,512,946 or 10.0% higher than in 2012 bridge. This is a result of the expected changes in rates resulting from this Application. Revenues from Standby rates have been included as a revenue offset, rather than throughput revenue in the 2013 forecast for this Application.

Below, Table 3.33 compares 2013 revenues at current rates with 2013 revenues at the rates proposed in this Application.

Table 3.33: 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**

1 Table 3.34 below compares the 2012 Actual billing quantities to the 2013 Test billing quantities.

2 **Table 3.34: 2012 Bridge to 2013 Test Billing Quantity Variance**

	Customers		Energy (kWh or kW)			Variance	
Class	**2,012**	**2013 Test**	**2,012**	**2013 Test**	**Billing Determinant**	**Customer Variance**	**Energy Variance**
Residential	34,913	35,364	284,844,991	280,913,502	kWh	451	(3,931,489)
GS<50	2,729	2,764	99,625,182	97,535,297	kWh	35	(2,089,885)
GS>50	417	420	1,386,954	1,354,270	kW	3	(32,684)
Streetlight	10,145	10,355	22,533	23,455	kW	210	922
USL	443	437	1,535,988	1,454,727	kWh	(6)	(81,261)
Sentinel	624	635	1,331	1,356	kW	11	25
Standby	1	1	38,712	36,000	kW*	-	(2,712)
Embedded	1	1	153,168	155,805.71	kW	-	2,638

TRANSFORMER ALLOWANCE

BPI currently provides a Transformer Ownership Allowance Credit of $0.60 /kW to those customers that own their own transformer facilities. BPI is proposing to maintain this rate for the 2013 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE

Preamble:

The Materiality threshold used to analyze Other Distribution Revenue was the threshold used for OM&A costs, as calculated below:

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

To allow for the most detailed review of materiality on Other Distribution Revenue, BPI has selected a low materiality threshold of $70,000. BPI has provided explanations for the following variances, which exceed the materiality threshold:

2008 Board Approved to 2008 Actual

Account	2008 Board Approved	2008 Actual	Variance
4235. Miscellaneous Service Revenues	$ 679,232	$ 589,631	$ (89,601)

The 2007 and 2008 forecasts for Miscellaneous Service Revenues in the 2008 EDR application included an increase over the usual level of Miscellaneous Revenues. This increase was included in order to reflect a planned change in business practice, specifically to the collection of accounts specific service charge. In 2008 Actual, revenues did increase as a result of this change, but not to the full extent predicted in the rate application.

Account	2008 Board Approved	2008 Actual	Variance
4375-Revenue from Non-Utility Operations	$0	$ 541,188	$ 541,188

In its 2008 EDR Board-Approved application, BPI did not forecast any revenues from non-utility operations. Expected revenue in 4375 would have been mainly from OPA CDM programs. As explained in BPI's 2008 EDR application, at the time of the application, the 2008 OPA CDM suite of programs had not yet been released. As a result, BPI did not include any forecasted revenues from non-utility operations

The $541,188 represents mainly OPA CDM revenues, as well as a bonus from the OPA for CDM performance, and $161,356 in Street Light maintenance revenue.

Account	2008 Board Approved	2008 Actual	Variance
4380-Expenses from Non-Utility Operations	$0	$ (482,836)	$ (482,836)

In its 2008 EDR Board-Approved application, BPI did not forecast any expenses from non-utility operations. as with Account 4375, expected expenses in Account 4380 would have been associated mainly with OPA CDM programs. At the time of the application, the 2008 OPA CDM suite of programs had not yet been released. As a result, BPI did not include any forecasted expenses from non-utility operations.

The 2008 Actual amount of $482,836 represents primarily OPA CDM expenses, as well as $161,356 of expenses for street light maintenance.

Account	2008 Board Approved	2008 Actual	Variance
4390- Miscellaneous Non-Operating Income	$0	$ 70,259	$ 70,259

For its 2008 Board-Approved application, BPI did not forecast any revenues in 4390. 2008 Actual revenues included $70,259, primarily from sales of scrap metal.

2008 Actual to 2009 Actual

Account	2008 Actual	2009 Actual	Variance
4405- Interest & Dividend Income	$385,736	$128,823	$(256,913)

The decrease in Interest and Dividend Income between 2008 and 2009 actuals is a result of the drop in bank account interest rates between the two years.

2009 Actual to 2010 Actual

Account	2009 Actual	2010 Actual	Variance
4225- Late Payment Charges	$ 99,278	$ 7,651	(91,628)

The decrease in Late Payment Charges between 2009 and 2010 is due to the removal from this account of $126,681 for the accrual of the late payment lawsuit settlement in 2010. Late payment charges increased somewhat between 2009 and 2010, offsetting some of the effect of the settlement of the late payment lawsuit.

Account	2009 Actual	2010 Actual	Variance
4355-Gain on Disposition of Utility and Other Property	$(22,969)	$51,067	$74,035

The increase between 2009 and 2010 can be explained through increased dispositions in the year 2010. The largest disposition in 2010 was the sale of 67A Barnes Ave, the site of a decommissioned distribution station. Other dispositions included the sale of one vehicle and the trade-in value of another also contributing to the increase.

Account	2009 Actual	2010 Actual	Variance
4375-Revenue from Non-Utility Operations	$2,189,506	$1,130,495	$(1,059,011)

The decrease in Revenue from Non-Utility Operations between 2009 and 2010 actual can be attributed to the level of OPA CDM activity undertaken in 2010. Additionally, beginning in 2010, BPI changed its accounting practices in regards to the treatment of street light maintenance revenues and expenses. In 2010, no revenues from street light maintenance were recorded in account 4375.

Account	**2009 Actual**	**2010 Actual**	**Variance**
4380-Expenses from Non-Utility Operations	$(1,846,309)	$(926,976)	$ 919,333

The decrease in Expenses from Non-Utility Operations between 2009 and 2010 actual can be attributed to the level of OPA CDM activity undertaken in 2010. Additionally beginning in 2010, BPI changed its accounting practices in regard to the treatment of street light maintenance revenues and expenses. In 2010, no expenses from street light maintenance were recorded in account 4380.

2010 Actual to 2011 Actual

Account	**2010 Actual**	**2011 Actual**	**Variance**
4225- Late Payment Charges	$7,651	$111,988	$104,337

The apparent increase in Late Payment Charges between 2010 and 2011 is due to removal from this account of $126 681.66 for the accrual of the late payment lawsuit settlement in 2010. There was a decrease in late payment charges between 2010 and 2011, offsetting some of the effect of the late payment lawsuit settlement.

Account	**2010 Actual**	**2011 Actual**	**Variance**
4235- Miscellaneous Service Revenue	$ 635,867	$469,500	$(166,367)

The drop in miscellaneous service revenue between 2010 and 2011 actual is mainly due to a drop in revenues from the collection of account specific service charge. Starting in January 2011, a reduction occurred in the amount of field collection charges levied as a result of the Board's new customer service rules, requiring BPI to apply customer deposits against an account in arrears prior to attempting a collection of account.

Account	**2010 Actual**	**2011 Actual**	**Variance**
4375-Revenue from Non-Utility Operations	$1,130,495	$723,014	$(407,481)

A difference in the levels of OPA CDM revenues explains the reduction in Revenue from Non-Utility Operations from 2010 to 2011.

Account	**2010 Actual**	**2011 Actual**	**Variance**
4380-Expenses from Non-Utility Operations	$(926,976)	$(735,093)	$191,883

A difference in the levels of OPA CDM expenses explains the reduction in Revenue from Non-Utility Operations from 2010 to 2011.

Account	**2010 Actual**	**2011 Actual**	**Variance**
4405-Interest & Dividend Income	$129,666	$278,195	$148,529

The increase in Account 4405- Interest and Dividend income between 2010 and 2011 was caused by an increase in BPI's bank account balance which in turn increased bank account interest received in 2011. The increase was due to a lump sum payment from BPI's embedded distributor for historic retail transmission charges owed to BPI.

2011 Actual to 2012 Bridge Forecast

Account	**2011 Actual**	**2012 Bridge**	**Variance**
4375- Revenue from Non-Utility Operations	$723,014	$3,897,395	$3,174,381

This increase between 2011 actual and 2012 forecast bridge Revenue from Non-Utility Operations is due to an increase in the expected level of OPA CDM revenues, including bonus.

Account	2011 Actual	2012 Bridge	Variance
4380- Expenses from Non-Utility Operations	$(735,093)	$(3,897,395)	$3,162,302

This increase between 2011 actual and forecasted 2012 Bridge Expenses from Non-Utility Operations is due to an increase in the expected level of OPA CDM expenses, including bonus**.**

2012 Bridge to 2013 Test Forecast

Account	2012 Bridge	2013 Test	Variance
4375-Revenue from Non-Utility Operations	$3,897,395	$5,165,361	$1,267,966

This increase between 2011 actual and forecast 2012 Bridge Revenue from Non-Utility Operations is due to an increase in the expected level of OPA CDM revenues, including bonus.

Account	2012 Bridge	2013 Test	Variance
4380-Expenses from Non-Utility Operations	$(3,897,395)	$(5,165,361)	$1,267,966

This increase between 2011 actual and forecast 2012 Bridge Expenses from Non-Utility Operations is due to an increase in the expected level of OPA CDM expenses, including bonus**.**

Revenue from Affiliate Transactions:

BPI notes its accounting treatment for Street and Sentinel Light maintenance is to record on the balance sheet the expenses and revenues which are related to these services. The expenses and revenues from performing these services net to zero. Due to this accounting treatment, there are no revenues from Street and Sentinel Light maintenance included as revenue offsets for the Test Year. There are also no expenses related to these activities in BPI's Revenue Requirement.

SPECIFIC SERVICE CHARGES:

In preparation for this Application, BPI undertook an internal review in 2011 of its specific services charges and billable work order practices.

That review established the following general principles with respect to specific service charges and billable work orders:

1. Specific service charges and/or billable work orders should be applied when:
   - The activities performed are not standard level of distribution services as defined by the Distribution System Code and BPI's Conditions of Service; and
   - The costs related to the activities should be borne by those customers causing the costs and should not be allocated to all customers.

2. Specific service charges rather than billable work orders should be applied when:
   - The time and resources required to perform the activity and related costs are relatively uniform for each transaction
   - Tracking costs via billable work orders would require some additional to extensive administrative activity.

3. Billable work orders rather than specific service charges should be applied when:
   - The resources, time and related costs, that is the input costs, to perform the activity vary from transaction to transaction
   - Business processes and tools exist to track actual time and materials costs.

As a result of that review, BPI is proposing to make certain changes to its specific service charges. BPI wishes to remove two charges, which are currently on its existing Schedule of Rates and Charges, and to add two charges, both at the Board's default rate as set out in the 2006 Electricity Distribution Rate Handbook.

Charges to be removed from Schedule of Specific Service Charges:

- **Arrears Certificate**

BPI proposes to remove the Arrears Certificate specific service charge ($15). BPI has concerns regarding the privacy implications of continuing to provide this service. Since 2008, BPI has charged this specific service 119 times per year on average, representing average yearly revenue of $1,785. BPI has included in its forecast of revenues $150 in revenue from this specific service charge for 2013. This has been included as BPI will continue to issue arrears certificates until the implementation date of the Schedule of Specific Charges resulting from this Application.

- **Temporary Install/Remove Overhead - With transformer**

BPI is proposing to cease charging for this service through specific service charges. BPI has determined it would be more appropriate to recover costs through billable work orders for this service. Billable work orders charged on a time and materials basis will more fully reflect the cost to provide these forms of service, which vary depending on the complexity of the particular assets and temporary connection service requirements in question.

The treatment of billable work order charges is described in BPI's Conditions of Service.

Charges to be added to Schedule of Specific Service Charges:

- **Meter Removal without Authorization**

BPI proposes to add the Meter Removal without Authorization charge, at the Board's default rate of $60. A revenue forecast in the amount of $1,200 has been included in BPI's forecast of revenue offsets.

- **Install/Remove Load Control Device after Business Hours**

BPI proposes to add this charge, at the Board's default rate of $185. A revenue forecast in the amount of $925 has been included in BPI's forecast of revenue offsets.

Below in Table 3.35 is a summary of the current and proposed specific service charges.

Table 3.35: Current and Proposed Specific Service Charges

Current Specific Service Charges	Charge- Board Default	Proposed Specific Service Charges	Charge- Board Default
	Customer Administration		
Arrears Certificate	**$ 15.00**		
Easement Letter	$ 15.00	Easement Letter	$ 15.00
Credit Reference/Check (plus any credit acgency costs applicable)	$ 15.00	Credit Reference/Check (plus any credit acgency costs applicable)	$ 15.00
Returned cheque charge (plus any bank charges)	$ 15.00	Returned cheque charge (plus any bank charges)	$ 15.00
Account set up charge/change of occupancy (plus credit agency costs if applicable)	$ 30.00	Account set up charge/change of occupancy (plus credit agency costs if applicable)	$ 30.00
Meter dispute charge (plus any Measurement Canada fees, if meter found correct)	$ 30.00	Meter dispute charge (plus any Measurement Canada fees, if meter found correct)	$ 30.00
	Non-Payment of Account		
Late Payment- per month	1.50%	Late Payment- per month	1.50%
Late Payment- per annum	19.56%	Late Payment- per annum	19.56%
Collection of account charge- no disconnection	$ 30.00	Collection of account charge- no disconnection	$ 30.00
Disconnect/Reconnect- at meter- regular hours	$ 65.00	Disconnect/Reconnect- at meter- regular hours	$ 65.00
Disconnect/Reconnect- at meter- after regular hours	$ 185.00	Disconnect/Reconnect- at meter- after regular hours	$185.00
Disconnect/Reconnect- at pole- regular hours	$ 185.00	Disconnect/Reconnect- at pole- regular hours	$185.00
Disconnect/Reconnect- at pole- after regular hours	$ 415.00	Disconnect/Reconnect- at pole- after regular hours	$415.00
	Other		
Install/remove load control device- regular hours	$ 65.00	Install/remove load control device- regular hours	$ 65.00
Temporary Service- Install and remove- Overhead- no transformer	$ 500.00	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- Underground- no transformer	$300.00
Temporary Service- Install and remove- Overhead- with transformer	**$ 1,000.00**		
Access to the Power Poles- per pole, per year	$ 22.35	Access to the Power Poles- per pole, per year	$ 22.35
		Meter removal without authorization	**$ 60.00**
		Install/remove load control device after business hours	**$185.00**