Exhibit 2 – Rate Base

Contents

EXHIBIT 2 – RATE BASE

The evidence presented in this exhibit provides information supporting the value of assets, on which a public utility is permitted to earn a specified rate of return, in accordance with rules set by the Ontario Energy Board. The evidence is organized according to the following topics;

1) Overview of Rate Base
2) Capital Expenditures
3) Service Quality and Reliability Performance

Tab 1 – Overview Rate Base

E2.T1.S1 OVERVIEW

CHEI's 2014 Rate Base is determined by taking the average of the balances at the beginning and the end of the 2014 Test Year, plus a working capital allowance of 13% of the sum of the cost of power and controllable expenses. The use of a 13% rate is consistent with the Board's letter of April 12, 2012.

The net fixed assets include distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. CHEI does not have non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Table 1 below presents the applicant's Rate Base calculations for all required years including the 2014 Test Year. CHEI has calculated its 2014 rate base to be $2,882,427. This rate base is also used to determine the proposed revenue requirement found at E6.T1.S2.

Table 1- Rate Base Trend Table

Particulars	Test Year 2014	Bridge Year 2013	Actual 2012	Actual 2011	Actual 2010	Board Appr 2010
Net Capital Assets in Service:						
Opening Balance	2,201,600	2,017,237	1,829,216	1,896,119	1,827,427	1,936,516
Ending Balance	2,543,766	2,201,600	2,017,237	1,829,216	1,896,119	2,032,895
Average Balance	**2,372,683**	**2,109,418**	**1,923,226**	**1,862,668**	**1,861,773**	**1,984,706**
Working Capital Allowance	509,744	534,061	493,428	473,744	434,643	446,322
Total Rate Base	**2,882,427**	**2,643,479**	**2,416,654**	**2,336,412**	**2,296,417**	**2,431,028**
Expenses for Working Capital	CGAAP					
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	20,900	15,550	16,298	20,965	20,827	33,860
3550-Distribution Expenses - Maintenance	40,300	39,800	48,629	39,319	36,633	37,425
3650-Billing and Collecting	170,174	134,057	135,426	163,139	146,429	155,247
3700-Community Relations	4,000	3,100	6,710	1,316	2,182	3,000
3800-Administrative and General Expenses	320,905	320,278	317,534	308,264	263,128	265,695
Total Eligible Distribution Expenses	**556,279**	**512,785**	**524,597**	**533,003**	**469,199**	**495,227**
3350-Power Supply Expenses	3,364,829	3,047,621	2,764,923	2,625,292	2,428,424	2,480,255
Total Expenses for Working Capital	**3,921,108**	**3,560,407**	**3,289,520**	**3,158,295**	**2,897,623**	**2,975,482**
Working Capital factor	13%	15%	15%	15%	15%	15%
Total Working Capital	**509,744**	**534,061**	**493,428**	**473,744**	**434,643**	**446,322**

The Rate Base for 2014 has increased by $238K over 2013 and $451K over the 2010 Board Approved Rate Base. The reason for the considerable increase in 2014 is mainly attributed to need to invest in the distribution system in order to accommodate a new subdivision planned for 2014-2015. This capital investment is discussed in detail at E2.T2.S4 and E2.T2.S7. Another significant reason for the increase is the inclusion of $314,417 in Smart Meter Related Capital expenditures into the Test Year's Rate Base. Further details on the topic of Smart Meters can also be found at E2.T1.S7 and E2.T2.S4.

The Working Capital Allowance has decreased by $24K over 2013 and increased by $63K over the 2010 Board Approved Working Capital Allowance. The reason for the decrease from 2014 to 2013 is due to the change in Working Capital Allowance rate from 15% to 13%. The overall increase from the last cost of service is mirrors the increase in OM&A and Power Supply Expense.

E2.T1.S2 RATE BASE VARIANCE DRIVERS

Detailed variance analysis on the rate base is presented in Table 2 below.

Table 2- 2014-2013Rate Base Variance

Particulars	Test Year 2014	Bridge Year 2013	Var	%
Net Capital Assets in Service:				
Opening Balance	2,201,600	2,017,237	184,364	9%
Ending Balance	2,543,766	2,201,600	342,166	16%
Average Balance	2,372,683	2,109,418	263,265	12%
Working Capital Allowance	509,744	534,061	-24,317	-5%
Total Rate Base	2,882,427	2,643,479	238,948	9%

2014 Test Year vs. 2012 Bridge Year:

The total projected average balance in 2014 of $2.3 million is $263K or 12% greater than 2013. The main reason for this increase is the significant monies budgeted for underground conductors and devices ($398K), and line transformers (87K) to accommodate a new subdivision planned for 2014-2015. The utility has also budgeted additional smart meters (31K) for this new subdivision. The utility is planning to replace a dozen poles as a result of its asset assessment. Details regarding pole replacements can be found in the Asset Management Plan at E2.T2.S7. The rest of the increase can be attributed to regular maintenance of the distribution system.

Table 3 - 2013-2012 Rate Base Variance

Particulars	Bridge Year 2013	Actual 2012	Var	%
Net Capital Assets in Service:				
Opening Balance	2,017,237	1,829,216	188,020	10%
Ending Balance	2,201,600	2,017,237	184,364	9%
Average Balance	2,109,418	1,923,226	186,192	10%
Working Capital Allowance	534,061	493,428	40,633	8%
Total Rate Base	2,643,479	2,416,654	226,825	9%

2013 Bridge Year vs. 2012 Actual:

The total projected average balance in 2013 of $2.1 million is $186K or 10% greater than 2012. The increase is primarily due to significant monies budgeted for overhead and underground conductors and devices ($111K), and poles and transformers (84K). CHEI has also budgeted (62K) for upgrades to its Distribution Station Equipment in advance of the subdivision going in in 2014-2015. All capital expenditures listed above are required to power the new subdivision.

Table 4 - 2012-2011 Rate Base Variance

Particulars	Actual 2012	Actual 2011	Var	%
Net Capital Assets in Service:				
Opening Balance	1,829,216	1,896,119	-66,903	-4%
Ending Balance	2,017,237	1,829,216	188,020	10%
Average Balance	1,923,226	1,862,668	60,559	3%
Working Capital Allowance	493,428	473,744	19,684	4%
Total Rate Base	2,416,654	2,336,412	80,242	3%

2012 Actual vs. 2011 Actual:

The total average balance in 2012 of $1.9 million is $61K greater than 2011. The main contributor to this increase is the inclusion of Smart Meters in Rate Base in the amount of 310K.

This increase is offset by the removal of stranded conventional meters from Rate Base and other cost savings and deferrals during 2012.

Table 5 - 2011-2010 Rate Base Variance

Particulars	Actual 2011	Actual 2010	Var	%
Net Capital Assets in Service:				
Opening Balance	1,896,119	1,827,427	68,692	4%
Ending Balance	1,829,216	1,896,119	-66,903	-4%
Average Balance	1,862,668	1,861,773	895	0%
Working Capital Allowance	473,744	434,643	39,101	9%
Total Rate Base	2,336,412	2,296,417	39,995	2%

2011Actual vs. 2010 Actual:

The average balance in 2011 of $1.8 million is $1,000. The increase is marginal and is attributed to regular maintenance of the distribution system.

E2.T1.S3 GROSS ASSET – PROPERTY PLAN AND EQUIPMENT

CHEI's Assets are broken down by the following functions.

Table 6 – Asset Breakdown

OEB	2014 Test Year	2013 Bridge Year	2012 Actual	2011 Actual	2010 Actual	2010 Board Approved	2009 Actual
1300-Intangible Plant	146,427	111,427	84,927	84,927	83,427	78,843	0
1450-Distribution Plant	4,455,437	3,855,842	3,581,442	3,300,201	3,252,320	3,559,226	3,136,747
1500-General Plant	89,746	89,746	86,747	79,797	62,783	68,957	121,497
1550-Other Capital Assets	-720,963	-560,963	-552,963	-551,363	-543,589	-690,099	-421,428
Total	**3,970,647**	**3,496,052**	**3,200,153**	**2,913,562**	**2,854,941**	**3,016,927**	**2,836,816**

E2.T1.S4 CONTINUITY STATEMENTS – APPENDIX 2-B

The Continuity Schedule calculates the cost, accumulated amortization, and net book value (NBV) for each Capital USoA. The information is presented for all relevant years at the next pages.

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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)		$ 22,086	$ 61,341		$ 83,427	-$ 15,802	-$ 12,613		-$ 28,414	$ 55,012
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 50,000			$ 50,000				$ -	$ 50,000
47	1808	Buildings					$ -				$ -	$ -
13	1810	Leasehold Improvements					$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 197,552	$ 24,966		$ 222,518	-$ 59,609	-$ 7,000		-$ 66,609	$ 155,909
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 480,083	$ 62,256		$ 542,339	-$ 143,915	-$ 20,448		-$ 164,363	$ 377,976
47	1835	Overhead Conductors & Devices		$ 541,906	$ 856		$ 542,762	-$ 162,199	-$ 21,693		-$ 183,892	$ 358,870
47	1840	Underground Conduit					$ -				$ -	$ -
47	1845	Underground Conductors & Devices		$ 952,146			$ 952,146	-$ 293,632	-$ 38,086		-$ 331,718	$ 620,428
47	1850	Line Transformers		$ 661,053	$ 28,328		$ 689,381	-$ 183,967	-$ 27,009		-$ 210,976	$ 478,405
47	1855	Services (Overhead & Underground)		$ 161,465	$ 12,637		$ 174,102	-$ 32,541	-$ 6,711		-$ 39,252	$ 134,850
47	1860	Meters		$ 79,072			$ 79,072	-$ 26,659	-$ 3,163		-$ 29,822	$ 49,250
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land					$ -				$ -	$ -
47	1908	Buildings & Fixtures					$ -				$ -	$ -
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 31,696	$ 3,013		$ 34,709	-$ 14,472	-$ 3,320		-$ 17,792	$ 16,917
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 16,392	$ 3,080		$ 19,472	-$ 13,940	-$ 1,466		-$ 15,406	$ 4,066
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -				$ -	$ -
10	1930	Transportation Equipment					$ -				$ -	$ -
8	1935	Stores Equipment		$ 4,320			$ 4,320	-$ 2,290	-$ 432		-$ 2,722	$ 1,598
8	1940	Tools, Shop & Garage Equipment					$ -				$ -	$ -
8	1945	Measurement & Testing Equipment		$ 4,281			$ 4,281	-$ 3,266	-$ 383		-$ 3,649	$ 632
8	1950	Power Operated Equipment					$ -				$ -	$ -
8	1955	Communications Equipment					$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)					$ -				$ -	$ -
8	1960	Miscellaneous Equipment					$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -				$ -	$ -
47	1980	System Supervisor Equipment					$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets					$ -				$ -	$ -
47	1995	Contributions & Grants		-$ 532,166	-$ 11,423		-$ 543,589	$ 109,833	$ 21,515		$ 135,796	-$ 407,793
	etc.						$ -				$ -	$ -
		Total		**$ 2,669,886**	**$ 185,054**	**$ -**	**$ 2,854,940**	**-$ 842,459**	**-$ 120,810**	**$ -**	**-$ 958,820**	**$ 1,896,119**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	$ -

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

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Appendix 2-B
Fixed Asset Continuity Schedule

Year **2011**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 83,427	$ 1,500		$ 84,927	-$ 28,414	-$ 13,707		-$ 42,121	$ 42,806
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 50,000			$ 50,000	$ -			$ -	$ 50,000
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 222,488			$ 222,488	-$ 66,609	-$ 7,416		-$ 74,025	$ 148,463
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 542,339	$ 18,097		$ 560,436	-$ 164,363	-$ 22,056		-$ 186,419	$ 374,017
47	1835	Overhead Conductors & Devices		$ 542,762	$ 4,224		$ 546,986	-$ 183,892	-$ 21,795		-$ 205,687	$ 341,299
47	1840	Underground Conduit		$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices		$ 952,146			$ 952,146	-$ 331,718	-$ 38,086		-$ 369,804	$ 582,342
47	1850	Line Transformers		$ 689,381	$ 21,554		$ 710,935	-$ 210,976	-$ 28,006		-$ 238,982	$ 471,953
47	1855	Services (Overhead & Underground)		$ 174,102	$ 4,036		$ 178,138	-$ 39,252	-$ 7,045		-$ 46,297	$ 131,841
47	1860	Meters		$ 79,072			$ 79,072	-$ 29,822	-$ 3,163		-$ 32,985	$ 46,087
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 34,709	$ 14,694		$ 49,403	-$ 17,792	-$ 3,856		-$ 21,648	$ 27,755
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 19,472	$ 2,319		$ 21,791	-$ 15,406	-$ 1,703		-$ 17,109	$ 4,682
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment		$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment		$ 4,320			$ 4,320	-$ 2,722	-$ 432		-$ 3,154	$ 1,166
8	1940	Tools, Shop & Garage Equipment		$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment		$ 4,281			$ 4,281	-$ 3,649	-$ 158		-$ 3,807	$ 474
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 543,589	-$ 7,774		-$ 551,363	$ 135,796	$ 21,899		$ 157,695	-$ 393,668
	1610	Intagible Asset (H1)		$ -			$ -	$ -			$ -	$ -
								$ -				
		Total		**$ 2,854,910**	**$ 58,650**	**$ -**	**$ 2,913,560**	**-$ 958,820**	**-$ 125,523**	**$ -**	**-$ 1,084,344**	**$ 1,829,216**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	$ -

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

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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)		$ 84,927			$ 84,927	-$ 42,121	-$ 13,857		-$ 55,978	$ 28,949
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -	$ -		$ -	$ -
N/A	1805	Land		$ 50,000			$ 50,000	$ -	$ -		$ -	$ 50,000
47	1808	Buildings		$ -			$ -	$ -	$ -		$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 222,488			$ 222,488	-$ 74,025	-$ 7,416		-$ 81,442	$ 141,046
47	1825	Storage Battery Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 560,436	$ 3,098		$ 563,534	-$ 186,419	-$ 22,479		-$ 208,898	$ 354,636
47	1835	Overhead Conductors & Devices		$ 546,986			$ 546,986	-$ 205,687	-$ 21,879		-$ 227,567	$ 319,419
47	1840	Underground Conduit		$ -			$ -	$ -	$ -		$ -	$ -
47	1845	Underground Conductors & Devices		$ 952,146	$ 5,841		$ 957,987	-$ 369,804	-$ 38,203		-$ 408,006	$ 549,981
47	1850	Line Transformers		$ 710,935	$ 36,088		$ 747,023	-$ 238,982	-$ 29,159		-$ 268,141	$ 478,882
47	1855	Services (Overhead & Underground)		$ 178,138	$ 5,074		$ 183,212	-$ 46,297	-$ 7,227		-$ 53,524	$ 129,688
47	1860	Meters		$ 79,072		-$ 79,072	$ -	-$ 32,985	$ -	$ 32,985	$ 0	$ 0
47	1860	Meters (Smart Meters)		$ -	$ 310,212		$ 310,212	$ -	-$ 6,204		-$ 6,204	$ 304,008
N/A	1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 49,403			$ 49,403	-$ 21,648	-$ 4,625		-$ 26,273	$ 23,130
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 21,791	$ 2,746		$ 24,537	-$ 17,109	-$ 1,793		-$ 18,903	$ 5,634
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment		$ 4,320			$ 4,320	-$ 3,154	-$ 432		-$ 3,586	$ 734
8	1940	Tools, Shop & Garage Equipment		$ -	$ 4,205		$ 4,205	$ -	-$ 210		-$ 210	$ 3,995
8	1945	Measurement & Testing Equipment		$ 4,281			$ 4,281	-$ 3,807	-$ 158		-$ 3,965	$ 316
8	1950	Power Operated Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 551,363	-$ 1,600		-$ 552,963	$ 157,695	$ 22,087		$ 179,782	-$ 373,181
								$ -				
								$ -				
	etc.						$ -				$ -	$ -
		Total		**$ 2,913,560**	**$ 365,664**	**-$ 79,072**	**$ 3,200,152**	**-$ 1,084,344**	**-$ 131,557**	**$ 32,985**	**-$ 1,182,915**	**$ 2,017,237**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 32,985

Notes:

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2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

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Appendix 2-B
Fixed Asset Continuity Schedule

Year 2013

				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)		$ 84,927	$ 26,500		$ 111,427	-$ 55,978	-$ 16,507		-$ 72,485	$ 38,942
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -	$ -		$ -	$ -
N/A	1805	Land		$ 50,000			$ 50,000	$ -	$ -		$ -	$ 50,000
47	1808	Buildings		$ -			$ -	$ -	$ -		$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 222,488	$ 62,400		$ 284,888	-$ 81,442	-$ 4,613		-$ 86,054	$ 198,834
47	1825	Storage Battery Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 563,534	$ 83,850		$ 647,384	-$ 208,898	-$ 15,136		-$ 224,035	$ 423,349
47	1835	Overhead Conductors & Devices		$ 546,986	$ 58,750		$ 605,736	-$ 227,567	-$ 9,606		-$ 237,173	$ 368,563
47	1840	Underground Conduit		$ -			$ -	$ -	$ -		$ -	$ -
47	1845	Underground Conductors & Devices		$ 957,987	$ 52,400		$ 1,010,387	-$ 408,006	-$ 28,120		-$ 436,126	$ 574,261
47	1850	Line Transformers		$ 747,023	$ 12,000		$ 759,023	-$ 268,141	-$ 18,826		-$ 286,967	$ 472,056
47	1855	Services (Overhead & Underground)		$ 183,212	$ 5,000		$ 188,212	-$ 53,524	-$ 4,643		-$ 58,167	$ 130,045
47	1860	Meters		$ -			$ -	$ 0	$ -		$ 0	$ 0
47	1860	Meters (Smart Meters)		$ 310,212			$ 310,212	-$ 6,204	-$ 20,681		-$ 26,885	$ 283,327
N/A	1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 49,403	$ 1,500		$ 50,903	-$ 26,273	-$ 4,540		-$ 30,813	$ 20,090
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 24,537	$ 1,500		$ 26,037	-$ 18,903	-$ 1,779		-$ 20,682	$ 5,355
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment		$ 4,320			$ 4,320	-$ 3,586	-$ 432		-$ 4,018	$ 302
8	1940	Tools, Shop & Garage Equipment		$ 4,205			$ 4,205	-$ 210	-$ 421		-$ 631	$ 3,574
8	1945	Measurement & Testing Equipment		$ 4,281			$ 4,281	-$ 3,965	-$ 158		-$ 4,123	$ 158
8	1950	Power Operated Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 552,963	-$ 8,000		-$ 560,963	$ 179,782	$ 13,924		$ 193,706	-$ 367,257
	etc.						$ -				$ -	$ -
		Total		**$ 3,200,152**	**$ 295,900**	**$ -**	**$ 3,496,052**	**-$ 1,182,915**	**-$ 111,536**	**$ -**	**-$ 1,294,452**	**$ 2,201,600**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	$ -

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

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Appendix 2-B
Fixed Asset Continuity Schedule

Year **2014**

				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)		$ 111,427	$ 35,000		$ 146,427	-$ 72,485	-$ 22,013		-$ 94,498	$ 51,929
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -	$ -		$ -	$ -
N/A	1805	Land		$ 50,000			$ 50,000	$ -	$ -		$ -	$ 50,000
47	1808	Buildings		$ -			$ -	$ -	$ -		$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 284,888			$ 284,888	-$ 86,054	-$ 5,180		-$ 91,234	$ 193,654
47	1825	Storage Battery Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 647,384	$ 60,220		$ 707,604	-$ 224,035	-$ 16,937		-$ 240,972	$ 466,632
47	1835	Overhead Conductors & Devices		$ 605,736	$ 19,375		$ 625,111	-$ 237,173	-$ 10,257		-$ 247,430	$ 377,681
47	1840	Underground Conduit		$ -			$ -	$ -	$ -		$ -	$ -
47	1845	Underground Conductors & Devices		$ 1,010,387	$ 398,000		$ 1,408,387	-$ 436,126	-$ 34,554		-$ 470,680	$ 937,707
47	1850	Line Transformers		$ 759,023	$ 87,500		$ 846,523	-$ 286,967	-$ 20,069		-$ 307,036	$ 539,487
47	1855	Services (Overhead & Underground)		$ 188,212	$ 4,000		$ 192,212	-$ 58,167	-$ 4,755		-$ 62,922	$ 129,290
47	1860	Meters		$ -			$ -	$ 0	$ -		$ 0	$ 0
47	1860	Meters (Smart Meters)		$ 310,212	$ 30,500		$ 340,712	-$ 26,885	-$ 21,697		-$ 48,583	$ 292,129
N/A	1905	Land		$ -			$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ -			$ -	$ -	$ -		$ -	$ -
13	1910	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 50,903			$ 50,903	-$ 30,813	-$ 4,331		-$ 35,144	$ 15,759
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware		$ 26,037			$ 26,037	-$ 20,682	-$ 1,929		-$ 22,611	$ 3,426
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1935	Stores Equipment		$ 4,320			$ 4,320	-$ 4,018	-$ 151		-$ 4,169	$ 151
8	1940	Tools, Shop & Garage Equipment		$ 4,205			$ 4,205	-$ 631	-$ 421		-$ 1,051	$ 3,154
8	1945	Measurement & Testing Equipment		$ 4,281			$ 4,281	-$ 4,123	-$ 158		-$ 4,282	-$ 1
8	1950	Power Operated Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -	$ -		$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -	$ -		$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 560,963	-$ 160,000		-$ 720,963	$ 193,706	$ 10,024		$ 203,730	-$ 517,233
		Smart Meter Additions (from 1555)		$ -			$ -	$ -	$ -		$ -	$ -
8	1860	Meters (Smart Meters)										
45.1	1920	Computer Hardware (Smart Meters)										
12	1925	Computer Software (Smart Meters)										
	etc.							$ -	$ -			
								$ -	$ -			
		Total		**$ 3,496,052**	**$ 474,595**	**$ -**	**$ 3,970,647**	**-$ 1,294,452**	**-$ 132,429**	**$ -**	**-$ 1,426,881**	**$ 2,543,766**
											-$ 1,536,113	

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ -

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The depreciation column (D) is not required as the relevant information will be provided in the following 2-C series of appendices.

E2.T1.S5 ACCUMULATED DEPRECIATION - APPENDIX 2-D

CHEI has adopted depreciation rates based on the Kenectrics report. The relevant rates (accounts with a balance) used are presented in Table 7 below and Continuity Schedules of the Accumulated Depreciation are presented at the next pages.

Table 7 – Comparison of Depreciation Rates

Account	Description	CGAAP	Modified CGAAP Post 2012
1611	Computer Software (Formally known as Account 1925)	5.00	5.00
1820	Distribution Station Equipment <50 kV	30.00	55.00
1830	Poles, Towers & Fixtures	25.00	40.00
1835	Overhead Conductors & Devices	25.00	60.00
1845	Underground Conductors & Devices	25.00	35.00
1850	Line Transformers	25.00	40.00
1855	Services (Overhead & Underground)	25.00	40.00
1860	Meters	25.00	25.00
1860	Meters (Smart Meters)	25.00	15.00
1915	Office Furniture & Equipment (10 years)	10.00	10.00
1920	Computer Equipment - Hardware	5.00	5.00
1935	Stores Equipment	10.00	10.00
1940	Tools, Shop & Garage Equipment	10.00	10.00
1945	Measurement & Testing Equipment	10.00	10.00
1995	Contributions & Grants	25.00	40.00

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Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 84,927.00	$ 15,643.30	$ 69,283.70	$ -	$ 69,283.70	5.00	20.00%	$ 13,856.74	$ 13,856.74	$ -
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 50,000.00		$ 50,000.00	$ -	$ 50,000.00	-		$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 222,488.00		$ 222,488.00	$ -	$ 222,488.00	30.00	3.33%	$ 7,416.27	$ 7,416.27	$ -
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 560,436.00		$ 560,436.00	$ 3,098.00	$ 561,985.00	25.00	4.00%	$ 22,479.40	$ 22,479.40	$ 0.00
1835	Overhead Conductors & Devices	$ 546,986.00		$ 546,986.00	$ -	$ 546,986.00	25.00	4.00%	$ 21,879.44	$ 21,879.44	$ -
1840	Underground Conduit	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 952,146.00		$ 952,146.00	$ 5,841.00	$ 955,066.50	25.00	4.00%	$ 38,202.66	$ 38,202.66	$ 0.00
1850	Line Transformers	$ 710,935.00		$ 710,935.00	$ 36,088.00	$ 728,979.00	25.00	4.00%	$ 29,159.16	$ 29,159.16	$ -
1855	Services (Overhead & Underground)	$ 178,138.00		$ 178,138.00	$ 5,074.00	$ 180,675.00	25.00	4.00%	$ 7,227.00	$ 7,227.00	$ -
1860	Meters	$ 79,072.00	$ 79,072.00	$ -	$ -	$ -	25.00	4.00%	$ -		$ -
1860	Meters (Smart Meters)	$ -		$ -	$ 310,212.00	$ 155,106.00	25.00	4.00%	$ 6,204.24	$ 6,204.24	$ -
1905	Land	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 49,403.00	$ 3,155.55	$ 46,247.45	$ -	$ 46,247.45	10.00	10.00%	$ 4,624.75	$ 4,624.70	$ 0.05
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 21,791.00	$ 14,197.89	$ 7,593.11	$ 2,746.00	$ 8,966.11	5.00	20.00%	$ 1,793.22	$ 1,793.22	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1930	Transportation Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1935	Stores Equipment	$ 4,320.00		$ 4,320.00	$ -	$ 4,320.00	10.00	10.00%	$ 432.00	$ 432.00	$ -
1940	Tools, Shop & Garage Equipment	$ -		$ -	$ 4,205.00	$ 2,102.50	10.00	10.00%	$ 210.25	$ 210.25	$ -
1945	Measurement & Testing Equipment	$ 4,281.00	$ 2,700.00	$ 1,581.00	$ -	$ 1,581.00	10.00	10.00%	$ 158.10	$ 158.10	$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 551,363.00		-$ 551,363.00	-$ 1,600.00	-$ 552,163.00	25.00	4.00%	-$ 22,086.52	-$ 22,086.52	$ -
etc.		$ -		$ -	$ -	$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 2,913,560.00	$ 114,768.74	$ 2,798,791.26	$ 365,664.00	$ 2,981,623.26			$ 131,556.70	$ 131,556.66	$ 0.05

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

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Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2013 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2013 Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 84,927.00	$ 15,643.30	$ 69,283.70	$ 26,500.00	$ 82,533.70	5.00	20.00%	$ 16,506.74	$ 16,506.79	-$ 0.05
1612	Land Rights (Formally known as Account 1906)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1805	Land	$ 50,000.00		$ 50,000.00		$ 50,000.00		0.00%	$ -	$ -	$ -
1808	Buildings	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 222,488.00		$ 222,488.00	$ 62,400.00	$ 253,688.00	55.00	1.82%	$ 4,612.51	$ 4,612.50	$ 0.01
1825	Storage Battery Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 563,534.00		$ 563,534.00	$ 83,850.00	$ 605,459.00	40.00	2.50%	$ 15,136.48	$ 15,136.46	$ 0.02
1835	Overhead Conductors & Devices	$ 546,986.00		$ 546,986.00	$ 58,750.00	$ 576,361.00	60.00	1.67%	$ 9,606.02	$ 9,606.03	-$ 0.01
1840	Underground Conduit	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 957,987.00		$ 957,987.00	$ 52,400.00	$ 984,187.00	35.00	2.86%	$ 28,119.63	$ 28,119.62	$ 0.01
1850	Line Transformers	$ 747,023.00		$ 747,023.00	$ 12,000.00	$ 753,023.00	40.00	2.50%	$ 18,825.58	$ 18,825.55	$ 0.03
1855	Services (Overhead & Underground)	$ 183,212.00		$ 183,212.00	$ 5,000.00	$ 185,712.00	40.00	2.50%	$ 4,642.80	$ 4,642.76	$ 0.04
1860	Meters	$ -		$ -		$ -	25.00	4.00%	$ -		$ -
1860	Meters (Smart Meters)	$ 310,212.00		$ 310,212.00		$ 310,212.00	15.00	6.67%	$ 20,680.80	$ 20,680.80	$ -
1905	Land	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 49,403.00	$ 4,750.24	$ 44,652.76	$ 1,500.00	$ 45,402.76	10.00	10.00%	$ 4,540.28	$ 4,540.27	$ 0.01
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 24,537.00	$ 16,392.44	$ 8,144.56	$ 1,500.00	$ 8,894.56	5.00	20.00%	$ 1,778.91	$ 1,779.19	-$ 0.28
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ 4,320.00		$ 4,320.00		$ 4,320.00	10.00	10.00%	$ 432.00	$ 432.00	$ -
1940	Tools, Shop & Garage Equipment	$ 4,205.00		$ 4,205.00		$ 4,205.00	10.00	10.00%	$ 420.50	$ 420.50	$ -
1945	Measurement & Testing Equipment	$ 4,281.00	$ 2,700.00	$ 1,581.00		$ 1,581.00	10.00	10.00%	$ 158.10	$ 158.10	$ -
1950	Power Operated Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 552,963.00		-$ 552,963.00	-$ 8,000.00	-$ 556,963.00	40.00	2.50%	-$ 13,924.08	-$ 13,924.08	$ 0.00
etc.				$ -		$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ 3,200,152.00	$ 39,485.98	$ 3,160,666.02	$ 295,900.00	$ 3,308,616.02			$ 111,536.26	$ 111,536.49	-$ 0.23

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

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Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2014 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2014 Depreciation Expense (h) = (e) / (f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 111,427.00	$ 18,864.54	$ 92,562.46	$ 35,000.00	$ 110,062.46	5.00	20.00%	$ 22,012.49	$ 22,013.00	-$ 0.51
1612	Land Rights (Formally known as Account 1906)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1805	Land	$ 50,000.00		$ 50,000.00		$ 50,000.00		0.00%	$ -	$ -	$ -
1808	Buildings	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 284,888.00		$ 284,888.00		$ 284,888.00	55.00	1.82%	$ 5,179.78	$ 5,179.77	$ 0.01
1825	Storage Battery Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 647,384.00		$ 647,384.00	$ 60,220.00	$ 677,494.00	40.00	2.50%	$ 16,937.35	$ 16,937.35	$ -
1835	Overhead Conductors & Devices	$ 605,736.00		$ 605,736.00	$ 19,375.00	$ 615,423.50	60.00	1.67%	$ 10,257.06	$ 10,257.06	-$ 0.00
1840	Underground Conduit	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 1,010,387.00		$ 1,010,387.00	$ 398,000.00	$ 1,209,387.00	35.00	2.86%	$ 34,553.91	$ 34,553.91	$ 0.00
1850	Line Transformers	$ 759,023.00		$ 759,023.00	$ 87,500.00	$ 802,773.00	40.00	2.50%	$ 20,069.33	$ 20,069.30	$ 0.03
1855	Services (Overhead & Underground)	$ 188,212.00		$ 188,212.00	$ 4,000.00	$ 190,212.00	40.00	2.50%	$ 4,755.30	$ 4,755.26	$ 0.04
1860	Meters	$ -		$ -		$ -	25.00	4.00%	$ -		$ -
1860	Meters (Smart Meters)	$ 310,212.00		$ 310,212.00	$ 30,500.00	$ 325,462.00	15.00	6.67%	$ 21,697.47	$ 21,697.47	-$ 0.00
1905	Land	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 50,903.00	$ 7,592.64	$ 43,310.36		$ 43,310.36	10.00	10.00%	$ 4,331.04	$ 4,331.05	-$ 0.01
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 26,037.00	$ 16,392.44	$ 9,644.56		$ 9,644.56	5.00	20.00%	$ 1,928.91	$ 1,929.19	-$ 0.28
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ 4,320.00	$ 2,808.00	$ 1,512.00		$ 1,512.00	10.00	10.00%	$ 151.20	$ 151.20	$ -
1940	Tools, Shop & Garage Equipment	$ 4,205.00		$ 4,205.00		$ 4,205.00	10.00	10.00%	$ 420.50	$ 420.50	$ -
1945	Measurement & Testing Equipment	$ 4,281.00	$ 2,700.00	$ 1,581.00		$ 1,581.00	10.00	10.00%	$ 158.10	$ 158.10	$ -
1950	Power Operated Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 560,963.00	-$160,000.00	-$ 400,963.00		-$ 400,963.00	40.00	2.50%	-$ 10,024.08	-$ 10,024.08	$ 0.00
etc.				$ -		$ -		0.00%	$ -	$ -	$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ 3,496,052.00	-$111,642.38	$ 3,607,694.38	$ 634,595.00	$ 3,924,991.88			$ 132,428.36	$ 132,429.08	-$ 0.72

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

E2.T1.S6 ALLOWANCE FOR WORKING CAPITAL

CHEI has used the 13% Allowance Approach for the purpose of calculating its Allowance for Working Capital. This was done in accordance with the letter issued by the Board on April 12, 2012. A rate of 13% was applied to the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

Table.8 below presents CHEI's calculations in determining its Allowance for Working Capital.

Table 8 – Determination of Working Capital Allowance.

Particulars	Test Year 2014
Net Capital Assets in Service:	
Opening Balance	2,201,600
Ending Balance	2,543,766
Average Balance	**2,372,683**
Working Capital Allowance	509,744
Total Rate Base	2,882,427

Eligible Distribution Expenses:	
3500-Distribution Expenses - Operation	20,900
3550-Distribution Expenses - Maintenance	40,300
3650-Billing and Collecting	170,174
3700-Community Relations	4,000
3800-Administrative and General Expenses	320,905
Total Eligible Distribution Expenses	**556,279**
3350-Power Supply Expenses	3,364,829
Total Expenses for Working Capital	**3,921,108**
Working Capital factor	13%
Total Working Capital	**509,744**

E2.T1.S7 SMART METER

On March 16, 2012, CHEI filed an application seeking Board approval for the disposition and recovery of costs related to smart meter deployment, offset by Smart Meter Funding Adder ("SMFA") revenues collected from May 1, 2006 to April 30, 2012. On August 23, 2012 the Board issued an Interim Rate Order making the current approved Tariff of Rates and Charges interim since CHEI had proposed an effective date of May 1, 2012 in their Application.

The Board noted in its decision that authorization to procure and deploy smart meters has been done in accordance with Government regulations, including successful participation in the London Hydro RFP process, overseen by the Fairness Commissioner, to select (a) vendor(s) for the procurement and/or installation of smart meters and related systems. The Board also noted that there was a significant degree of cost control discipline that distributors, including CHEI, were subject to in smart meter procurement and deployment. The Board further noted that CHEI had documented that it participated with other distributors in Eastern Ontario on smart meter procurement and operational processes to better realize cost savings and efficiencies.

As such, the Board approved the recovery of the costs for smart meter deployment and operation as of December 31, 2011 through a rate rider effective until CHEI's 2014 Cost of Service Application.

The Board's model and decision (Decision and Order, EB-2012-0094, dated August 23, 2012), which contains a summary of the specifics requested and approved, is presented at Appendix A and B of this Exhibit. The table below shows details of the capital expenditures that have been added to the utility's rate Rate Base.

Table 9: Aggregate Smart Meter Costs by Category

Smart Meter		$ 310,212
Tools & Equipment		$ 4,205
Total Capital Costs		**$ 314,417**

E2.T1.S8 TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT.

In its Smart Meter application CHEI stated: "No cost associated with stranded meters has been included in the application." The exclusion of stranded meters was consistent with the directions in G-2011-0001 Guideline: "Smart Meter Funding and Cost Recovery – Final Disposition", dated December 15, 2011.

CHEI's decision to exclude its stranded meter costs in its Smart Meter application was accepted in the Decision and Order, EB-2012-0094, dated August 23, 2012, where it was stated:

"In its Application, CHEI proposed not to dispose of stranded meters by way of stranded meter rate riders at this time, but to deal with disposition in its next rebasing application, scheduled for 2014 rates. Neither intervener nor Board staff took issue with CHEI's proposal. Board staff submitted that CHEI's proposal to defer recovery of stranded meter costs is compliant with Guideline G-2011-0001. "

Subsequently in the Decision and Order, the Board instructed CHEI to address both the recovery of all its stranded meter costs in its next rebasing application.

The cost of the stranded meters that CHEI is claiming in this current application is $42,924. This cost is the net of depreciation. The calculation of the proposed rate rider is presented at E8.T7.S1

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006							
2007							
2008							
2009							
2010		79,072	29,822				
2011		79,072	32,985		46,087		46,087
2012	(1)	79,072	36,148		42,924		42,924

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Tab 2 – Capital Expenditures

E2.T2.S1 OVERVIEW

This section provides an analysis of CHEI Capital Plan Projects. The analysis covers 2010 Actuals up to 2014 Test Year.

CHEI has been, and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. CHEI completes regular inspections throughout the year while carrying out necessary maintenance on the distribution system.

The reliability indices are recorded and monitored on an annual basis as demonstrated at E2.T3.S1. They are used to assess the asset condition which impacts the capital budgeting process. CHEI has an obligation to serve new growth within the service area in a timely and cost effective way. In order to fulfill this obligation, the municipality along with input from CHEI identifies all potential areas where new growth may occur, while recognizing that the actual timing of each possible new development is uncertain. Although growth has an impact on capital expenditures, reliability and safety are the main components taken into account.

The capital budget for 2014 reflects the level of growth that is anticipated based on input from the municipality and management judgment.

Each year CHEI looks at its distribution system and determines the needs to ensure only those capital investments that are required to ensure a safe and reliable operation of CHEI's distribution system are made.

E2.T2.S2 PROJECT TABLE - APPENDIX 2-A

Appendix 2-A – Project Table is presented at the next page.

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Appendix 2-A
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis							
1820-install new transformer							
feeding hydro metering unit			$ 22,389.75				
1820-new service at substation to							
supply power to fans and heaters							
in cubicle components			$ 2,576.00				
1820-groundy study substation						$ 10,000.00	
1820-add new switching cabinet 4th feeder						$ 52,400.00	
Sub-Total	$ -	$ -	$ 24,965.75	$ -	$ -	$ 62,400.00	$ -
1830-pole replacement different location	$ 18,322.50						
1830-pole replacement different location		$ 43,906.50					
1830-pole replacement on brisson,							
bourassa , lapalme & centenaire							
street			$ 62,255.50				
1830-poles replacement on st-jacques							
bourdeau,notre-dame & ste-marie				$ 18,096.52			
1830-pole replacement					$ 3,098.10		
1830-pole replacement at different							
location						$ 29,050.00	
1830-pole at ste-therese street						$ 54,800.00	
1830-pole replacement on	$ -						
st-jacques and forget							$ 20,750.00
1830-pole replacement on cloutier							
street							$ 39,470.00
Sub-Total	$ 18,322.50	$ 43,906.50	$ 62,255.50	$ 18,096.52	$ 3,098.10	$ 83,850.00	$ 60,220.00
1835-overhead conductor device	$ 73,491.56						
1835-overhead conductor device		$ 5,232.00					
1835-overhead conductor device			$ 856.00				
1835-overhead conductor device				$ 4,224.24			
1835-4th feeder ste-therese							
street						$ 58,750.00	
1835-4th feeder on cloutier							
street							$ 19,375.00
Sub-Total	$ 73,491.56	$ 5,232.00	$ 856.00	$ 4,224.24	$ -	$ 58,750.00	$ 19,375.00
1845-underground conductor	$ 12,204.00						
1845-underground conductor		$ 875.00					

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Appendix 2-A
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
1845-underground conductor							
hydro vac duck					$ 5,841.00		
1845-underground cable							
substation to ste-therese						$ 52,400.00	
1845-new subdivision							$ 398,000.00
Sub-Total	$ 12,204.00	$ 875.00	$ -	$ -	$ 5,841.00	$ 52,400.00	$ 398,000.00
1850-padmount & polemount							
transformers new & old	$ 26,501.00						
1850-padmount & polemount							
transformers new & old		$ 73,966.10					
1850-padmount & polemount							
transformers new & old			$ 28,327.65				
1850-padmount & polemount							
transformers new & old				$ 21,553.50			
1850-replacement of old							
transformers					$ 36,088.00		
1850-replacement of transformers							
& new services						$ 12,000.00	
1850-transformers for proposed							
subdivision & ldc need							$ 87,500.00
Sub-Total	$ 26,501.00	$ 73,966.10	$ 28,327.65	$ 21,553.50	$ 36,088.00	$ 12,000.00	$ 87,500.00
1855-new o.h. & u.g. services	$ 18,548.25						
material & labour							
1855-new o.h. & u.g. services		$ 11,372.75					
material & labour							
1855-new o.h. & u.g. services							
material & labour			$ 12,636.50				
1855-new o.h. & u.g. services							
material & labour				$ 4,036.25			
1855-new o.h. & u.g. services							
material & labour					$ 5,074.00		
1855-new o.h. & u.g. services							
material & labour						$ 5,000.00	
1855-new o.h. & u.g. services							
material & labour							$ 4,000.00
Sub-Total	$ 18,548.25	$ 11,372.75	$ 12,636.50	$ 4,036.25	$ 5,074.00	$ 5,000.00	$ 4,000.00
1860-smart meters					$ 310,212.00		$ 30,500.00
1860-smart meters - stranded					-$ 79,072.00		

File Number:	EB-20130122
Exhibit:	2
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Appendix 2-A
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Sub-Total	$ -	$ -	$ -	$ -	$ 231,140.00	$ -	$ 30,500.00
1915-office furniture & equipment							
bell system 2009		$ 2,732.86					
1915-audio materials			$ 3,012.54				
1915-folder, inserter, mailing machine				$ 14,694.00			
1915-cell phone & equipment						$ 1,500.00	
Sub-Total	$ -	$ 2,732.86	$ 3,012.54	$ 14,694.00	$ -	$ 1,500.00	$ -
1920-computer hardware	$ 2,194.55						
1920-computer hardware							
1920-new computer			$ 3,080.49				
1920-addition new printer				$ 2,319.90			
1920-new computer					$ 2,745.57		
1920-computer equipment and hardware							
battery back-up						$ 1,500.00	
Sub-Total	$ 2,194.55	$ -	$ 3,080.49	$ 2,319.90	$ 2,745.57	$ 1,500.00	$ -
1925-computer software equipment		$ 6,442.47					
1925-implementation new cis system-harris			$ 61,341.39				
1925-north star training cis system				$ 1,500.00			
1925-harris software moe standard bil print						$ 25,000.00	
1925-antivirus protection						$ 1,500.00	
1925-harris version 6.4 upgrade							$ 20,000.00
1925-harris customer connect							$ 15,000.00
1940 - Tools related to Smart Metering					$ 4,205.00		
Sub-total		$ 6,442.47	$ 61,341.39	$ 1,500.00	$ 4,205.00	$ 26,500.00	$ 35,000.00
1995 Capital Contribution			-$ 11,423.00	-$ 7,774.00	-$ 1,600.00	-$ 8,000.00	-$ 160,000.00
Total	**$ 151,261.86**	**$ 144,527.68**	**$ 185,052.82**	**$ 58,650.41**	**$ 286,591.67**	**$ 295,900.00**	**$ 474,595.00**

E2.T2.S3 PROJECT CLASSIFICATION AND CATEGORIZATION

CHEI uses as a guideline to project classification, the classification and categorization shown in Chapter 4 of the Filing Requirements for Electricity Distribution and Distribution Application. Entitled "Minimum Filing requirements for electricity distribution projects under Section 92 of the Ontario Energy Board Act ("the Act")"

CHEI has found the project Categorization, Classification to be helpful in determining the need and justification for projects.

Project Classification

Project Classification is the classification of a project into one of three project classes:

a) **Development projects** are those for providing:
   - an adequate supply capacity and/or maintaining an acceptable or prescribed level of customer or system reliability for load growth meeting increased stresses on the system; or
   - enhancing system efficiency such as minimizing congestion on the distribution system and reducing system losses.

b) **Connection projects** are those for providing connection of a load or generation customer or group of customers to the distribution system.

c) **Sustainment projects** are those for maintaining the performance of the distribution network at its current standard or replacing end-of-life facilities on a "like for like" basis.

It is acknowledged that projects can have elements of development, connection, or sustainment. In these cases, the applicant should identify the proportional make-up of the project, and then classify the project based on the predominant driver.

Project Categorization

The purpose of project categorization is to distinguish whether the project need is beyond the control of the ("Non-discretionary") or at the discretion of CHEI ("Discretionary"). The categorization stage identifies the project need as:

a) Non-discretionary – a "must do" project, the need for which is determined beyond the control of the applicant ("Non-discretionary"). Non-discretionary projects may be triggered or determined by such things as:

- mandatory requirement to satisfy obligations specified by regulatory organizations;
- a need to connect new load (of a distributor or large user) or new generation (connection);
- a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
- projects identified in a Board or provincial government approved plan;
- projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
- a need to comply with direction from the Ontario Energy Board in the event it is determined that the distribution system's reliability is at risk.

or

b) **Discretionary** – the need is determined at the discretion of the applicant (“Discretionary”). Discretionary projects are proposed by the applicant to enhance the distribution system performance, benefiting its users. Projects in this category may include:

- projects to reduce distribution system losses;
- projects to reduce congestion;
- projects to build a new or enhance an existing interconnection to increase generation reserve margin within the IESO-controlled grid, beyond the minimum level required;
- projects to enhance reliability beyond a minimum standard; and
- projects which add flexibility to the operation and maintenance of the distribution system.

Table 10 below shows the total investment in project by classification and categorization.

Table 10 – Summary of Project Need

Project Need			
		Project Categorization	
Project Classification		Non-Discretionary	Discretionary
	Development	$418,845	
	Connection	0	
	Sustainment/Maintenance	$40,750	$15,000

E2.T2.S4 HISTORICAL AND PROJECTED CAPITAL PLANS

The following section of The Application presents a breakdown of major capital projects for 2010 Actuals up to the 2014 Test Year.

2010 Capital Expenditures

GL ACT #	2010 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1820	INSTALL NEW TRANSFORMER FEEDING HYDRO METERING UNIT	**$ 22 389.75**
	NEW SERVICE AT SUBSTATION TO SUPPLY POWER TO FANS AND HEATERS IN CUBICLE COMPONENTS	**$ 2 576.25**
	SUB TOTAL	$ 24 966.00
1830	POLE REPLACEMENT BRISSON STREET	**$ 18 000.00**
	POLE REPLACEMENT BOURASSA STREET	**$ 22 000.00**
	POLE REPLACEMENT LAPALME STREET	**$ 16 000.00**
	POLE REPLACEMENT CENTENNAIRE STREET	**$ 6 256.00**
	SUB TOTAL	**$ 62 256. 00**
1835	INSTALLATION NEW SWITCH & ARRESTORS	**$ 856.00**
1850	PADMOUND&POLEMOUNT TRANSFORMER	**$ 28 328.00**
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	**$ 12 637.00**
1915	CSR's TELEPHONE HEAD SETS	**$ 3 013.00**
	PROJECTOR	
1920	NEW COMPUTER	**$ 3 080.00**
1925	IMPLEMENTATION NEW CIS SYSTEM - HARRIS	**$ 61 341.00**
1995	CONTRIBUTED CAPITAL	**-(11,423.00)**
	TOTAL	**$ 196 476.09**

INSTALLATION NEW TRANSFORMER

Scope:
Upgrade service at substation

Objectives
To supply adequately the fans and the heaters in cubicle component

Customer attachments
N/A

Load and capital costs
Total cost is $2,576.25. After remedy, the fan will work properly during summer tinme.

Detailed breakdown of starting dates and in-service dates for each project
In service September, 2010.

REVAMP NEW SERVICE AT SUBSTATION

Scope:
Replace transformer feeding Hydro One metering units

Objectives
Hydro one will be able to have the correct measurement

Customer attachments
N/A

Load and capital costs
Total cost is $22,389.75. After installation, Hydro One will be able to have the metering component working properly

Detailed breakdown of starting dates and in-service dates for each project
In service September, 2010.

POLES & FIXTURES

Scope

Each year CHEI performs inspection in order to identify which assets need to be removed from service in order to promote safety.

Objectives

Improve Safety and reliability with the removal of older assets.

Customer attachments

Poles and hardware were replaced at different locations.

Load and capital costs

Total capital cost for 2010 was $ 62,256.00

Detailed breakdown of starting dates and in-service dates for each project

Our replacement program started in April 2010 until the end of August 2010.

NEW SWITCH & ARRESTOR

Scope

Replace defective switch and arrestor on Ste-Marie Road

Objectives

Arresters are protective devices located on either side of power transformers. They're connected at the top to a line conductor and at the bottom to the ground. Surge arresters protect the transformers and other electrical gear from voltage surges caused by lightning or substation switching operations.

Customer attachments

14 customers attached to this switch will prevent power outage.

Load and capital costs

Capital cost $ 856.00

Detailed breakdown of starting dates and in-service dates for each project

Work performed in August 2010.

TRANFORMERS

Scope

Purchase the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure.

Objectives

Replace five defective transformers in order to prevent power outage

Customer attachments

About seventy customer supply by those specific transformer.

Load and capital costs

Total cost in 2010 is $ 28,328.00

Detailed breakdown of starting dates and in-service dates for each project

In service date during year 2010

NEW SERVICES

Scope

Installation of Overhead or Underground facilities for new customers.

Objectives

Respond rapidly to customers request for end use services. Connection of new overhead and underground service.

Customer attachments

New Services

Load and capital costs

Total cost in 2010 is $ 12,637.00.

Detailed breakdown of starting dates and in-service dates for each project

New connections are performed all year round upon customer requests.

OFFICE FURNITURE & EQUIPMENT

Scope
Office equipment to facilitate working conditions.

Objectives
Increase performance and provide adequate working tools. (i.e. furniture, screen tv,audio system)

Customer attachments
N/A

Load and capital costs
Capital cost in 2010: $3,013.00

Detailed breakdown of starting dates and in-service dates for each project
Expenditures done during 2010

COMPUTER EQUIPMENT

Scope
Replacement of 2 desktop computers.

Objectives
Provide the required equipment to perform regular CSR task and recognize the different software application requirements. Modify accordingly the server, the network service and working stations.

Customer attachments
N/A

Load and capital costs
Cost in 2010 $ 3,080.00

Detailed breakdown of starting dates and in-service dates for each project
In service date July & November 2010

COMPUTER SOFTWARE

Scope
New Billing System

Objectives
Perform required work with the latest technology and software applications

Customer attachments
N/A

Load and capital costs
Cost in 2010: $ 61,341.00

Detailed breakdown of starting dates and in-service dates for each project
In service: January 2010

2011Capital Expenditures

GL ACT #	2011CAPITAL PROJECTSDESCRIPTION	AMOUNT
1830	ST-JACQUES ROAD	$ 4 434.50
	BOURDEAU STREET	$ 3 557.50
	NOTRE-DAME	$ 6 585.00
	STE-MARIE	$ 3 519.52
	SUB TOTAL	$ 18 096.52
1835	REPLACEMENT EQUIPMENT	$ 4,224.23
1850	TRANSFORMER	$ 21 553.50
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$ 4,036.25
1915	FOLDER ,INSERTER, MAILING MACHINE	$ 14,694.00
1920	ADDITION NEW PRINTER	$ 2 319.90
1925	TRAINING NORTHSTAR ARREAR MANAGEMENT PROGRAM & SET UP	$ 1,500.00
1995	CONTRIBUTED CAPITAL	-($7 774.00)
	TOTAL	$ 58,650.40

POLES & FIXTURES

Scope

Each year CHEI performs inspection in order to identify which assets need to be removed from service in order to promote safety.

Objectives

Improve Safety and reliability with the removal of older assets.

Customer attachments

Poles and hardware were replaced at different locations.

Load and capital costs

Total capital cost for 2011 was $ 18,096.52

Detailed breakdown of starting dates and in-service dates for each project

Our replacement program started in May 2011 until the end of November 2011.

OVERHEAD BETTERMENT

Scope

Replace equipment when changing pole.(Switch, Lightning Arrestor. Polymeric Universal Post Insulator

Objectives

Improve Safety and reliability with the removal of older assets.

Customer attachments

About 30 customers are affected by these upgrades.

Load and capital costs

Capital cost $ 4,224.23

Detailed breakdown of starting dates and in-service dates for each project

Work performed in spring and fall 2011.

TRANFORMERS

Scope

Purchase the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure.

Objectives

Replace four defective transformers for repair to prevent power outage

Customer attachments

N/A

Load and capital costs

Total cost in 2011 is $ 21 553.50

Detailed breakdown of starting dates and in-service dates for each project

During year 2011

NEW SERVICES

Scope

Installation of Overhead or Underground facilities for new customers.

Objectives

Respond rapidly to customers request for end use services. Connection of new OH and UGservice.

Customer attachments

New services.

Load and capital costs

Total cost in 2011 is $ 4,036.25

Detailed breakdown of starting dates and in-service dates for each project

New connections are performed all year round upon customer requests.

OFFICE FURNITURE & EQUIPMENT

Scope
Office equipment to improve work site conditions.

Objectives
Add new customer bill folder, inserter machine. In house billing, new contract with ORPC

Customer attachments
N/A

Load and capital costs
Capital cost in 2011: $14,694.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: September 2011

COMPUTER EQUIPMENT/ PRINTER

Scope
Add one new printer.

Objectives
Add one new printer.In house billing, new contract with ORPC

Customer attachments
N/A

Load and capital costs
Cost in 2011 $ 2 319.90

Detailed breakdown of starting dates and in-service dates for each project
In service date January 2011.

COMPUTER SOFTWARE/HARRIS

Scope
Obtain software for arrears management program

Objectives
Adequate tool in order to comply with OEB requirements.

Customer attachments
N/A

Load and capital costs
Cost in 2011: $ 1,500.00

Detailed breakdown of starting dates and in-service dates for each project
In service: April 2011

2012 Capital Expenditures

GL ACT #	2012 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1830	.POLE REPLACEMENT(ONE POLE REPLACEMENT)	$ 3 098.10
1845	BARRIER TRANFORMER - HYDRO VAC FOR DUCK	$ 5 841.00
1850	NEW TRANSFORMER AND REPLACEMENT	$ 36 088.00
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$ 5,074.00
1860	SMART METER DEPLOYMENT	$ 310 212.00
1860	STRANDED METER	-$(79 072.00)
1940	SMART METER TOLL DEPLOYMENT	$ 4205.00
1920	NEW COMPUTER	$ 2,745.57
1995	CONTRIBUTED CAPITAL	-$(1 600.00)
	TOTAL	$ 286 591.67

POLES & FIXTURES

Scope

Each year CHEI performs inspection in order to identify which assets need to be removed from service in order to promote safety.

Objectives

Improve Safety and reliability with the removal of older assets.

Customer attachments

Poles and hardware were replaced at different locations.

Load and capital costs

Total capital cost for 2012is $ 3,098.10

Detailed breakdown of starting dates and in-service dates for each project

Our replacement program started in August 2012..

BARRIERS FOR PADMOUNT TRANSFORMER

Scope

Installed barrier around a transformer.

Objectives

Install adequate barriers to prevent damage to transformers that are located in areas open to vehicular traffic

Customer attachments

15 customers are affected by this transformer.

Load and capital costs

Capital cost $ 942.50

Detailed breakdown of starting dates and in-service dates for each project

In service date: August 2012.

HYDRO VAC -LOCATE DUCT DIP POLE-4TH FEEDER

Scope
Preparing installing a fourth feeder underground

Objectives
Build the u/g line according to CHEI & ESA requirements.

Customer attachments
N/A

Load and capital costs
Cost 2012: $4 898.50

Detailed breakdown of starting dates and in-service dates for each project
In service date: June 2012.

TRANFORMERS

Scope
Have the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure. Replace existing apparatus to prevent interruptions

Objectives
Replace defective transformer for repair to prevent power outage and order 3 - 167 kva pole mount

Customer attachments
N/A

Load and capital costs
Total cost in 2012 is $ 36 088.00

Detailed breakdown of starting dates and in-service dates for each project
During year 2012

NEW SERVICES

Scope
Installation of Overhead or Underground facilities for new customers.

Objectives
Respond rapidly to customers request for end use services. Connection of new OH and UGservice.

Customer attachments
New services.

Load and capital costs
Total cost in 2012 is $ 4,389.50

Detailed breakdown of starting dates and in-service dates for each project
New connections are performed all year round upon customer requests.

COMPUTER EQUIPMENT

Scope
Provide adequate working equipment.

Objectives
Provide tools to management to perform regular tasks. Computer desk with chair

Customer attachments
N/A

Load and capital costs
Cost in 2012 $ 2,745.47

Detailed breakdown of starting dates and in-service dates for each project
In service date: February 2012.

2013 Capital budget

GL ACT #	2013 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1820	GROUNDY STUDY SUBSTATION	$10 000.00
	ADD NEW SWITCHING CABINET 4TH FEEDER	$52 400.00
	SUB TOTAL	**$62 400.00**
1830	REPLACE POLES, FIXTURES AS PER ASSET MANAGEMENT PLAN	
	NOTRE-DAME STREET REPLACE 2 POLES	$10 400.00
	BOURDEAU CRESCENT REPLACE 1 POLE	$4 200.00
	ST-JACQUES ROAD REPLACE 2 POLES	$ 3 650.00
	BRISSON STREET REPLACE ONE POLE	$ 3 000.00
	NOTRE-DAME STREET (DAMAGE POLE)	$ 7 800.00
	SUB TOTAL	**$29 050.00**
1830	STE-THÉRÈSE STREET 4T FEEDER	$54 800.00
1835	STE-THÉRÈSE STREET 4T FEEDER	$58 750.00
1845	UG CABLE SUBSTATION TO STE-THÉRÈSE	$52 400.00
1850	TRANSFORMERS FOR REPLACING AND NEW SERVICES	$12 000.00
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$5 000.00
1915	CELL PHONE & EQUIPMENT	$1,500.00
1920	COMPUTER EQUIPMENT AND HARDWARE BATTERY BACK-UP	$1 500.00
1925	HARRIS SOFTWARE MOE STANDARD BILL PRINT	$25 000.00
1925	ANTIVIRUS PROTECTION	$1 500.00
1995	CONTRIBUTED CAPITAL	-$(8000.00)
	TOTAL	$295 900.00

GROUNDING STUDY -ACTUAL SUB-STATION LOCATION

Scope
Revised a grounding and calculation study at actual substation.

Objectives

In reference with IEE STD 80-2000 - Ontario Hydro Grounding Guide 1994- ESA Bulletin 36-10-16 - OESC: Rules 30-302-36-310

Customer attachment
N/A.

Load and capital costs
Cost 2013: $ 10,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: during 2013

INSTALLED - 4TH FEEDER SWITCH

Scope
Installing new 4th feeder switch on existing sub-station

Objectives

To be prepare for the future growth in 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system

Customer attachments
800 customer will be connected to this feeder.

Load and capital costs
Total estimated cost in 2013is $ 52 400.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: during 2013

POLE REPLACEMENT

Scope

As per OEB requirements, establish a comprehensive Asset Management Plan and replace existing aging assets.

Objectives

Improve Safety and reliability with the removal of older assets and replace damage pole.
Follow the Asset Management Plan and perform required replacement of aging assets.

Customer attachments

Our entire customer base.

Load and capital costs

Estimated Cost in 2013: $ 29 050.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: During 2013.

POLE REPLACEMENT-STE-THERÈSE -4TH FEEDER

Scope

Installing new pole to add the 4th feeder

Objectives

To be prepare for the future growth in 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system

Customer attachments

800 customer will be connected to this feeder.

Load and capital costs

Total estimated cost in 2013is $ 54 800.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: during 2013

CONDUCTORS AND DEVICES

Scope
Installing new primary cable to be use as 4th feeder

Objectives

To be prepare for the future growth in 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system

Customer attachments
800 customer will be connected to this feeder.

Load and capital costs
Estimated Capital cost in 2013 is $58,750.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013.

UNDERGROUND CABLE FROM SUBSTATION TO STE-THÉRÈSE

Scope
Installing underground cable to be used as 4th feeder.

Objectives

To be prepare for the future growth in 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system

Customer attachments
800 customer will be connected to this feeder.

Load and capital costs
Estimated cost in 2013 is $ 52,400.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013

TRANFORMERS

Scope
Purchase the required transformation for future addition on our distribution system and/or replacement of transformers in case of failure.

Objectives
Replace transformer for repair to prevent power outage

Customer attachments
Our entire customer base.

Load and capital costs
Estimated cost in 2013 is $ 12,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: 3 phases transformers Spring 2013

Subdivision transformers: during 2013

NEW SERVICES

Scope
Installation of Overhead or Underground facilities for new customers.

Objectives
Respond rapidly to customers request for end use services. Connection of new OH and UG service.

Customer attachments
New services.

Load and capital costs
Estimated cost in 2013 is $ 5,000.00

Detailed breakdown of starting dates and in-service dates for each project
New connections are performed all year round upon customer requests.

OFFICE FURNITURE & EQUIPMENT

Scope
Provide adequate working equipment.

Objectives
Upgrade cell phone and office equipment

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013: $ 1 500.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013

COMPUTER EQUIPMENT BATTERY BACK-UP

Scope
Provide adequate working equipment.

Objectives
Provide tools to management to perform regular tasks. Protect actual hardware as required by our service provider

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013 $1 500.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2013.

COMPUTER SOFTWARE /MOE STANDARD BILL

Scope
To follow the direction of the Ministry of Energy

Objectives
Standard bill for customer -Time of use rate

Customer attachments
N/A

Load and capital costs
Estimated cost in 2013: $ 25,000

Detailed breakdown of starting dates and in-service dates for each project
In service: During 2013

2014 Capital budget

GL ACT #	2014 CAPITAL PROJECTS DESCRIPTION	AMOUNT
1830	REPLACE POLES, FIXTURES AS PER ASSET MANAGEMENT PLAN	
	ST-JACQUES ROAD 3 SPAN DEAD END POLE	$ 9 850.00
	1179 ST-JACQUES REPLACE ONE POLE	$ 5 500.00
	65 FORGET REPLACE ONE POLE	$ 5 400.00
	SUB TOTAL	**$ 20 750.00**
1830	CLOUTIER STREET 4TH FEEDER	**$ 39 470.00**
1835	CLOUTIER STREET 4TH FEEDER	**$19 375.00**
1845	PARC RICHELIEU 4TH FEEDER	$ 98 000.00
	PATENAUDE SUBDIVSION (100 UNITS)	$ 120 000.00
	BRISSON PROJECT OLIGO (50 UNITS)	$ 60 000.00
	DOMAINE VERSAILLE PHASE (50 UNITS)	$ 60 000.00
	MAURICE LEMIEUX NEW YORK CENTRAL PROJECT (50 UNITS)	$ 60 000.00
	SUB TOTAL	**$ 398 000.00**
1850	TRANSFORMERS FOR THE PROPOSED SUBDIVISION AND LDC NEED	$ 87 500.00
1855	NEW O.H. AND U.G SERVICES MATERIAL AND LABOUR	$ 4 000.00
1860	SMART METERS (300)	$30 500.00
1925	HARRIS VERSION 6.4 UPGRADE	$ 20 000.00
	HARRIS - CUSTOMER CONNECT	$ 15 000.00
	SUB TOTAL	$ 35 000.00
1995	CONTRIBUTED CAPTAL	$-(160 000.00)
	TOTAL	$ 474 595.00

POLES & FIXTURES

Scope

As per OEB requirements, establish a comprehensive Asset Management Plan and replace existing aging assets.

Objectives

Improve Safety and reliability with the removal of older assets.
Follow the Asset Management Plan and perform required replacement of aging assets.

Customer attachments

Our entire customer base.

Load and capital costs

Estimated Cost in 2014: $ 20,750.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: During 2014.

POLES & FIXTURES -CLOUTIER STREET 4T FEEDER

Scope

Installing new pole to add the 4th feeder

Objectives

To be prepare for the future growth in 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system

Customer attachments

800 customer will be connected to this feeder.

Load and capital costs

Total estimated cost in 2014 is $ 39 470.00

Detailed breakdown of starting dates and in-service dates for each project

In service date: during 2014

CONDUCTORS AND DEVICES -CLOUTIER STREET 4TH FEEDER

Scope
Installing new primary cable to be use as 4th feeder

Objectives

To be prepare for the future growth in 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system

Customer attachments
800 customer will be connected to this feeder

Load and capital costs
Estimated Capital cost in 2014is 19 375.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014.

UNDERGROUND CONDUCTORS AND DEVICES -4TH FEEDERS

Scope
Installing underground cable to be use as 4th feeder.

Objectives

To be prepare for the future growth in 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system
Customer attachments
800 customer will be connected to this feeder

Load and capital costs
Estimated Capital cost in 2014 is $98,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014.

UNDERGROUND CONDUCTORS AND DEVICES

Scope
After discussion with the municipality there will be four new project in CHEI service area

Objectives
Respond to the entrepreneur's request if in fact request for new subdivision arise and sufficient transformers.

Customer attachments
New residential subdivision.Vacant land.

Load and capital costs
Estimated cost in 2014 is $ 300,000.00 (capital contribution will be required from the entrepreneur)

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014

TRANFORMERS

Scope
After discussion with the municipality there will be four new project in CHEI service area

Objectives
Respond to the entrepreneur's request if in fact request for new subdivision arise and sufficient transformers.

Customer attachments
New residential subdivision.Vacant land.

Load and capital costs
Estimated cost in 2014 is $ 87,500.00 (capital contribution will be required from the entrepreneur)

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014

NEW SERVICES

Scope
Installation of Overhead or Underground facilities for new customers.

Objectives
Respond rapidly to customers request for end use services. Connection of new OH and UG service.

Customer attachments
New services.

Load and capital costs
Estimated cost in 2014 is $ 4 000.00

Detailed breakdown of starting dates and in-service dates for each project
New connections are performed all year round upon customer requests.

METERS

Scope
New Smart meters in order to respond to ongoing demand.

Objectives
Have the proper Smart meter available for new residential and commercial customer. (Gen<50 KW).

Customer attachments

N/A

Load and capital costs
Estimated cost in 2014 is $ 30,500.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014.

COMPUTER SOFTWARE -HARRIS VERSION 6.4

Scope
Provide adequate working equipment.

Objectives
Provide tools to management to perform regular tasks. Protect actual hardware as required by our service provider

Customer attachments
N/A

Load and capital costs
Estimated cost in 2014 $20,000.00

Detailed breakdown of starting dates and in-service dates for each project
In service date: During 2014.

COMPUTER SOFTWARE/CUSTOMER CONNECT

Scope
Provide tools to our customers to promote conservation.

Objectives
CHEI will provide a CUSTOMER CONNECT tool to its customers to help and promote energy conservation

Customer attachments
N/A

Load and capital costs
Estimated cost in 2014: $ 15,000

Detailed breakdown of starting dates and in-service dates for each project
In service: During 2014

E2.T2.S5 EXPLANATION OF EXPENSES OVER THE MATERIALITY THRESHOLD

The following projects are noted to be over the materiality threshold of $50,000 and therefore warrant further explanation

2010

1830 – Poles and Fixtures in the; $62,256

CHEI has replaced poles on Brisson Street ($18,000.00), Bourassa Street ($22,000), LaPalme Street ($16,000 and Centennaire Street ($6,252.00). CHEI has been monitoring its poles on a yearly basis and found that a substantial number of poles were were in need of replacement which can significantly impact the safety and reliability of the distribution system. Poles are prioritized for replacement based upon age, condition and potential adverse impact on the reliability of the distribution system.

1925-Computer Software; $61,341

This expenditure was approved in CHEI's last Cost of Service application. At the end of August 2006 Advanced was purchased by Harris which resulted in the abandonment of the Advance CIS System. The utility purchased Harris' NorthStar CIS system at the cost of $61,256. Further details can be found in EB-2019-0132.

2012

1860 – Smart Meters

CHEI filed a stand-alone smart meter application in the fall of 2012. As indicated in Guideline G-2011-0001 "*A distributor can rely on the order obtained in a stand-alone proceeding in subsequent rate proceeding(s) as evidence that the Board has reviewed and approved the underlying costs. In its next cost of service application, the distributor should include the approved smart meter capital (and associated accumulated* *depreciation) and annual operating costs in its application and seek to include the above in its rate base and revenue requirement."*

In accordance with the above guidelines, CHEI has transferred its Smart Meter Capital related expenditures in the amount of 310,212 in its Rate Base, more specifically in 2012 when the bulk of the smart meters were installed. The decision and order is filed as an Appendix to this Exhibit.

2013

Preamble

The utility anticipates load growth in the next few years due to the building of several subdivions. At the time of this application only one subdivision is planned. In anticipation of this additional load growth, CHEI hired Stantec to conduct a System Load-Flow and Optimization Study. This study is appended at the end of this Exhibit. As indicated by Stantec in the its report, the 44kV is running at near maximum capacity and at this point, cannot accommodate future load. The report sets out various options to remedy the situation. The most appropriate option was to add a 4^{th} feed to reduce emergency switching overload conditions and the installation of this 4^{th} feeder along the routing of the 3^{rd} feeder, with the bulk of new load in the vicinity of the 3^{rd} feeder installed on the new 4^{th} feeder. Much of the planned capital expenditures in 2013 and 2014 are linked to these upgrades in anticipation of the new subdivision.

1820-Distribution Station Equipment - Normally Primary below 50 kV; $62,400

These cost are operational costs related to the new 4^{th} feeder and can be broken down as;

- 1-15 kV Fused Loadbreak Switch Encolsure - $33,275
- 1 Set Current Transformers – 200/5 Ratio - $6,200
- 1 Set Integrated Ammeters with resettable Peak Indicators - $7,650
- Switchgrea Commissioning - $3500
- Electrician Subcontractor - $1,775
- Grounding and calculation study - $10,000

1830- -Poles, Towers and Fixtures

- Pole #3: Class 3 Pole ($1,485) Material for pole reframing ($3,000) and labour ($4,400)
- Pole #5: Class 3 Pole ($1,485) Material for pole reframing ($4,200) and labour ($4,400)
- Pole #7: Class 3 Pole ($1,485) Material for pole reframing ($3,300) and labour ($4,200)
- Pole #9: Class 3 Pole ($1,485) Material for pole reframing ($3,200) and labour ($4,800)
- Pole #12; Class 3 Pole ($1,485) Material for pole reframing ($4,200) and labour ($6,000)

1835-Overhead Conductors and Devices; $58,750.

These cost are in preparation of future load growth beyond 2015 (south of Castor River 1500 customers) and reduce line lost on distribution system. The breakdown of the capital costs are as such;

- Pole #1: Material for pole reframing ($4,850) and labour ($4,500)
- Pole #2: Material for pole reframing ($5,665) and labour ($5,000)
- Pole #4: Material for pole reframing ($1,850) and labour ($4,500)
- Pole #6: Material for pole reframing ($3,000) and labour ($4,000)
- Pole #8: Material for pole reframing ($3,200) and labour ($3,800)
- Pole #10: Material for pole reframing ($1,850) and labour ($3,200)
- Pole #11: Material for pole reframing ($1,850) and labour ($3,200)
- Pole #13: Material for pole reframing ($790) and labour ($1,317)

- Conductor – 3x640 meters of 336.4 KCML = 1920m at 3.90/m $7,488+$3,950

1845-Underground Conductors and Devices; $52,400

These cost are operational costs related to the new 4th feeder and can be broken down as;

- 13x210 meters of 500MCM – Aluminium High Voltage Primary underground cable - $39,500
- Cable Termination (6) for High Voltage Cable - $7,900
- Cable Commissioning – 5,000

2014

1845-Underground Conductors and Devices; $398,000

The only costs above the materiality threshold are related to the connection of 250 houses to the distribution system. CHEI estimates that the connection cost per house will be $1,200.

Parc Richelieu 4th feeder connection; $98,000

Patenaude Subdivision (100 units @ $1,200); $120 000.00

Brisson Project Oligo (50 units); $60 000.00

Domaine Versaille (50 Units) $ 60 000.00

New York Central Project (50 Units) $60 000.00

E2.T2.S6 CAPITALIZATION AND OTHER ASSET RELATED POLICIES

CHEI records capital assets at cost in accordance with Canadian Generally Accepted Accounting Principles as well as guidelines set out by the Ontario Energy Board, where applicable.

All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits. The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. CHEI does not currently capitalize interest on funds used for construction.

CHEI's adherence to the capitalization policy can be described as follows;

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.
- General Plant items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.
- With respect to vehicles, please note that CHEI does not own any vehicles.
- Maintenance services are contracted out.

Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, are not, nor have they ever been capitalized.

E2.T2.S7 ASSET MANAGEMENT PLAN

CHEI's Asset Management Plan is presented at the next section

Cooperative Hydro Embrun Inc.

Asset Management Plan
January 2013

Table of Contents

1 INTRODUCTION

Cooperative Hydro Embrun Inc.'s Asset Management Plan is designed to present the utility's approach to capital expenditure planning. This includes documentation of its asset management process that supports its future capital expenditure plan while detailing its historical activities. It recognizes its responsibilities required in order to provide its customers with reliable service that is viewed as excellent value for money, by ensuring that its asset management activities maintain a focus on customers, both operational and cost effectiveness, public policy responsiveness and financial performance.

Asset management requires a thorough understanding of the characteristics and condition of infrastructure assets, as well as the service levels expected from them. It also involves setting strategic priorities to optimize decision-making about when and how to proceed with investments.

Please note that the information and statements made in this Asset Management Plan are prepared on the assumptions, projections, forecasts and represents CHEI's' intentions and opinions at the date of preparation. Circumstances will change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and CHEI's may, at a later date, decide to take different actions from those it currently intends to take as expressed in this Asset Management Plan.

2 PERIOD COVERED

The planning horizon of the Asset Management Plan is from 2014 to 2024. It is intended that the Asset Management Plan will be a living document that will be reviewed on a periodic basis.

The planning horizon extends for a twenty (10) year period. The main focus of the plan concentrates on both 2013 and 2014 as budgets for these years have been developed. The Inspection and Condition Assessment is based on a planning horizon of twenty (10) years and predicts the sustainment of assets through to 2024.

It is very likely that new developments, that are not identified here, will arise at any given time even in the short term.

3 PURPOSE, OBJECTIVES AND ACCOUNTABILITY

Purpose

The purpose of this Asset Management Plan is to define CHEI's approach to its core business which is to supply reliable electrical services to its customers at a reasonable cost. This requires:

- Maintains service levels that will meet customer, community, and regulatory expectations for its distribution system.
- Understands what levels of distribution system capacity, reliability, and security of supply will be required both now and in the future, and what issues will drive these requirements.
- An understanding of the age, condition and performance of its assets
- Documenting its inspection practices in accordance with the Distribution System Code
- Forecasting and planning for the future growth of load customers and renewable generation facilities
- Recognizing and addressing constraints in the current distribution system and anticipating future capacity requirements
- Demonstrating that the asset management process recognizes the above items and prioritizes projects to accommodate customers and system requirements
- Developing a capital expenditure plan that anticipates the future growth, capacity and performance of the distribution system while remaining flexible to accommodate the unknown requirements of its customer base

Objectives

Prudent capital investment plans and operations and maintenance budgets reflect current priorities and anticipate future spending.

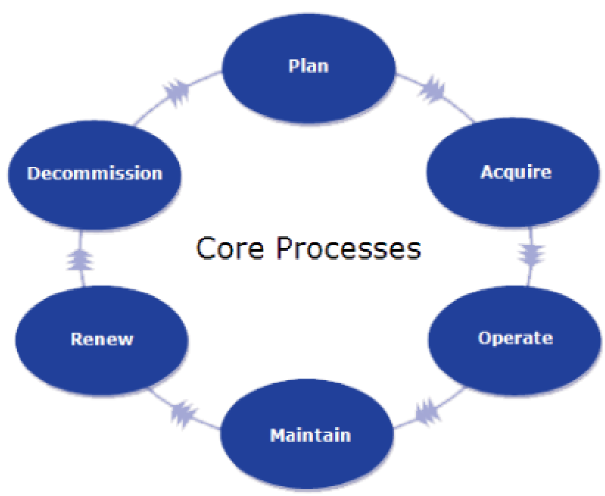
CHEI's employs good utility practices to manage and operate its distribution system. Its Asset Management Strategy prioritizes work to achieve the following objectives:

- Maintain its reliability performance
- Meet regulatory obligations
- Address significant environmental risks
- Replace end-of-life assets
- Improve operational efficiency

Accountability

The following organizational chart includes the key positions that are accountable for the management of the distribution system assets, the asset management data and implementation of the Asset Management Plan including the allocation and control of the capital expenditures

The following presents the typical process that CHEI follows when managing its assets.



4 UTILITY SPECIFICS AND ASSETS

CHEI relies on approximately 27 km of circuits and 288 transformers to re-deliver approximately 29,500,000 kWh of energy and 14,000 kW of power to approximately 2,000 customers. CHEI's circuits include approximately 15 km of overhead lines and 12 km of buried conductor. CHEI is entirely embedded within Hydro One Networks Inc.'s low voltage system. There are no other neighbouring electricity distribution utilities. The Town of Embrun is also served with natural gas delivery service. Of the approximate 2000 customers situated in the Town of Embrun, 70% of the customers are residential, 8% are commercial. The rest is attributable to Street Lighting and Unmetered Scattered Load.

CHEI's distribution system consists of the following major components.

- Poles – 760
- Overhead Transformers – 183
- Single Phase Pad-mount Transformers – 107
- Three Phase Pad-mount Transformers – 5
- Kilometers of 3 Phase Circuits – 12
- Kilometers of 1 Phase Circuits – 14

Being a smaller utility with a fairly small service area allows CHEI's to be well informed on the condition of its assets and uses management's operating judgment and experienced contractors to replace plant cost effectively when it can no longer be maintained effectively or safely.

In preparation for its 2014 Cost of Service application, CHEI performed a comprehensive internal assessment of its distribution system. This provided updated information to accurately populate the data in its reporting system and served as a new baseline for the annual patrol inspections required by the Distribution System Code.

In addition CHEI's reviewed the status and age of the major components, within its distribution system. These primary system components were:

- Poles
- Cables
- Distribution Transformers
- Switches/Protective Devices
- Pad-Mounted Switchgear
- Inspection of the Underground Distribution System
- Inspection of Substations

The assessment along with the utilities maintenance program is described in the next section.

Substation

The main equipment within CHEI's 44kV substation is listed below.

System Component	*Rating*	*Ampacity @ 8.32kV (44kV)*
44kV Primary Switch	Continuous Amps	3173A (600A)
44kV Primary Fuses S&C Electric SMD-1A, 175E Standard Speed TCC 153-1	Continuous Amps Daily 8 hour peak Emergency 8 hour peak	1015A (192A) 1037A (196A) 1185A (224A)
44,000/8,320V Transformer Delta/Wye (Grnd.), Z = 6.4% 7.5/10MVA, ONAN/ONAF	Continuous Amps ONAN rating Continuous Amps ONAF rating	520A (98A) 693A (131A)
8.32kV Secondary Switchgear Rated Voltage15kV, 1200A, 95kV BIL	Continuous Amps	1200A
8.32kV Feeder Switches, S&C Alduti	Continuous Amps	600A
8.32kV Feeder Fuses S&C SM-5, 300E Standard Speed TCC 153-1	Continuous Amps Daily 8 hour peak Emergency 8 hour peak	300A 306A 320A

In the spring of 2011, Stantec was hired by CHEI to conduct a Load Flow Study on the utility's substation. The objectives of the study were to;

- Determine the acceptability of the system with current and future load growth, including loading that has been recently defined for the next 10 year period. (2010-2020)
- Find out whether the system would operate acceptably under emergency situations.
- Optimizing the system arrangement (cable size, load balancing, open points…) to optimize losses, maximize voltage support and distribute loading evenly.
- To determine the optimal placement of a future transformer to allow distribution redundancy and peak loading support.

The report is appended to the back of this Asset Management Plan.

Poles

The table below shows how many poles need to be replaced per year based on when the poles were originally installed. Pole replacements identified in red have been budgeted for in CHEI's 2014 Cost of Service application. Details are presented at Appendix

Poles Replacement Schedule

Replacement Year	Count	Replacement Year	Count	Replacement Year	Count	Replacement Year	Count
1999	4	2021	20	2031	26	2043	12
2004	2	2022	12	2032	45	2044	3
2011	4	2023	11	2033	6	2045	10
2012	1	2024	32	2034	25	2046	7
2015	4	2025	31	2035	4	2047	8
2016	1	2026	17	2036	7	2048	9
2017	1	2027	22	2037	2	2049	8
2018	1	2028	110	2038	19	2051	4
2019	17	2029	83	2041	16	2052	5
2020	7	2030	8	2042	7		

Transformers and Switches

The table below shows that no transformers or switches are in need of replacement until 2012 and 2026 respectively.

Transformer Replacement Schedule

Replacement Year	Count	Replacement Year	Count
2021	1	2034	2
2023	14	2035	2
2024	6	2036	2
2025	1	2037	46
2026	8	2045	2
2027	37	2046	4
2028	25	2047	18
2029	22	2048	38
2030	14	2049	24
2031	5	2051	8
2032	9	2052	14
2033	24		

Switch Replacement Schedule

Replacement Year	**Count**
2027	8
2028	1
2029	2
2030	6
2031	1
2032	5
2033	6
2034	1
2037	4
2045	2
2046	2
2052	2

5 INSPECTIONS AND CONDITION ASSESSMENTS

The OEB has documented its Minimum Inspection Requirements (Appendix C of the Distribution System Code, "DSC") that outlines minimum inspection standards and inspection intervals of the distribution system. The Minimum Inspection Requirements further define Patrol Inspection and provide a list of major assets within CHEI's distribution system to be patrolled. The assets applicable to CHEI's include:

- Poles and Supports
- Hardware and Attachments
- Conductors and Cables
- Switching & Protective Devices
- Distribution Transformers
- Substations
- Vegetation
- Civil Infrastructure

The following sections describe CHEI's regular inspection program that is consistent with the DSC. The purpose of such an inspection program is to determine asset condition, identify any risk to safety, reliability and/or the environment, and subsequently addresses findings through prudent capital, operations and maintenance expenditures, as necessary.

Inspection of the Overhead Distribution System

The overhead portion of the distribution system is comprised primarily of poles, conductors, distribution transformers and protective devices. These assets are inspected as briefly described in the sections to follow;

POLES/SUPPORTS/ CROSS ARMS

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code as good utility practice. CHEI conducts pole inspections annually to determine when poles need to be replaced.

Pole Replacements are undertaken for the following different reasons:

- Structural damage
- Taller or different class of pole required
- Health and safety hazard to the public and employees
- Pole damaged
- Line rebuilds and ESA compliance

CHEI's current pole inspection program is based on a comprehensive assessment performed in 2012. All poles within the geographic areas were inspected such that all poles were assessed by year-end. CHEI's utilized and external contractor to document the attributes of each pole (e.g. age, height, class, etc.), establishing a baseline of attribute information. Additionally, the contractor provided an assessment of each pole's condition and subsequently made recommendations for pole replacements based on these attributes (primarily age) and condition, as per annual inspection process.

Today, there are 404 wood poles within CHEI's distribution system. Approximately one-third of all wood poles are inspected on an annual basis, thereby completing inspection of all such poles within the distribution service area on a three year cycle.

CABLES

CHEI's closely monitors its cable failure rates and initiates cable replacement projects as part of its annual capital budgeting process.

CHEI's annual inspections also identifies the following hazard

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Insulation fraying on secondary especially open-wire

HARDWARE AND ATTACHMENTS

CHEI conducts hardware and attachments inspections annually to determine when they need to be replaced. Replacements are undertaken for the following different reasons:

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

DISTRIBUTION TRANSFORMERS

Inspection of overhead distribution transformers is an integral component of CHEI's predictive maintenance practice. It identifies conventional deficiencies such as rusted or leaking transformers. Infra-reds testing are also performed regularly to identify overheating transformers.

SWITCHES/PROTECTIVE DEVICES

Inspection of overhead switches and other protective devices is an integral component of CHEI's predictive maintenance practice. It identifies conventional deficiencies such as loose, flashed or old switches, each of which may deteriorate the condition of the asset, pose a risk to safety, or reduce reliability of the overhead distribution system.

CHEI meets the switch inspection requirements under the Minimum Inspection Requirements of the Distribution System Code. Switches are devices that allow or disallow the conductivity of high voltage conductors. They are available in single phase solid or fused configurations and three phase applications involving load break and air break. Fused cut-outs accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused switches (cutouts) are inspected during yearly patrol process. Switch Replacements are undertaken for the following reasons:

- Mechanical or electrical failure
- Vehicle accidents, lightning strikes
- New customer requirements
- Line rebuilds or circuit reconfigurations

Inspection of the Underground Distribution System

The OEB's Minimum Inspection Requirements, in addition to listing major overhead distribution system assets, also identifies those major assets specific to the underground distribution system; including and applicable to CHEI's are: distribution transformers, switches and protective devices, cables, civil infrastructure and vegetation. As with its overhead system, CHEI's inspection cycles of these assets is based, in part, on its geographical areas but also on the category of distribution asset.

Substation Inspection and Maintenance

CHEI's distribution system includes one Distribution Station. Power is delivered from a single Transformer Station (TS) Chesterville, owned by Hydro One, with 110kV transformation to 12.4kV.

CHEI's performs an inspection and condition assessment of all its stations on an annual basis or as required. The inspection is performed by qualified contractors. The inspection includes an assessment of the following:

• Feeder Readings
○ Amperage on each phase
○ Voltage on each phase
○ Counter Reading
• Substation Monthly Readings
○ Total KWH
○ Maximum KW
○ Maximum KVA
• Transformers
○ Temperature
○ Oil Level
○ Leaks
• Vegetation
• Electrical Panel
• Receptacles and Light Switches
• Indoor & Outdoor Lighting Fixtures
• Battery Chargers and Batteries
• RTUs

• Cooling Fans
• Sump Pump
• Baseboard Heaters
• Station Lights
• Grounding

TRANSFORMER OIL ANALYSIS

Oil analysis is performed at each of CHEI's Municipal Station. Completed by a qualified contractor, the scope of gas analysis and oil testing as outlined in the contract includes the following:

Oil Tests:		Dissolved Gas Analysis:		Moisture In Oil:
Acid		Hydrogen		Percentage Moisture by Dry Weight
Relative Density		Oxygen		Aging Factor
Dielectric Breakdown		Nitrogen		Percentage Moisture Saturation
Interfacial Tension		Methane		
Specific Gravity		Carbon Monoxide		
Visual Condition		Carbon Dioxide		
Colour		Ethane		
Water Content		Ethylene		
Power Factor		Acetylene		
Neutralization No.				

Oil samples obtained by the contractor are subsequently sent to a laboratory for testing; the results of individual transformer oil analysis are provided to CHEI's. Also provided is an informal report of the results, highlighting any anomalies/concerns that may exist and corresponding recommendations for remediation.

RELAY TESTING

Testing of both electrical and mechanical relays is performed on a three year cyclical basis by a qualified contractor at each of the Municipal Stations. CHEI's provides the relay settings to the contractor and relies on the contractor's expertise in performing the testing. Critical deficiencies are reported immediately and CHEI's addressed immediately. Non-critical deficiencies are subsequently remediated through condition-based maintenance.

AS IDENTIFIED DURING INSPECTIONS

Condition-based maintenance of Municipal Stations is performed during or following the monthly inspection and condition assessment or as identified within the predictive maintenance program.

FOLLOWING TRANSFORMER OIL ANALYSIS

Recommendations for remediating anomalies or concerns identified during transformer oil analysis as presented to CHEI's may include no action/observing, re-testing or replacing, for example. CHEI's generally follows the recommendations and implements those condition-based maintenance recommendations or capital expenditures and within the recommended timeline.

FOLLOWING RELAY TESTING

During relay testing, critical deficiencies are reported and addressed immediately.

Meters

CHEI's installed Smart Meters throughout its service territory between 2009 and 2011 when the Provincial Government mandated the replacement of the electromechanical billing meters with the new Smart Meter and Advanced Meter Infrastructure ("AMI") two-way communication system.

CHEI's has used a Typical Useful Life (TUL) of fifteen (15) years for Smart Meters.

LINE CLEARING AND TREE TRIMMING

Vegetation and Right of Way control is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Where overhead hydro lines are in the proximity to trees, regular trimming is required to prevent vegetation form contacting energized lines and inflicting.

- Interruption of power due to short circuit to ground or between phases
- Damage to conductors, hardware and poles
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles and trees
- Danger of electric shock potential from electricity energizing Vegetation

Tree contacts are a major cause of distribution system outages and momentary interruptions for CHEI's customers. CHEI's has a regular line clearing and tree trimming maintenance program. This program cycles through the service territory on a three year basis. In 2011 the program was changed to an area by area program. Currently the schedule is to complete each area at least once in a three year period subject to change based on conditions found.

6 CAPITAL PLANNING

Managing Aging Infrastructure

Distribution systems are growing older. In many service areas, significant portions of the equipment and facilities in place date from the economic boom during the heady growth periods of the 1960s. Equipment that is 50+ years of continuous operation is still in service in many areas.

For almost all electrical equipment, as it stays in service and ages, its potential failure rate increases, slowly year by year, and eventually reach their respective service life limits and begin to fail. When this happened, service reliability plummet, replacement costs skyrocket, and the utility's business performance suffers.

CHEI is of the opinion that although age is in many ways the best overall proxy one has for the long-term effects of condition and deterioration, condition is the real issue. Some units of equipment might deteriorate so that condition is poor after only 40 years. Another unit, aged 70 years, might be in that same condition. The utility should be equally concerned about each.

Even among the oldest equipment, a majority might still be in serviceable condition and can provide years of good service. The utility's best course is to do what it can to find the bad actors and the questionable equipment and replace only those pieces of the system, continuing into the future each year with a system that is old but in a managed condition. Thus, some combination of on-going testing, tracking, mitigation of continued deterioration and the effects of failures, and pro-active replacement and refurbishment of deteriorated equipment, will be needed in the long run.

Such preventative actions will not make the problem go way, they will just control it to an "optimum" level, a stable, sustainable point at which equipment in service continues to age and the utility continues to test, maintain, and service replace equipment sparingly but in a targeted manner, with overall cost is kept at a minimum.

Project Identification

Capital projects are identified through CHEI's intimate knowledge of the system gained by experience, through inspection of the system and subsequent data analyses, as noted above.

Projects are identified for a ten-year period such that they may be prioritized to achieve asset management objectives.

Development of Annual Capital Budget

The budget development process plays an important role to CHEI's as it puts capital (and operational) plans into a financial plan, outlining its goals and asset management objectives.

With respect to all distribution assets, the General Manager reviews the capital planning to identify distribution projects that have been previously prioritized and are scheduled to be completed in the upcoming budget year. These projects are reviewed to determine whether priorities have changed. A project may become lower priority due to newly proposed or non-discretionary projects. Alternatively, a project may become higher priority in light of new information.

Following the review, those distribution projects identified as high priority are estimated and proposed within the annual capital budget.

3 year forecast of capex

ACCOUNT NUMBER		2015	2016
1820	Distribution Station Equipment	$ 18,000.00	$ 20,000.00
LAST 5 YEARS AVERAGE $17 600.00			
1830	Poles, Towers & Fixtures	$ 30,000.00	$ 31,000.00
LAST 5 YEARS AVERAGE $32 650.00			
1835	Overhead Conductors and Device	$ 23,000.00	$ 26,000.00
LAST 5 YEARS AVERAGE $19 166.00			
1845	Underground Conductors & Devices	$ 95,000.00	$ 115,000.00
LAST 5 YEARS AVERAGE $91 430.00			
1850	Line Transformers	$ 40,000.00	$ 43,000.00
LAST 5 YEARS AVERAGE $37 700.00			
1855	Services	$ 6,200.00	$ 6,500.00
LAST 5 YEARS AVERAGE $6 150.00			
1860	Meters	$ 25,000.00	$ 30,000.00
LAST 5 YEARS AVERAGE $ 40 000.00			
1915	Office Furniture & Equipment	$ 3,500.00	$ 3,500.00
LAST 5 YEARS AVERAGE $3 800.00			
1920	Computer Equipment Hardware	$ 2,000.00	$ 2,000.00
LAST 5 YEARS AVERAGE $1 940.00			
1925	Computer Software	$ 22,000.00	$ 22,500.00
LAST 5 YEARS AVERAGE $21 600.00			
		$ 264,700.00	$ 299,500.00

7 DOCUMENTATION& DATA ANALYSES

Guidelines for Inspection and Maintenance Programs

There are several inspection and maintenance programs for which CHEI's has developed documented guidelines; for example, vegetation management and pad mount transformer inspection. Alternatively, CHEI's relies on the expertise of the contractor implementing the program and therefore documented guidelines may not be required. For all other inspection and maintenance programs CHEI's is currently developing or has plans to develop documented guidelines to provide direction and ensure consistency in executing the program and allowing for more consistent data reporting, analysis and prioritization of expenditures.

Information and Document Management

INSPECTION RECORDS

Inspection results are clear and well-documented, allowing for reliable information to be obtained on the condition of assets inspected.
An annual summary report of Inspections is used to schedule and track the Inspection Process of the Distribution System Assets.

MAINTENANCE RECORDS

Maintenance is largely driven by work orders, developed in CHEI's work order system.

REPORTING

Currently, data from the individual reports prepared on behalf of CHEI are reviewed to facilitate data analyses of the status, condition and operation of the distribution system and its assets. Utility Load Flow and evaluation reports are also prepared by Stantec on a regular basis. The report provides useful and critical loading information on the municipal substation.

E2.T2.S8 GREEN ENERGY ACT PLAN CAPITAL EXPENDITURES

CHEI's Green Energy Plan is presented at the next page.

Cooperative Hydro Embrun Inc.
Basic Green Energy Act Plan

2013

Contents

1.0 INTRODUCTION

The *Green Energy and Green Economy Act, 2009* ("the Act" or "GEA") was introduced in the Ontario legislature on February 23, 2009. Its intent was to expand renewable energy production and encourage energy conservation. Under the GEA, a number of feed-in tariff rates for different types of energy sources were created. Most notably, the microFIT program for small non-commercial systems under 10 kilowatts, and FIT, the larger commercial version which covers a number of project types with sizes into the megawatts. The objectives of the Act include the following;

- To stimulate energy conservation, through the establishment of programs and policies within the Ministry or such agencies as may be prescribed, load management and the use of renewable energy sources throughout Ontario;
- To encourage prudence in the use of energy in Ontario;
- To stimulate the planning and increase the development of infrastructure in Ontario, and
- To support planning and growth and building strong communities in Ontario.

Two other key elements of the Act include:

- To facilitate the implementation of a smart grid in Ontario; and
- To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

1.1 GEA Plan Guiding Principles

The Act requires that each LDC file a Green Energy Act Plan ("GEA Plan") with the Ontario Energy Board ("the OEB" or "the Board"), in a manner consistent with the requirements in the GEA. The plan filing will serve three main purposes:

1) To provide information to the Board and interested stakeholders regarding the readiness of a distributor's system to accommodate the connection of renewable generation, as well as the expansion or reinforcement necessary to accommodate renewable generation, and the development and implementation of "smart grid";

2) To provide evidence in rate applications for capital budget approvals related to infrastructure investments for renewable generation and smart grid, and the recovery of the resulting costs from ratepayers; and

3) To provide a basis, through the approval of a GEA Plan, by which the costs of certain investments will be the responsibility of the distributor under the DSC, and therefore possibly recovered through the provincial cost recovery mechanism set out in section 79.1 of the OEB Act.

The OEB has identified two types of Plans; the Basic GEA Plan and the Detailed GEA Plan. As a minimum, a Basic GEA Plan is required of all LDCs. A Detailed GEA Plan is required only for those distributors where:

a. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:
    i. *Are more than $100,000 and exceed 3% of the distributor's distribution rate base; and*
    ii. *Exceed $5,000,000.*

b. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid over five years:
    i. *Are more than $100,000 and exceed 6% of the distributor's distribution rate base; and*
    ii. *Exceed $10,000,000.*

Cooperative Hydro Embrun Inc. ("CHEI") does not meet the threshold for filing a Detailed GEA Plan and, as such, has prepared this Basic GEA Plan. The Basic GEA Plan includes requirements for:

1. A current assessment of the LDC's distribution system;
2. A planned approach (if required) to upgrading the distribution system to accommodate renewable generation; and
3. Proposed initiatives to enable the development of a "smart grid".

In accordance with the OEB's filing requirements under the *Green Energy and Green Economy Act, 2009,* CHEI has prepared this Basic Green Energy Plan ("GEA Plan"). The GEA Plan provides summary information about current demands from generation, a description of the current efforts to enable renewable generation and future plans to accommodate anticipated new connections.

1.2 Enabling Renewable Generation Connections - Overview

To ensure that renewable generation projects can be readily connected to the LDCs distribution system without undue delay is a major focus of the Act. To this end, LDCs are subject to the following requirements:

a. The licensee is required to provide, in accordance with such rules as may be prescribed by regulation and in the manner mandated by the market rules or by the Board, priority connection access to its transmission system or distribution system for renewable energy generation facilities that meet the requirements prescribed by regulation made under subsection 26 (1.1) of the Electricity Act, 1998.

b. The licensee is required to prepare plans, in the manner and at the times mandated by the Board or as prescribed by regulation and to file them with the Board for approval for;

i. the expansion or reinforcement of the licensee's transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and
ii. the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

c. The licensee is required, in accordance with a plan referred to in Paragraph 2, that has been approved by the Board or in such other manner and at such other times as mandated by the Board or prescribed by regulation;
    i. to expand or reinforce its transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and
    ii. to make investments for the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

2.0 CURRENT ASSESSMENT – CHEI'S DISTRIBUTION SYSTEM

CHEI relies on approximately 27 km of circuits and 288 transformers to re-deliver approximately 29,500,000kWh of energy and 14,000 kW of power to approximately 2,000 customers. CHEI's circuits include approximately 15km of overhead lines and 12km of buried conductor. CHEI is entirely embedded within Hydro One Networks Inc.'s low voltage system.

CHEI distributes power to its customers through its municipal distribution substations which is comprised of primarily urban customers. CHEI owns one municipal substation within its service territory.

CHEI has completed the installation of approximately 1960 Smart Meters for residential and small commercial (GS<50kW) customers. CHEI intends to explore the potential use of the communication capability of the Smart Meter system to further improve customer service through more advanced outage detection and outage response.

Since the introduction of the Feed-in-Tariff (FIT) program, CHEI has connected a total of:

- 6 MicroFIT contracts issued

The distribution system has been virtually unaffected by the projects connected thus far. The number of connections in 2010 (1), 2011 (2), 2012(2), 2013 (1) has continued on a slow but steady pace and it is likely that the rate of connections will decrease slightly due to the decrease in the contract pricing offered by the Ontario Power Authority.

Overall, CHEI's distribution system has been determined to be adequate to accept the influx of renewable generation that is anticipated. CHEI continues to work with its host distributor to address the as they arise. There are no known barriers within CHEI's distribution system for projects that are serviced by its own municipal substations.

Based on the fact that there are no known barriers to renewable generation related to matters under the control of CHEI, the utility does not propose any material investments in renewable infrastructure. The utility does expect modest growth in renewable generation and minor system expansions/upgrades to accommodate renewable generation but does not seek to fund those expansions through this GEA Plan.

2.1 System Limitations

For MicroFIT generation, the number of connections to a CHEI owned feeder will be limited, based on the minimum feeder loading (limiting the number of MicroFIT generators connected to a feeder is necessary to prevent islanding condition). To determine feeder limits, CHEI will continue to monitor feeder loading data to determine minimum feeder loads.

With the ongoing upgrades on the substation, it is anticipated that the connection of small-scale renewable generation will not impose limitations, but that over time a larger concentration of renewable generators on the same distribution feeder could have a noticeable impact on the distribution system and upstream elements. CHEI does not anticipate a sufficient number of small-scale projects to reach a level of constraint in the near term of this GEA Plan.

Tables below, show connection limitations as well as the “Peak Annual Loading” on the substation.

Peak Annual Loading

Feeder	Phase	Rating	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
44kV Switch		3173	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
44kV Fuses		1015	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
44kV Trans. ONAN		520	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
44kV Trans. ONAF		693	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
8.32kV Switchgear		1200	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
8.32kV Feeder Switches		600	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
8.32kV Fuses (Continuous)		300	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
8.32kV Fuses (Daily 8 hour)		306	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
8.32kV Fuses (Daily 8 hour)		320	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
Feeder 1	R	461	204.6	206.6	208.7	210.8	212.9	215.0	217.2	219.4	221.6	223.8	226.0
	W	461	214.6	216.8	218.9	221.1	223.3	225.6	227.8	230.1	232.4	234.7	237.1
	B	461	198.0	200.0	202.0	204.0	206.1	208.1	210.2	212.3	214.4	216.6	218.7
Feeder 2	R	461	171.7	173.5	193.8	195.8	197.7	199.7	201.7	203.7	205.8	207.8	209.9
	W	461	175.7	177.5	190.5	192.4	194.3	196.2	198.2	200.2	202.2	204.2	206.2
	B	461	178.6	180.4	189.5	191.4	193.3	195.2	197.2	199.2	201.2	203.2	205.2
Feeder 3	R	461	193.2	195.1	197.1	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
	W	461	155.2	156.7	178.5	230.4	257.9	272.6	275.3	278.1	280.9	283.7	286.5
	B	461	186.9	188.8	190.6	242.7	270.3	285.1	288.0	290.8	293.7	296.7	299.7

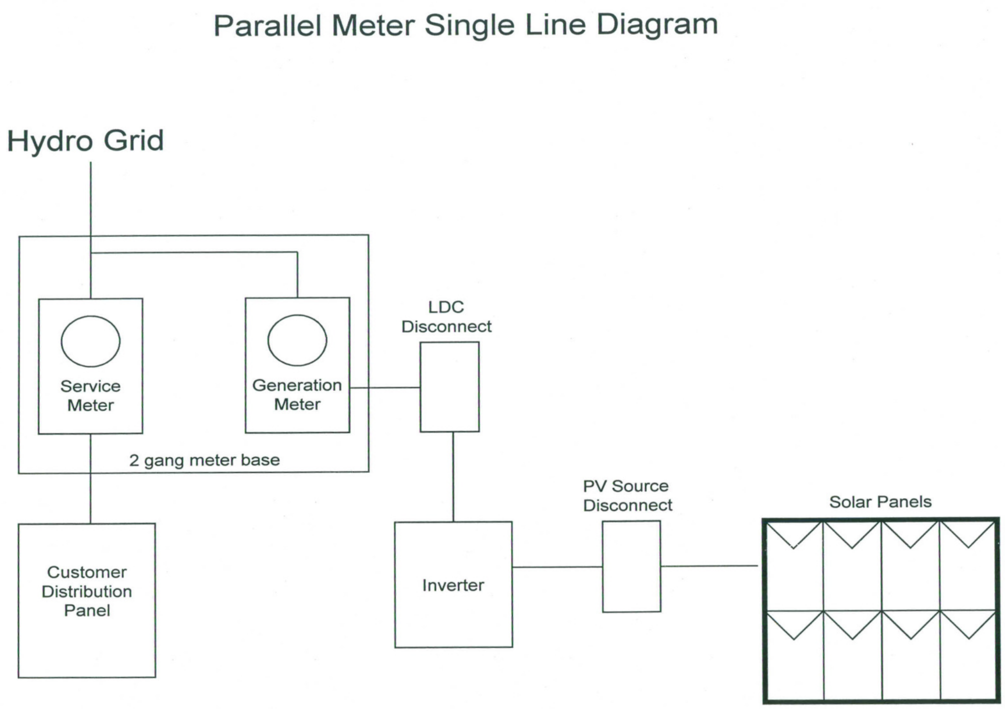
3.0 ANTICIPATED RENEWABLE GENERATION CONNECTION REQUESTS

Given the interest expressed by CHEI customers to-date, the forecasted the expected number of Micro-FIT applications is presented in Table 3 below. These numbers provided are speculative in nature, but they are based on experience dealing with customers over the past several years.

Table 2 – Forecast of connections

Application Type	2013	2014	2015	2016	2017
Forecast microFIT Connections	6	3	3	3	3

CHEI expects these connections to be accommodated with standard metering and connection techniques. (example is provided in the schematic below)



With respect to large scale projects, CHEI does not anticipate significant uptake for large scale projects. In the event these projects do materialize, the utility generally has sufficient lead time to allow for an appropriate response by CHEI and Hydro One.

In conclusion, based on the anticipated uptake of the program and an assessment of the systems capacities, CHEI is forecasting sufficient capacity to accommodate the anticipated connections with the need to prioritize the projects.

3.1 Consultation with Affected Transmitter

Being an embedded utility, CHEI must consult with Hydro One on each connection request. This gives Hydro One an opportunity to assess and address capacity issues within its service territory. CHEI will continue to work co-operatively with Hydro One as new connections are added to the system.

3.2 Planned Development to accommodate Renewable Generation

As noted throughout this GEA Plan, CHEI has not proposed any development or expansions of its distribution system in order to accommodate Renewable Generation.

3.3 Prioritization Method

Projects will be prioritized to align with the intent of the OPA FIT and microFIT programs. Prioritization of FIT projects is based on project application dates and the ongoing status of the new development. CHEI intends to prioritize and expedite renewable generation projects that are ready to connect to the distribution system.

3.4 Direct Benefits for Customers

CHEI is not proposing that any of its costs incurred to make eligible investments for the purpose of enabling the connection of renewable electricity generation be recovered from provincial ratepayers rather than solely from CHEI's ratepayers. It is therefore not necessary to calculate the direct benefits accruing to CHEI customers.

3.5 Proposed Budget

There is no proposed budget with respect to connection of renewable generation under the FIT program. CHEI will undertake an annual review of the anticipated renewable generation connection project schedule as well as related costs.

4. REPORTING

4.1 Green Energy Act Plan Annual Status Report

CHEI will review this document on a regular basis and will publish updates to this document as needed or required by the OEB.

Once the OEB provides further direction as to the time and manner of GEA Plan reporting, indicated as pending in EB-2009-0397 (page 25), CHEI will comply with the OEB directives.

E2.T2.S9 HST

As a result of the implementation of HST in the province of Ontario on July 1, 2010, CHEI has considered the reduction in capital expenditures relating to the purchase of products and services due to the increased input tax credit (ITC). Neither the 2013 Bridge Year forecast nor the 2014 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2010.

As per instructed by the Board, starting in July 1, 2010, Embrun recorded in deferral account 1592, (PILs and Tax Variances, Sub-account HST / OVAT ITCs), the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and had become subject to HST. The Balance of 1592 is detailed at Exhibit 9.

Tab 3 – Service Quality and Reliability Performance

E2.T3.S1 ESQR's

CHEI reports its service quality indicators ("SQIs") annually to the Ontario Energy Board. The SQIs are defined in Chapter 7 of the Distribution System Code. CHEI has not only met but exceeded the minimum standards for all SQIs each year, as indicated in the following table:

Table 11 – 3 Year Historical SQI's

Unitized Statistics and Service Quality Requirements	2010	2011	2012
Service Quality Requirements			
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	100.00	100.00
High Voltage Connections (OEB Min. Standard: 90%)	N/A	100.00	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	93.50	93.30	96.00
Appointments Met (OEB Min. Standard: 90%)	100.00	100.00	100.00
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	100.00	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	100.00
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	6.50	7.20	4.00
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	100.00	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	N/A	N/A
Reconnection Performance Standard (OEB Min. Standard: 85%)		100.00	93.80
Service Reliability Indices			
SAIDI-Annual	0.02	10.00	3.08
SAIFI-Annual	0.01	4.01	1.02
CAIDI-Annual	2.31	2.49	3.02
Loss of Supply Adjusted Service Reliability Indices			
SAIDI-Annual	-	9.00	0.08
SAIFI-Annual	-	3.00	0.02
CAIDI-Annual	N/A	3.00	4.00

Appendix A – Decision and Order, EB-2012-0094

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0094

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

AND IN THE MATTER OF an application by Cooperative Hydro Embrun Inc. for an order or orders approving or fixing just and reasonable distribution rates related to Smart Meter deployment, to be effective May 1, 2012.

BEFORE: Ken Quesnelle
Presiding Member

Marika Hare
Member

FINAL RATE ORDER

August 23, 2012

Introduction

Cooperative Hydro Embrun Inc. ("CHEI"), a licensed distributor of electricity, filed an application (the "Application") with the Ontario Energy Board (the "Board") on March 16, 2012 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that CHEI charges for electricity distribution, to be effective May 1, 2012.

CHEI sought Board approval for the disposition and recovery of costs related to smart meter deployment, offset by Smart Meter Funding Adder ("SMFA") revenues collected from May 1, 2006 to April 30, 2012. CHEI requested approval of proposed Smart Meter Disposition Riders ("SMDRs") and Smart Meter Incremental Revenue Requirement Rate Riders ("SMIRRs") effective May 1, 2012.

In its Decision and Order on the Application issued on July 26, 2012, the Board ordered CHEI to file with the Board a draft Rate Order ("DRO") attaching a proposed Tariff of Rates and Charges reflecting the Board's findings, within 7 days of the date of the Decision and Order. The DRO was also to include customer rate impacts and detailed supporting information showing the calculation of the final rates.

On August 1, 2012, CHEI filed a DRO with revised models and a proposed Tariff of Rates and Charges.

On August 8, 2012 Board staff filed comments on the DRO. Board staff noted that CHEI had not accounted for interest on OM&A and depreciation expenses to August 31, 2012 due to the September 1, 2012 implementation date approved in the Decision and Order. In addition, Board staff noted that, in the Smart Meter Model, CHEI used sheet 8B for calculating interest on OM&A and depreciation expenses. Board staff submitted that the interest is more accurately calculated using sheet 8A and not sheet 8B. Board staff's submission included a revised Smart Meter Model which took into account these changes and also modified the class-specific SMDR to reflect the interest on SMFA revenues and on OM&A and depreciation expenses to August 31, 2012.

VECC did not submit any comments on the DRO.

On August 15, 2012, CHEI filed a reply submission on the DRO, stating that it concurred with Board staff's comments. The reply submission was supported with an updated proposed Tariff of Rates and Charges and bill impacts.

The Board has reviewed the information provided by CHEI and Board staff's comments on the proposed Tariff of Rates and Charges. Upon review, the Board has noted that CHEI's DRO did not comply with the Board's Decision and Order in that CHEI did not reflect four months of SMIRR revenues in an adjusted SMDR, to reflect the foregone revenues from May 1, 2012 to August 31, 2012. The Board has directed Board staff to make the necessary corrections, which are summarized in the following table:

	Smart Meter Disposition Rider (effective September 1, 2012 to April 30, 2013)	
	CHEI's Reply to DRO, August 15, 2012	*Corrected*
Residential	($0.96)/month	($0.23)/month
GS < 50 kW	$9.73/month	$11.83/month
GS > 50 kW	$48.78/month	$56.13/month

With these corrections, the Board is satisfied that the attached Tariff of Rates and Charges accurately reflects the Board's Decision and Order.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this Order will become final effective September 1, 2012 and will apply to electricity consumed or estimated to have been consumed on and after September 1, 2012. Cooperative Hydro Embrun Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, August 23, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Final Rate Order

Cooperative Hydro Embrun Inc.

Tariff of Rates and Charges

Board File No: EB-2012-0094

DATED: August 23, 2012

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0164
EB-2012-0094

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	13.63
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2013	$	(0.23)
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	1.44
Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0021)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0014
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0164
EB-2012-0094

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	20.24
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2013	$	11.83
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	4.20
Distribution Volumetric Rate	$/kWh	0.0167
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0021)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0014
Retail Transmission Rate – Network Service Rate	$/kWh	0.0056
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0164
EB-2012-0094

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	244.10
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2013	$	56.13
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	14.30
Distribution Volumetric Rate	$/kW	4.5228
Low Voltage Service Rate	$/kW	0.4778
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2014	$/kW	0.0284
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.7109)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.4834
Retail Transmission Rate – Network Service Rate	$/kW	2.2389
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7009

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
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EB-2011-0164
EB-2012-0094

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	39.82
Distribution Volumetric Rate	$/kWh	0.0104
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0021)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0014
Retail Transmission Rate – Network Service Rate	$/kWh	0.0056
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

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EB-2011-0164
EB-2012-0094

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.59
Distribution Volumetric Rate	$/kW	6.4834
Low Voltage Service Rate	$/kW	0.3694
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.7349)
Retail Transmission Rate – Network Service Rate	$/kW	1.6886
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3149

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

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EB-2011-0164
EB-2012-0094

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
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Implementation Date September 1, 2012

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EB-2011-0164
EB-2012-0094

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	25.00
Returned cheques charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Special meter reads	$	20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	20.00
Collection of account charge – no disconnection – after regular hours	$	50.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	25.00
Disconnect/Reconnect Charge - At Meter after Regular Hours	$	50.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	25.00
Install/Remove load control device – after regular hours	$	50.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service installation and removal – overhead – no transformer	$	500.00
Temporary service installation and removal – underground – no transformer	$	300.00

Updated August 23, 2012 for Smart Meter Decision EB-2012-0094

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012
Implementation Date September 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0164
EB-2012-0094

Temporary service installation and removal – overhead – with transformer	$	1,000.00
Specific charge for access to power poles $/pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0579
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0473
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Updated August 23, 2012 for Smart Meter Decision EB-2012-0094

Appendix B – Smart Meter Model

V 2.17

Ontario Energy Board

Smart Meter Model

Choose Your Utility:

COLLUS Power Corporation
Cooperative Hydro Embrun Inc.

Application Contact Information

Name:	BENOIT LAMARCHE
Title:	MANAGER
Phone Number:	613-443-5110
Email Address:	embrunhydro@magma .ca
We are applying for rates effective:	May 1, 2012
Last COS Re-based Year	2011

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Smart Meter Model

Cooperative Hydro Embrun Inc.

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data

	2006	2007	2008	2009	2010	2011	2012 and later	Total
	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan								
Actual/Planned number of Smart Meters installed during the Calendar Year								
Residential	0	0	0	1,755	22	9	10	1796
General Service < 50 kW	0	0	0	152	3	3	4	162
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)	0	0	0	1907	25	12	14	1958
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	0.00%	0.00%	0.00%	97.40%	98.67%	99.28%	100.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed	0	0	0	0	12	0	0	12
Other (please identify)	0	0	0	0	0	0	0	0
Total Number of Smart Meters installed or planned to be installed	0	0	0	1907	37	12	14	1970

1 Capital Costs

	Asset Type								
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter	0	0	0	217,493	14,803	1,754	2,141	$ 236,191
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				33,904	2,640			$ 36,544
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*									$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ -	$ 251,397	$ 17,443	$ 1,754	$ 2,141	$ 272,735

	Asset Type								
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Smart Meter				6,889	0	1,883		$ 8,772
1.2.2 Repeaters *(may include radio licence, etc.)*									$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Tools & Equipment				2,542	1,663			$ 4,205
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 9,430	$ 1,663	$ 1,883	$ -	$ 12,977

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware									$ -
1.3.2 Computer Software									$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*									$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS									$ -
1.5.3 Professional Fees									$ -
1.5.4 Integration	Smart Meter				28,705				$ 28,705
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital									$ -
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ -	$ -	$ 28,705	$ -	$ -	$ -	$ 28,705
Total Capital Costs Related to Minimum Functionality		$ -	$ -	$ -	$ 289,532	$ 19,106	$ 3,638	$ 2,141	$ 314,417

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06	Computer Software								$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service	Applications Software								$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.									$ -
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter Capital Costs		$ -	$ -	$ -	$ 289,532	$ 19,106	$ 3,638	$ 2,141	$ 314,417

2 OM&A Expenses

	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)								
2.1.1 Maintenance *(may include meter reverification costs, etc.)*								$ -
2.1.2 Other *(please specifiy)*								$ -
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)								
2.2.1 Maintenance								$ -
2.2.2 Other *(please specifiy)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)								
2.3.1 Hardware Maintenance *(may include server support, etc.)*								$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*								$ -
2.3.2 Other *(please specifiy)*								$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)								
2.4.1 WAN Maintenance								$ -
2.4.2 Other *(please specifiy)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY								
2.5.1 Business Process Redesign								$ -
2.5.2 Customer Communication (may include project communication, etc.)								$ -
2.5.3 Program Management								$ -
2.5.4 Change Management (may include training, etc.)								$ -
2.5.5 Administration Costs								$ -
2.5.6 Other AMI Expenses *(please specify)*								$ -
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06								$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service								$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.								$ -
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ -	$ -	$ 286,991	$ 17,443	$ 3,638	$ 2,141	$ 310,212
3.1.2	Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.3	Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ 2,542	$ 1,663	$ -	$ -	$ 4,205
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ -**	**$ -**	**$ -**	**$ 289,532**	**$ 19,106**	**$ 3,638**	**$ 2,141**	**$ 314,417**
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Ontario Energy Board

Smart Meter Model

Cooperative Hydro Embrun Inc.

	2006	2007	2008	2009	2010	2011	2012 and later
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization			0.0%	0.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	53.3%	56.7%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%
Preferred Shares							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate			0.00%	0.00%	2.07%	2.07%	2.07%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.25%	6.25%	6.25%	6.25%	5.87%	5.87%	5.87%
Target Return on Equity (ROE)	9.0%	9.00%	9.00%	9.00%	9.85%	9.85%	9.85%
Return on Preferred Shares							
WACC	7.63%	7.63%	7.53%	7.44%	7.31%	7.31%	7.31%
Working Capital Allowance							
Working Capital Allowance Rate *(% of the sum of Cost of Power + controllable expenses)*	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Taxes/PILs							
Aggregate Corporate Income Tax Rate	18.62%	18.62%	16.50%	16.50%	16.00%	15.50%	15.50%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%

Depreciation Rates

(expressed as expected useful life in years)

Smart Meters - years	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	2	2	2	2	2	2	2
- rate (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Computer Software - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

CCA Rates

Smart Meters - CCA Class	1	47	47	47	47	47	47
Smart Meters - CCA Rate	4%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	45	50	50	52	52	50	50
Computer Equipment - CCA Rate	45%	55%	55%	100%	100%	55%	55%
General Equipment - CCA Class	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class	12	12	12	12	12	12	12
Applications Software - CCA Rate	100%	100%	100%	100%	100%	100%	100%

Assumptions

[1] *Planned smart meter installations occur evenly throughout the year.*

[2] *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Ontario Energy Board
Smart Meter Model

Cooperative Hydro Embrun Inc.

	2006	2007	2008	2009	2010	2011	2012 and later
Net Fixed Assets - Smart Meters							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 286,991	$ 304,434	$ 308,071
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 286,991	$ 17,443	$ 3,638	$ 2,141
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 286,991	$ 304,434	$ 308,071	$ 310,212
Accumulated Depreciation							
Opening Balance		$ -	$ -	$ -	-$ 9,566	-$ 29,280	-$ 49,697
Amortization expense during year	$ -	$ -	$ -	-$ 9,566	-$ 19,714	-$ 20,417	-$ 20,609
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 9,566	-$ 29,280	-$ 49,697	-$ 70,307
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 277,424	$ 275,153	$ 258,374
Closing Balance	$ -	$ -	$ -	$ 277,424	$ 275,153	$ 258,374	$ 239,905
Average Net Book Value	$ -	$ -	$ -	$ 138,712	$ 276,289	$ 266,764	$ 249,140

	2006	2007	2008	2009	2010	2011	2012 and later
Net Fixed Assets - Computer Hardware							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	2006	2007	2008	2009	2010	2011	2012 and later
Net Fixed Assets - Computer Software (including Applications Software)							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Tools and Equipment

Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 2,542	$ 4,205	$ 4,205
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 2,542	$ 1,663	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 2,542	$ 4,205	$ 4,205	$ 4,205
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	-$ 127	-$ 464	-$ 885
Amortization expense during year	$ -	$ -	$ -	-$ 127	-$ 337	-$ 420	-$ 420
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 127	-$ 464	-$ 885	-$ 1,305
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 2,415	$ 3,740	$ 3,320
Closing Balance	$ -	$ -	$ -	$ 2,415	$ 3,740	$ 3,320	$ 2,899
Average Net Book Value	$ -	$ -	$ -	$ 1,207	$ 3,077	$ 3,530	$ 3,110

Net Fixed Assets - Other Equipment

Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model

Cooperative Hydro Embrun Inc.

	2006	2007	2008	2009	2010	2011	2012 and Later
Average Net Fixed Asset Values (from Sheet 4)							
Smart Meters	$ -	$ -	$ -	$ 138,712	$ 276,289	$ 266,764	$ 249,140
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ -	$ -	$ -	$ 1,207	$ 3,077	$ 3,530	$ 3,110
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ -**	**$ -**	**$ -**	**$ 139,919**	**$ 279,366**	**$ 270,294**	**$ 252,249**
Working Capital							
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%
Working Capital Allowance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental Smart Meter Rate Base	**$ -**	**$ -**	**$ -**	**$ 139,919**	**$ 279,366**	**$ 270,294**	**$ 252,249**
Return on Rate Base							
Capital Structure							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 11,175	$ 10,812	$ 10,090
Deemed Long Term Debt	$ -	$ -	$ -	$ 79,334	$ 156,445	$ 151,364	$ 141,260
Equity	$ -	$ -	$ -	$ 60,585	$ 111,746	$ 108,117	$ 100,900
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ -	$ -	$ 139,919	$ 279,366	$ 270,294	$ 252,249
Return on							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 231	$ 224	$ 209
Deemed Long Term Debt	$ -	$ -	$ -	$ 4,958	$ 9,183	$ 8,885	$ 8,292
Equity	$ -	$ -	$ -	$ 5,453	$ 11,007	$ 10,650	$ 9,939
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ -	$ -	$ 10,411	$ 20,422	$ 19,758	$ 18,439
Operating Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization Expenses (from Sheet 4)							
Smart Meters	$ -	$ -	$ -	$ 9,566	$ 19,714	$ 20,417	$ 20,609
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ -	$ -	$ -	$ 127	$ 337	$ 420	$ 420
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ -	$ -	$ -	$ 9,693	$ 20,051	$ 20,837	$ 21,030
Incremental Revenue Requirement before Taxes/PILs	$ -	$ -	$ -	$ 20,104	$ 40,473	$ 40,596	$ 39,469
Calculation of Taxable Income							
Incremental Operating Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization Expense	$ -	$ -	$ -	$ 9,693	$ 20,051	$ 20,837	$ 21,030
Interest Expense	$ -	$ -	$ -	$ 4,958	$ 9,415	$ 9,109	$ 8,501
Net Income for Taxes/PILs	$ -	$ -	$ -	$ 5,453	$ 11,007	$ 10,650	$ 9,939
Grossed-up Taxes/PILs (from Sheet 7)	$ -	$ -	$ -	$ 1,303.93	$ 1,675.09	$ 1,661.67	$ 1,867.96
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ -	$ -	$ 21,408	$ 42,148	$ 42,257	$ 41,337

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 275,510.95	$ 270,215.55	$ 252,090.39
Capital Additions	$ -	$ -	$ -	$ 286,990.57	$ 17,443.21	$ 3,637.59	$ 2,140.79
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 286,990.57	$ 292,954.15	$ 273,853.14	$ 254,231.19
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 143,495.28	$ 8,721.60	$ 1,818.80	$ 1,070.40
Reduced UCC	$ -	$ -	$ -	$ 143,495.28	$ 284,232.55	$ 272,034.35	$ 253,160.79
CCA Rate Class	1	47	47	47	47	47	47
CCA Rate	4%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ -	$ -	$ 11,479.62	$ 22,738.60	$ 21,762.75	$ 20,252.86
Closing UCC	$ -	$ -	$ -	$ 275,510.95	$ 270,215.55	$ 252,090.39	$ 233,978.32

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	45	50	50	52	52	50	50
CCA Rate	45%	55%	55%	100%	100%	55%	55%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 2,287.48	$ 3,326.75	$ 2,661.40
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ 2,541.64	$ 1,663.08	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 2,541.64	$ 3,950.56	$ 3,326.75	$ 2,661.40
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 1,270.82	$ 831.54	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ 1,270.82	$ 3,119.02	$ 3,326.75	$ 2,661.40
CCA Rate Class	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ 254.16	$ 623.80	$ 665.35	$ 532.28
Closing UCC	$ -	$ -	$ -	$ 2,287.48	$ 3,326.75	$ 2,661.40	$ 2,129.12

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
INCOME TAX							
Net Income	$ -	$ -	$ -	$ 5,452.66	$ 11,007.03	$ 10,649.57	$ 9,938.62
Amortization	$ -	$ -	$ -	$ 9,693.43	$ 20,051.46	$ 20,837.31	$ 21,029.92
CCA - Smart Meters	$ -	$ -	$ -	-$ 11,479.62	-$ 22,738.60	-$ 21,762.75	-$ 20,252.86
CCA - Computers	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	-$ 254.16	-$ 623.80	-$ 665.35	-$ 532.28
Change in taxable income	$ -	$ -	$ -	$ 3,412.31	$ 7,696.08	$ 9,058.79	$ 10,183.40
Tax Rate (from Sheet 3)	18.62%	18.62%	16.50%	16.50%	16.00%	15.50%	15.50%
Income Taxes Payable	$ -	$ -	$ -	$ 563.03	$ 1,231.37	$ 1,404.11	$ 1,578.43
ONTARIO CAPITAL TAX							
Smart Meters	$ -	$ -	$ -	$ 277,424.22	$ 275,153.28	$ 258,374.03	$ 239,905.37
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software (Including Application Software)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ -	$ -	$ -	$ 2,414.56	$ 3,740.32	$ 3,319.85	$ 2,899.38
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ -	$ -	$ -	$ 279,838.78	$ 278,893.60	$ 261,693.88	$ 242,804.75
Less: Exemption							
Deemed Taxable Capital	$ -	$ -	$ -	$ 279,838.78	$ 278,893.60	$ 261,693.88	$ 242,804.75
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -	$ 629.64	$ 209.17	$ -	$ -
Change in Income Taxes Payable	$ -	$ -	$ -	$ 563.03	$ 1,231.37	$ 1,404.11	$ 1,578.43
Change in OCT	$ -	$ -	$ -	$ 629.64	$ 209.17	$ -	$ -
PILs	$ -	$ -	$ -	$ 1,192.67	$ 1,440.54	$ 1,404.11	$ 1,578.43

Gross Up PILs

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Tax Rate	18.62%	18.62%	16.50%	16.50%	16.00%	15.50%	15.50%
Change in Income Taxes Payable	$ -	$ -	$ -	$ 674.29	$ 1,465.92	$ 1,661.67	$ 1,867.96
Change in OCT	$ -	$ -	$ -	$ 629.64	$ 209.17	$ -	$ -
PILs	**$ -**	**$ -**	**$ -**	**$ 1,303.93**	**$ 1,675.09**	**$ 1,661.67**	**$ 1,867.96**

Ontario Energy Board

Smart Meter Model

Cooperative Hydro Embrun Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4		4.29%

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
May-06	2006	Q2	$ -		4.14%	$ -	$ -		
Jun-06	2006	Q2	$ -		4.14%	$ -	$ -		$ 0.27
Jul-06	2006	Q3	$ -	$ 226.56	4.59%	$ -	$ 226.56		$ 0.27
Aug-06	2006	Q3	$ 226.56	$ 500.76	4.59%	$ 0.87	$ 728.19		$ 0.27
Sep-06	2006	Q3	$ 727.32	$ 455.97	4.59%	$ 2.78	$ 1,186.07		$ 0.27
Oct-06	2006	Q4	$ 1,183.29	$ 505.02	4.59%	$ 4.53	$ 1,692.84		$ 0.27
Nov-06	2006	Q4	$ 1,688.31	$ 468.36	4.59%	$ 6.46	$ 2,163.13		$ 0.27
Dec-06	2006	Q4	$ 2,156.67	$ 502.52	4.59%	$ 8.25	$ 2,667.44	$ 2,682.08	$ 0.27
Jan-07	2007	Q1	$ 2,659.19	$ 722.24	4.59%	$ 10.17	$ 3,391.60		$ 0.27
Feb-07	2007	Q1	$ 3,381.43	$ 283.21	4.59%	$ 12.93	$ 3,677.57		$ 0.27
Mar-07	2007	Q1	$ 3,664.64	$ 466.05	4.59%	$ 14.02	$ 4,144.71		$ 0.27
Apr-07	2007	Q2	$ 4,130.69	$ 506.86	4.59%	$ 15.80	$ 4,653.35		$ 0.27
May-07	2007	Q2	$ 4,637.55	$ 475.79	4.59%	$ 17.74	$ 5,131.08		$ 0.27
Jun-07	2007	Q2	$ 5,113.34	$ 525.13	4.59%	$ 19.56	$ 5,658.03		$ 0.27
Jul-07	2007	Q3	$ 5,638.47	$ 476.77	4.59%	$ 21.57	$ 6,136.81		$ 0.27
Aug-07	2007	Q3	$ 6,115.24	$ 504.31	4.59%	$ 23.39	$ 6,642.94		$ 0.27
Sep-07	2007	Q3	$ 6,619.55	$ 474.37	4.59%	$ 25.32	$ 7,119.24		$ 0.27
Oct-07	2007	Q4	$ 7,093.92	$ 513.57	5.14%	$ 30.39	$ 7,637.88		$ 0.27
Nov-07	2007	Q4	$ 7,607.49	$ 475.14	5.14%	$ 32.59	$ 8,115.22		$ 0.27
Dec-07	2007	Q4	$ 8,082.63	$ 529.00	5.14%	$ 34.62	$ 8,646.25	$ 6,210.54	$ 0.27
Jan-08	2008	Q1	$ 8,611.63	$ 763.61	5.14%	$ 36.89	$ 9,412.13		$ 0.27
Feb-08	2008	Q1	$ 9,375.24	$ 246.52	5.14%	$ 40.16	$ 9,661.92		$ 0.27
Mar-08	2008	Q1	$ 9,621.76	$ 483.84	5.14%	$ 41.21	$ 10,146.81		$ 0.27
Apr-08	2008	Q2	$ 10,105.60	$ 525.62	4.08%	$ 34.36	$ 10,665.58		$ 0.27
May-08	2008	Q2	$ 10,631.22	$ 482.13	4.08%	$ 36.15	$ 11,149.50		$ 0.27
Jun-08	2008	Q2	$ 11,113.35	$ 538.27	4.08%	$ 37.79	$ 11,689.41		$ 0.27
Jul-08	2008	Q3	$ 11,651.62	$ 524.41	3.35%	$ 32.53	$ 12,208.56		$ 0.27
Aug-08	2008	Q3	$ 12,176.03	$ 522.48	3.35%	$ 33.99	$ 12,732.50		$ 0.27
Sep-08	2008	Q3	$ 12,698.51	$ 487.06	3.35%	$ 35.45	$ 13,221.02		$ 0.27
Oct-08	2008	Q4	$ 13,185.57	$ 528.83	3.35%	$ 36.81	$ 13,751.21		$ 0.27
Nov-08	2008	Q4	$ 13,714.40	$ 493.75	3.35%	$ 38.29	$ 14,246.44		$ 0.27
Dec-08	2008	Q4	$ 14,208.15	$ 537.59	3.35%	$ 39.66	$ 14,785.40	$ 6,577.40	$ 0.27
Jan-09	2009	Q1	$ 14,745.74	$ 496.65	2.45%	$ 30.11	$ 15,272.50		$ 0.27
Feb-09	2009	Q1	$ 15,242.39	$ 542.53	2.45%	$ 31.12	$ 15,816.04		$ 0.27
Mar-09	2009	Q1	$ 15,784.92	$ 499.50	2.45%	$ 32.23	$ 16,316.65		$ 0.27
Apr-09	2009	Q2	$ 16,284.42	$ 547.71	1.00%	$ 13.57	$ 16,845.70		$ 0.27
May-09	2009	Q2	$ 16,832.13	$ 501.35	1.00%	$ 14.03	$ 17,347.51		$ 1.00
Jun-09	2009	Q2	$ 17,333.48	$ 1,323.28	1.00%	$ 14.44	$ 18,671.20		$ 1.00
Jul-09	2009	Q3	$ 18,656.76	$ 1,820.15	0.55%	$ 8.55	$ 20,485.46		$ 1.00
Aug-09	2009	Q3	$ 20,476.91	$ 2,010.23	0.55%	$ 9.39	$ 22,496.53		$ 1.00
Sep-09	2009	Q3	$ 22,487.14	$ 1,831.63	0.55%	$ 10.31	$ 24,329.08		$ 1.00
Oct-09	2009	Q4	$ 24,318.77	$ 2,013.82	0.55%	$ 11.15	$ 26,343.74		$ 1.00
Nov-09	2009	Q4	$ 26,332.59	$ 1,842.93	0.55%	$ 12.07	$ 28,187.59		$ 1.00
Dec-09	2009	Q4	$ 28,175.52	$ 2,023.66	0.55%	$ 12.91	$ 30,212.09	$ 15,653.32	$ 1.00
Jan-10	2010	Q1	$ 30,199.18	$ 1,841.46	0.55%	$ 13.84	$ 32,054.48		$ 1.00
Feb-10	2010	Q1	$ 32,040.64	$ 2,006.59	0.55%	$ 14.69	$ 34,061.92		$ 1.00
Mar-10	2010	Q1	$ 34,047.23	$ 1,868.70	0.55%	$ 15.60	$ 35,931.53		$ 1.00
Apr-10	2010	Q2	$ 35,915.93	$ 2,010.46	0.55%	$ 16.46	$ 37,942.85		$ 1.00
May-10	2010	Q2	$ 37,926.39	$ 1,857.51	0.55%	$ 17.38	$ 39,801.28		$ 1.33
Jun-10	2010	Q2	$ 39,783.90	$ 2,380.42	0.55%	$ 18.23	$ 42,182.55		$ 1.33
Jul-10	2010	Q3	$ 42,164.32	$ 2,445.67	0.89%	$ 31.27	$ 44,641.26		$ 1.33
Aug-10	2010	Q3	$ 44,609.99	$ 2,712.40	0.89%	$ 33.09	$ 47,355.48		$ 1.33
Sep-10	2010	Q3	$ 47,322.39	$ 2,473.82	0.89%	$ 35.10	$ 49,831.31		$ 1.33
Oct-10	2010	Q4	$ 49,796.21	$ 2,673.85	1.20%	$ 49.80	$ 52,519.86		$ 1.33
Nov-10	2010	Q4	$ 52,470.06	$ 2,483.62	1.20%	$ 52.47	$ 55,006.15		$ 1.33
Dec-10	2010	Q4	$ 54,953.68	$ 2,673.25	1.20%	$ 54.95	$ 57,681.88	$ 27,780.63	$ 1.33
Jan-11	2011	Q1	$ 57,626.93	$ 3,701.26	1.47%	$ 70.59	$ 61,398.78		$ 1.33
Feb-11	2011	Q1	$ 61,328.19	$ 2,581.79	1.47%	$ 75.13	$ 63,985.11		$ 1.33
Mar-11	2011	Q1	$ 63,909.98	$ 2,587.95	1.47%	$ 78.29	$ 66,576.22		$ 1.33
Apr-11	2011	Q2	$ 66,497.93	$ 2,587.47	1.47%	$ 81.46	$ 69,166.86		$ 1.33
May-11	2011	Q2	$ 69,085.40	$ 2,580.69	1.47%	$ 84.63	$ 71,750.72		$ 1.33
Jun-11	2011	Q2	$ 71,666.09	$ 2,592.32	1.47%	$ 87.79	$ 74,346.20		$ 1.33
Jul-11	2011	Q3	$ 74,258.41	$ 2,590.42	1.47%	$ 90.97	$ 76,939.80		$ 1.33
Aug-11	2011	Q3	$ 76,848.83	$ 2,585.95	1.47%	$ 94.14	$ 79,528.92		$ 1.33
Sep-11	2011	Q3	$ 79,434.78	$ 2,613.45	1.47%	$ 97.31	$ 82,145.54		$ 1.33
Oct-11	2011	Q4	$ 82,048.23	$ 2,594.05	1.47%	$ 100.51	$ 84,742.79		$ 1.33
Nov-11	2011	Q4	$ 84,642.28	$ 2,594.15	1.47%	$ 103.69	$ 87,340.12		$ 1.33
Dec-11	2011	Q4	$ 87,236.43	$ 2,580.72	1.47%	$ 106.86	$ 89,924.01	$ 33,261.59	$ 1.33
Jan-12	2012	Q1	$ 89,817.15	$ 2,600.00	1.47%	$ 110.03	$ 92,527.18		$ 1.33
Feb-12	2012	Q1	$ 92,417.15	$ 2,600.00	1.47%	$ 113.21	$ 95,130.36		$ 1.33

Ontario Energy Board

Smart Meter Model

Cooperative Hydro Embrun Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Mar-12	2012	Q1	$ 95,017.15	$ 2,600.00	1.47%	$ 116.40	$ 97,733.55		$ 1.33
			Apr-12	2012	Q2	$ 97,617.15	$ 2,600.00	1.47%	$ 119.58	$ 100,336.73		$ 1.33
			May-12	2012	Q2	$ 100,217.15		1.47%	$ 122.77	$ 100,339.92		$ 1.33
			Jun-12	2012	Q2	$ 100,217.15		1.47%	$ 122.77	$ 100,339.92		$ 1.33
			Jul-12	2012	Q3	$ 100,217.15		1.47%	$ 122.77	$ 100,339.92		$ 1.33
			Aug-12	2012	Q3	$ 100,217.15		1.47%	$ 122.77	$ 100,339.92		$ 1.33
			Sep-12	2012	Q3	$ 100,217.15		0.00%	$ -	$ 100,217.15		$ 1.33
			Oct-12	2012	Q4	$ 100,217.15		0.00%	$ -	$ 100,217.15		$ 1.33
			Nov-12	2012	Q4	$ 100,217.15		0.00%	$ -	$ 100,217.15		$ 1.33
			Dec-12	2012	Q4	$ 100,217.15		0.00%	$ -	$ 100,217.15	$ 11,350.30	$ 1.33
			Total Funding Adder Revenues Collected				**$ 100,217.15**		**$ 3,298.71**	**$ 103,515.86**	**$ 103,515.86**	

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	0.00%	4.29%

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	2006	Q1	$ -			-	0.00%	-	-
Feb-06	2006	Q1	-			-	0.00%	-	-
Mar-06	2006	Q1	-			-	0.00%	-	-
Apr-06	2006	Q2	-			-	4.14%	-	-
May-06	2006	Q2	-			-	4.14%	-	-
Jun-06	2006	Q2	-			-	4.14%	-	-
Jul-06	2006	Q3	-			-	4.59%	-	-
Aug-06	2006	Q3	-			-	4.59%	-	-
Sep-06	2006	Q3	-			-	4.59%	-	-
Oct-06	2006	Q4	-			-	4.59%	-	-
Nov-06	2006	Q4	-			-	4.59%	-	-
Dec-06	2006	Q4	-			-	4.59%	-	-
Jan-07	2007	Q1	-			-	4.59%	-	-
Feb-07	2007	Q1	-			-	4.59%	-	-
Mar-07	2007	Q1	-			-	4.59%	-	-
Apr-07	2007	Q2	-			-	4.59%	-	-
May-07	2007	Q2	-			-	4.59%	-	-
Jun-07	2007	Q2	-			-	4.59%	-	-
Jul-07	2007	Q3	-			-	4.59%	-	-
Aug-07	2007	Q3	-			-	4.59%	-	-
Sep-07	2007	Q3	-			-	4.59%	-	-
Oct-07	2007	Q4	-			-	5.14%	-	-
Nov-07	2007	Q4	-			-	5.14%	-	-
Dec-07	2007	Q4	-			-	5.14%	-	-
Jan-08	2008	Q1	-			-	5.14%	-	-
Feb-08	2008	Q1	-			-	5.14%	-	-
Mar-08	2008	Q1	-			-	5.14%	-	-
Apr-08	2008	Q2	-			-	4.08%	-	-
May-08	2008	Q2	-			-	4.08%	-	-
Jun-08	2008	Q2	-			-	4.08%	-	-
Jul-08	2008	Q3	-			-	3.35%	-	-
Aug-08	2008	Q3	-			-	3.35%	-	-
Sep-08	2008	Q3	-			-	3.35%	-	-
Oct-08	2008	Q4	-			-	3.35%	-	-
Nov-08	2008	Q4	-			-	3.35%	-	-
Dec-08	2008	Q4	-			-	3.35%	-	-
Jan-09	2009	Q1	-		$ 807.79	807.79	2.45%	-	-
Feb-09	2009	Q1	807.79		$ 807.79	1,615.57	2.45%	1.65	1.65
Mar-09	2009	Q1	1,615.57		$ 807.79	2,423.36	2.45%	3.30	4.95
Apr-09	2009	Q2	2,423.36		$ 807.79	3,231.14	1.00%	2.02	6.97
May-09	2009	Q2	3,231.14		$ 807.79	4,038.93	1.00%	2.69	9.66
Jun-09	2009	Q2	4,038.93		$ 807.79	4,846.72	1.00%	3.37	13.03
Jul-09	2009	Q3	4,846.72		$ 807.79	5,654.50	0.55%	2.22	15.25
Aug-09	2009	Q3	5,654.50		$ 807.79	6,462.29	0.55%	2.59	17.84
Sep-09	2009	Q3	6,462.29		$ 807.79	7,270.08	0.55%	2.96	20.80
Oct-09	2009	Q4	7,270.08		$ 807.79	8,077.86	0.55%	3.33	24.13
Nov-09	2009	Q4	8,077.86		$ 807.79	8,885.65	0.55%	3.70	27.83
Dec-09	2009	Q4	8,885.65		$ 807.79	9,693.43	0.55%	4.07	31.91
Jan-10	2010	Q1	9,693.43		$ 1,670.96	11,364.39	0.55%	4.44	36.35
Feb-10	2010	Q1	11,364.39		$ 1,670.96	13,035.34	0.55%	5.21	41.56
Mar-10	2010	Q1	13,035.34		$ 1,670.96	14,706.30	0.55%	5.97	47.53
Apr-10	2010	Q2	14,706.30		$ 1,670.96	16,377.26	0.55%	6.74	54.27
May-10	2010	Q2	16,377.26		$ 1,670.96	18,048.21	0.55%	7.51	61.78
Jun-10	2010	Q2	18,048.21		$ 1,670.96	19,719.17	0.55%	8.27	70.05
Jul-10	2010	Q3	19,719.17		$ 1,670.96	21,390.12	0.89%	14.63	84.68
Aug-10	2010	Q3	21,390.12		$ 1,670.96	23,061.08	0.89%	15.86	100.54
Sep-10	2010	Q3	23,061.08		$ 1,670.96	24,732.03	0.89%	17.10	117.65
Oct-10	2010	Q4	24,732.03		$ 1,670.96	26,402.99	1.20%	24.73	142.38
Nov-10	2010	Q4	26,402.99		$ 1,670.96	28,073.94	1.20%	26.40	168.78
Dec-10	2010	Q4	28,073.94		$ 1,670.96	29,744.90	1.20%	28.07	196.85
Jan-11	2011	Q1	29,744.90		$ 1,736.44	31,481.34	1.47%	36.44	233.29
Feb-11	2011	Q1	31,481.34		$ 1,736.44	33,217.78	1.47%	38.56	271.86
Mar-11	2011	Q1	33,217.78		$ 1,736.44	34,954.22	1.47%	40.69	312.55
Apr-11	2011	Q2	34,954.22		$ 1,736.44	36,690.67	1.47%	42.82	355.37
May-11	2011	Q2	36,690.67		$ 1,736.44	38,427.11	1.47%	44.95	400.31
Jun-11	2011	Q2	38,427.11		$ 1,736.44	40,163.55	1.47%	47.07	447.39
Jul-11	2011	Q3	40,163.55		$ 1,736.44	41,899.99	1.47%	49.20	496.59
Aug-11	2011	Q3	41,899.99		$ 1,736.44	43,636.44	1.47%	51.33	547.91
Sep-11	2011	Q3	43,636.44		$ 1,736.44	45,372.88	1.47%	53.45	601.37
Oct-11	2011	Q4	45,372.88		$ 1,736.44	47,109.32	1.47%	55.58	656.95
Nov-11	2011	Q4	47,109.32		$ 1,736.44	48,845.76	1.47%	57.71	714.66
Dec-11	2011	Q4	48,845.76		$ 1,736.44	50,582.21	1.47%	59.84	774.50
Jan-12	2012	Q1	50,582.21			50,582.21	1.47%	61.96	836.46
Feb-12	2012	Q1	50,582.21			50,582.21	1.47%	61.96	898.42
Mar-12	2012	Q1	50,582.21			50,582.21	1.47%	61.96	960.39
Apr-12	2012	Q2	50,582.21			50,582.21	1.47%	61.96	1,022.35
May-12	2012	Q2	50,582.21			50,582.21	1.47%	61.96	1,084.31
Jun-12	2012	Q2	50,582.21			50,582.21	1.47%	61.96	1,146.27
Jul-12	2012	Q3	50,582.21			50,582.21	1.47%	61.96	1,208.24
Aug-12	2012	Q3	50,582.21			50,582.21	1.47%	61.96	1,270.20
Sep-12	2012	Q3	50,582.21			50,582.21	0.00%	-	1,270.20
Oct-12	2012	Q4	50,582.21			50,582.21	0.00%	-	1,270.20
Nov-12	2012	Q4	50,582.21			50,582.21	0.00%	-	1,270.20
Dec-12	2012	Q4	50,582.21			50,582.21	0.00%	-	1,270.20
				$ -	$ 50,582.21	$ 50,582.21			

Ontario Energy Board
Smart Meter Model

Cooperative Hydro Embrun Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ -	$ -	$ -	$ -	4.37%	$ -
2007	$ -	$ -	$ -	$ -	4.73%	$ -
2008	$ -	$ -	$ -	$ -	3.98%	$ -
2009	$ -	$ 9,693.43	$ 9,693.43	$ 4,846.72	1.14%	$ 55.13
2010	$ -	$ 20,051.46	$ 29,744.90	$ 19,719.17	0.80%	$ 157.26
2011	$ -	$ 20,837.31	$ 50,582.21	$ 40,163.55	1.47%	$ 590.40
2012	$ -	$ 21,029.92	$ 71,612.13	$ 61,097.17	1.47%	$ 898.13
Cumulative Interest to 2011						$ 802.80
Cumulative Interest to 2012						$ 1,700.92

Ontario Energy Board

Smart Meter Model

Cooperative Hydro Embrun Inc.

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
X	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ -	$ -	$ 21,408.41	$ 42,148.22	$ 42,257.45	$ 41,337.31	$ 147,151.40
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ -	$ -	$ 31.91	$ 164.95	$ 577.64	$ 495.71	$ 1,270.20
X Sheet 8A (Interest calculated on monthly balances)	$ -	$ -	$ -	$ 31.91	$ 164.95	$ 577.64	$ 495.71	$ 1,270.20
Sheet 8B (Interest calculated on average annual balances)								$ -
SMFA Revenues (from Sheet 8)	$ 2,659.19	$ 5,952.44	$ 6,134.11	$ 15,453.44	$ 27,427.75	$ 32,190.22	$ 10,400.00	$ 100,217.15
SMFA Interest (from Sheet 8)	$ 22.89	$ 258.10	$ 443.29	$ 199.88	$ 352.88	$ 1,071.37	$ 950.30	$ 3,298.71
Net Deferred Revenue Requirement	-$ 2,682.08	-$ 6,210.54	-$ 6,577.40	$ 5,787.00	$ 14,532.54	$ 9,573.50	$ 30,482.71	$ 44,905.74
Number of Metered Customers (average for 2012 test year)							1958	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		1
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011 plus Interest on OM&A and Amortization		$ 107,084.29
SMFA Revenues collected from 2006 to 2012 test year (inclusive) Plus Simple Interest on SMFA Revenues		$ 103,515.86
Net Deferred Revenue Requirement		$ 3,568.43
SMDR	May 1, 2012 to April 30, 2013	$ 0.15
Check: Forecasted SMDR Revenues		$ 3,524.40

Match

Calculation of Smart Meter Incremental Revenue Requirement Rate Rider (per metered customer per month)

Incremental Revenue Requirement for 2012	$ 41,337.31
SMIRR	$ 1.76
Check: Forecasted SMIRR Revenues	$ 41,352.96

Match

Cooperative Hydro Embrun Inc.

	2009	2010	2011		Total 2009 to 2011	Explanation Allocator	ID and Factors	Total	Residential	General Service Less than 50 kW
Revenue Requirement for the Historical Years	$21,440.32	$42,313.17	$43,330.80		$107,084.29					
Total Return on Capital	$10,411.05	$20,421.67	$19,758.47		$50,591.19	Smart Meter - Capital	CWMC	100.00%	75.29%	19.73%
					Allocated per Class			$50,591.19	$38,089.94	$9,981.93
Amortization	$9,725.34	$20,216.41	$21,910.66		$51,852.41	Smart Meter - Capital	CWMC	100.00%	75.29%	19.73%
					Allocated per Class			$51,852.41	$39,039.51	$10,230.78
Operating Expenses	$0.00	$0.00	$0.00		$0.00	Number of Smart Meters Installed for each Class		1,970	1,796	162
					Allocated per Class			$0.00	$0.00	$0.00
Grossed-up Taxes/PILs	$1,303.93	$1,675.09	$1,661.67		$4,640.69	Revenue Requirement allocated to each Class before PILs		$102,443.60	$77,129.45	$20,212.71
					Allocated per Class			$4,640.69	$3,493.96	$915.63
								Total	Residential	General Service Less than 50 kW
TOTAL REVENUE REQUIREMENT					$107,084.29			$107,084.29	$80,623.41	$21,128.35
					Percentage of costs allocated to Residential and GS < 50 kW customer classes			100.00%	75.29%	19.73%
				Revenue Generated from Smart Meter Funding Adder	$103,515.86					
				Revenues Generated from SMFA	$103,515.86				$ 94,372.83	$ 8,512.47
				Net Deferred Revenue Requirement	$3,568.43					
					Allocated per Class			$3,568.43	-$13,749.43	$12,615.88
					Number of Metered Customers		(2012)		1,796	162
				Smart Meter Disposition Rate Rider					-$0.96	$9.73

Smart Meter Funding Adder Revenues		Number of customers			Estimated SMFA Revenues			
Year	Residential	GS < 50 kW	Other Metered Customer Classes	Residential	GS < 50 kW	Other Metered Customer Classes	Total
2006 (May 1, 2006)	1,796	162	12	**$ 2,445.19**	**$ 220.56**	**$ 16.34**	$ 2,682.08
2007	1,796	162	12	**$ 5,661.99**	**$ 510.71**	**$ 37.83**	$ 6,210.54
2008	1,796	162	12	**$ 5,996.45**	**$ 540.88**	**$ 40.07**	$ 6,577.40
2009	1,796	162	12	**$ 14,270.74**	**$ 1,287.23**	**$ 95.35**	$ 15,653.32
2010	1,796	162	12	**$ 25,326.91**	**$ 2,284.50**	**$ 169.22**	$ 27,780.63
2011	1,796	162	12	**$ 30,323.76**	**$ 2,735.22**	**$ 202.61**	$ 33,261.59
2012 (to March 30, 2012)	1,796	162	12	**$ 10,347.79**	**$ 933.37**	**$ 69.14**	$ 11,350.30
				$ 94,372.83	$ 8,512.47	$ 630.55	$ 103,515.86

Cooperative Hydro Embrun Inc.

	2012		Total 2012	Explanation Allocator	ID and Factors	Total	Residential	General Service Less than 50 kW
Revenue Requirement for the Historical Years	$41,337.31		**$41,337.31**					
Total Return on Capital	$18,439.42		**$18,439.42**	Smart Meter - Capital	CWMC	100.00%	75.29%	19.73%
			Allocated per Class			$18,439.42	$13,882.98	$3,638.21
Amortization	$21,029.92		**$21,029.92**	Smart Meter - Capital	CWMC	100.00%	75.29%	19.73%
			Allocated per Class			$21,029.92	$15,833.36	$4,149.33
Operating Expenses	$0.00		**$0.00**	Number of Smart Meters Installed for each Class		1,970	1,796	162
			Allocated per Class			$0.00	$0.00	$0.00
Grossed-up Taxes/PILs	$1,867.96		**$1,867.96**	Revenue Requirement allocated to each Class before PILs		$39,469.35	$29,716.34	$7,787.53
			Allocated per Class			$1,867.96	$1,406.38	$368.56
						Total	**Residential**	**General Service Less than 50 kW**
TOTAL REVENUE REQUIREMENT			**$41,337.31**			**$41,337.31**	**$31,122.72**	**$8,156.09**
			Percentage of costs allocated to Residential and GS < 50 kW customer classes			100.00%	75.29%	19.73%
			Number of Metered Customers		(2012)		1,796	162
		Smart Meter Disposition Rate Rider					$1.44	$4.20

CHEI Smart Meter Disposition

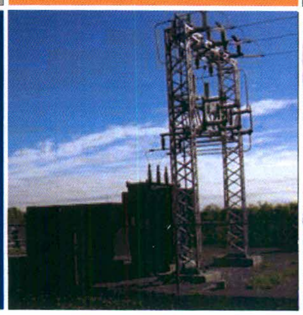
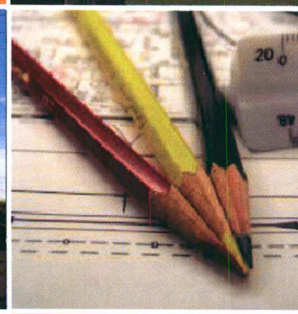
Rate Class	SMDR Eight Month Recovery	SMIRR
Residential	($0.96)	$1.44
General Service Less than 50 kW	$9.73	$4.20
General Service Greater than 50 kW	$48.98	$14.30

Appendix C – System Load-Flow and Optimization Study

System Load-Flow and Optimization Study

for the

Coopérative Hydro D'Embrun Inc. at 821 Notre Dame, Embrun, Ontario


Stantec

One Team.
Infinite Solutions.

Prepared for:
Coopérative Hydro D'Embrun Inc.
821 Notre Dame
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1505 Laperriere Avenue
Ottawa Ontario, K1Z 7T1

May 10, 2011

Final Copy

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INTRODUCTION

UTILITY LOAD FLOW STUDY

Stantec Consulting Ltd. is pleased to submit this Utility Load Flow Study of the electrical distribution system of the Cooperative Hydro D'Embrun Inc. This study has been prepared in accordance with relevant standards, including the Ontario Electrical Safety Authority (ESA), National Electrical Manufacturer's Association (NEMA), Institute of Electrical and Electronic Engineers (IEEE), Municipal Electrical Association (MEA), Canadian Standards Authority (CSA), and the American National Standards Institute (ANSI).

OBJECTIVES

There were a number of objectives for this study, including:

- Determining the acceptability of the system with current and future load growth, including loading that has been recently defined for the next 10 year period from 2010 to 2020
- Finding whether the system would operate acceptably during emergency situations.
- Optimizing the system arrangement (cable sizes, load balancing, open points, etc.) to minimize losses, maximize voltage support, and to distribute loading evenly.
- To determine the optimal placement of a future transformer to allow for substation redundancy and peak loading support.

SCOPE OF STUDY

The Load Flow Study includes all feeders from and including the 44kV Utility Substation down to each major tap at the 8.32(4.8)kV level, no secondary lines were included. All loads were represented as distributed loads over the segment that they were modelled on, and are shown on the system model layout under Appendix 1.

ASSUMPTIONS AND GENERALIZATIONS

A number of assumptions and generalizations are made when modelling a complex system. Some of the ones made in this study are as follows:

- Loads are modelled as distributed across the section of line, sized using measurements made at strategic points within the system during the first study in 2005/2006, which are not anticipated to have changed significantly in the meantime, except for the known service and loading additions.
- Each feeder's loads were modelled at a Power Factor of 0.9.
- The drawing 'Utility Single Line Diagram' completed on March 17, 2005 was used as the basis of the system model, with site inspections completed in 2005 to determine loading and feeder sizes. There was one possible error in the drawing that should be reviewed:

    1. The transformers #477-75 and #476-75 on Centenaire Street are probably located on the R phase by our measurements. This should be reconfirmed by another set of measurements in the future and the drawings updated.

STUDY FINDINGS

DISTRIBUTION SYSTEM EQUIPMENT RATINGS

The main equipment within the Embrun Hydro substation is listed below, along with the ratings that are used to evaluate these components for various loading scenarios.

System Component	***Rating***	***Ampacity @ 8.32kV (44kV)***
44kV Primary Switch	Continuous Amps	3173A (600A)
44kV Primary Fuses S&C Electric SMD-1A, 175E Standard Speed TCC 153-1	Continuous Amps Daily 8 hour peak Emergency 8 hour peak	1015A (192A) 1037A (196A) 1185A (224A)
44,000/8,320V Transformer Delta/Wye (Grnd.), Z = 6.4% 7.5/10MVA, ONAN/ONAF	Continuous Amps ONAN rating Continuous Amps ONAF rating	520A (98A) 693A (131A)
8.32kV Secondary Switchgear Rated Voltage15kV, 1200A, 95kV BIL	Continuous Amps	1200A
8.32kV Feeder Switches, S&C Alduti	Continuous Amps	600A
8.32kV Feeder Fuses S&C SM-5, 300E Standard Speed TCC 153-1	Continuous Amps Daily 8 hour peak Emergency 8 hour peak	300A 306A 320A

Note that the limiting capacity within the substation is the transformer, with a 8.32kV rating of 520A without fans, and 693A with the fans operating. The feeders are each rated for a continuous loading of 300A, or a total of 900A for all three feeders combined.

The various conductors within the distribution system are also rated below. Please note, while insulated cables have a fairly limited set of current ratings (typically free air, raceway, or direct buried ratings), ACSR cables have a wide range of ratings, based on ambient temperatures, peak conductor temperatures, cross winds, emissivity of the conductor, and sun heating. The following conductor ratings are standard ratings, based on maximum absolute conductor temperatures of 105°C, ambient temperatures of 30°C (Summer) and 10°C (Winter), 0.6 m/sec (2 feet/sec) of cross wind, 0.7 coefficient of emissivity, and full sun.

Cable Type	***Rating***	***Ampacity @ 30°C Ambient***	***Ampacity @ 10°C Ambient***
Cable - 350 MCM 1/C CU XLP 100%	Continuous Amps	461	461
Cable - 2/0 AWG 1/C Alum TR-XLP 100%	Continuous Amps	245	245
ACSR - 336 kcmil 26/7	Continuous Amps	647	733
ACSR - 3/0 AWG	Continuous Amps	370	419
ACSR - 1/0 AWG	Continuous Amps	288	326
ACSR - #2 AWG	Continuous Amps	228	285
ACSR - #4 AWG	Continuous Amps	172	215

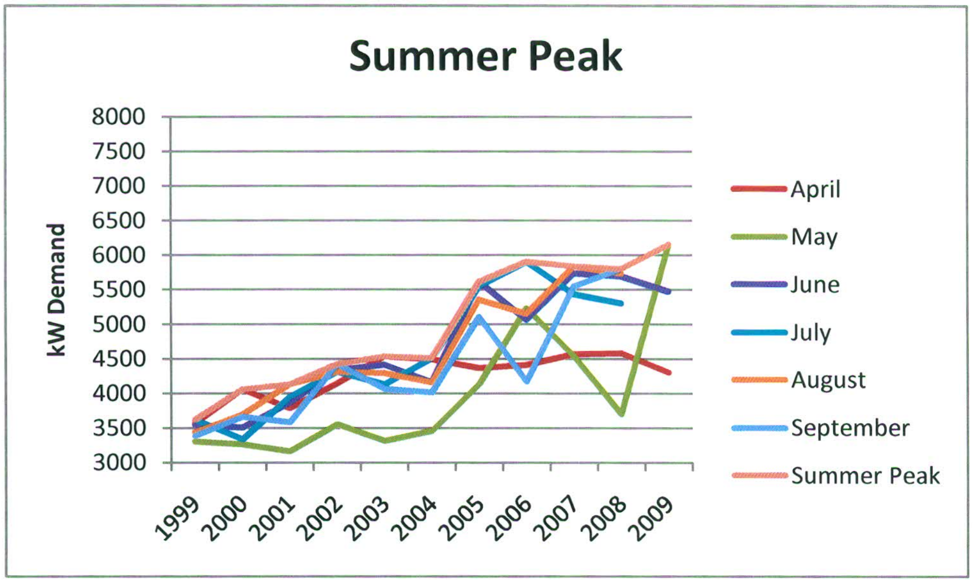
Most feeder level switches within this system are rated for either 100 or 200 Amps, with various fusing used, typically in the range of 70 to 100 Amps. Most main line (F1/F2/F3 trunk) feeder switches are either 200 or 300 Amps, with solid blades. The largest feeder switches are at least 300 Amps, and are currently evaluated as 300 amps, to ensure that all normal and emergency situations which may be above that level are flagged properly. Typically winter ratings of these switches are at least 25% higher than summer ratings due to the lower ambient temperature, and are rated that way within this study. It would be beneficial to add all confirmed switch and fuse ampacities to the system utility diagram at some point in the future. The switches S#818, S#819, and S#822 are modelled as 200 Amp units, S#809 as a 300 Amps, and the F1, F2, and F3 feeder dip pole and ties have been modelled as 600 Amp switches.

DISTRIBUTION SYSTEM LOADING

The study is based on current measurements taken within all the main feeders of the system on May 26, 2005 during normal business hours, and the total measured was 2,820 kVA. Typically, system peaks with heavy residential loads occur early morning and later afternoon/evening, and thus these readings are extrapolated for summer and winter peak monthly loading to evaluate worst case conditions. Using billing data from Embrun Hydro we can see the peak monthly demand loading in the following graph:

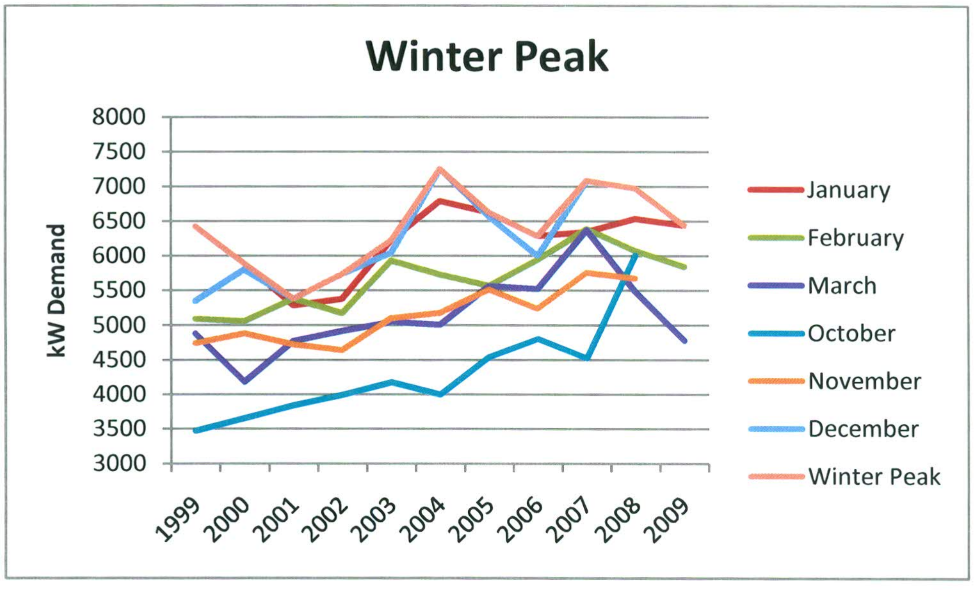
	1999	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*Max*
January	6,422	5,886	5,281	5,372	6,221	6,790	6,624	6,286	6,346	6,531	6,862	6,436	6,862
February	5,087	5,055	5,378	5,173	5,926	5,725	5,565	5,942	6,385	6,068	6,326	5,838	6,385
March	4,877	4,177	4,770	4,914	5,043	5,008	5,562	5,519	6,372	5,485	5,808	4,779	6,372
April	3,562	4,055	3,784	4,138	4,528	4,486	4,358	4,407	4,562	4,576	4,779	4,294	4,779
May	3,300	3,260	3,160	3,549	3,312	3,459	4,132	5,231	4,536	3,699	3,963	6,149	6,149
June	3,539	3,503	3,865	4,333	4,410	4,160	5,611	5,065	5,730	5,687	5,731	5,467	5,731
July	3,620	3,335	3,946	4,310	4,125	4,509	5,548	5,902	5,433	5,304	4,839		5,902
August	3,439	3,690	4,127	4,310	4,285	4,154	5,350	5,155	5,833	5,730	6,052		6,052
September	3,384	3,658	3,581	4,419	4,061	4,013	5,108	4,169	5,545	5,793	4,428		5,793
October	3,469	3,648	3,839	3,990	4,173	3,994	4,539	4,801	4,519	6,005	4,719		6,005
November	4,735	4,876	4,718	4,637	5,098	5,174	5,509	5,237	5,754	5,672	5,464		5,754
December	5,346	5,801	5,371	5,731	6,042	7,251	6,558	5,998	7,084	6,974	6,854		7,251
Annual Peak	6,422	5,886	5,378	5,731	6,221	7,251	6,624	6,286	7,084	6,974	6,862	6,436	7,251

Using the maximums from this table gives a baseline value of 6,149kW for Summer Peak Demand and 7,251kW for Winter Peak Demand for 2010. The peaks are also graphed below to see the individual monthly loading trends over the years:



As can be seen, summer peaks have steadily climbed over the years because of system growth and other items such as air conditioning and pool installations. In 2005/2006 the peak substantially increased as a function of infill and new housing developments that occurred in that time period.

The following graph shows winter peaks, which are typically a function both of load growth and winter temperature, since improved energy efficiency and transitioning from baseboard heating to forced air helps offset system growth. Most new houses usually have natural gas heating, and thus do not represent a significant additional winter load, unlike older electrically heated houses.



The distribution of loads within the system will not have changed substantially since they were initially measured, except for known service and loading additions. Thus we scale the base loading measurements of 2005 to the summer and winter peak values of 6,832 kVA (or 6,149 kW) and 8,057 kVA (or 7,251 kW) respectively. Please note, all three feeders were scaled equally, however, Feeder F1 with more of its load as commercial vs. the majority residential elsewhere, may have some natural balancing since commercial will typically peak during the day, while residential will peak in mornings and late afternoons. However, this effect was not evaluated since we did not have any daily feeder trending values to review.

2010 Peak Demand Loading

Feeder	***Phase***	***Amps-Measured***	***kVA - Measured***	***Adj. Amps Summer***	***Adj. KVA - Summer***	***Adj. Amps Winter***	***Adj. kVA - Winter***
Feeder 1	R	71.6	343.7	173.5	832.8	204.6	982.1
	W	75.1	360.5	182.0	873.5	214.6	1030.1
	B	69.3	332.6	167.9	806.0	198.0	950.5
Feeder 2	R	60.1	288.5	145.6	699.0	171.7	824.4
	W	61.5	295.2	149.0	715.3	175.7	843.6
	B	62.5	300.0	151.4	726.9	178.6	857.3
Feeder 3	R	67.6	324.5	163.8	786.2	193.2	927.2
	W	54.3	260.6	131.6	631.6	155.2	744.8
	B	65.4	313.9	158.5	760.7	186.9	897.1
		kVA Total:	2819.5		6832.0		8057.0

As can be seen, the kVA peaks are higher in winter, indicative of substantial electrical baseboard heating in older residential neighbourhoods.

FUTURE LOAD GROWTH

The distribution system and its components must be evaluated both under existing and future loading to properly plan and sequence future capital upgrades. Most municipal utility's loads will grow over time due to a variety of reasons, with the main contributors listed below:

- Existing customers add load (pool pumps, new air conditioners, etc.).
- New developments or single in-fill customers are added within the Utility boundary.
- The Utility boundaries are enlarged.

We are estimating that natural load usage growth of existing customers will be no more than 1% per year. The additional energy usage typical of more air conditioners, computers, TV's, and other electronic goods will be offset by the additional transitioning to energy efficient lighting, baseboard to forced air replacements, replacement of old appliances with new reduced consumption units, and other energy efficient changes.

The client base within Embrun contains 1,756 residential units, 148 commercial units less than 50kW, and 12 commercial units greater than 50kW. As most commercial units are already natural gas heated, we assume the small commercial units are all an average of about 15kW, while the large units are on average 100kW, gives the following kW Demand per unit (based on peak 2010 winter conditions):

- Residential units = 3,831kW total, or 2.18kW/unit (equivalent to 2.42kVA at 0.9PF)
- Smaller Commercial = 15kW/unit, or 2,220kW total
- Large Commercial = 100kW/unit, or 1,200kW total

We assume most developed areas have currently been in-filled close to capacity. However, the following areas are proposed for future in-fill development during the following time periods, with an estimated units/development and the preferred feeder for connection (based on location and existing feeder capacity):

- North of Rue Blais at Notre-Dame: 2011, 40 units, F03
- South-East of St Jacques and the Castor: 2011, 50 units, F02
- North-East of Notre-Dame and Rue Manoir: 2011, 24 units, F02
- South-East of Ste Marie and the Castor: 2012, 291 units, 1 new fire station, F03
- South-East of Ste Marie and Notre-Dame: 2013, 150 units, F03
- South-West of Ste Marie and Notre-Dame: 2014, 72 units, F03

With this proposed development schedule, and each additional residential house at an average peak Demand of 2.18kW or 2.42kVA, the future additional kVA Demand loading forecast for the complete system is shown below:

Period (Demand kVA)	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*
Summer	6,832	6,900	7,245	8,040	8,484	8,743	8,830	8,919	9,008	9,098	9,189
Winter	8,057	8,138	8,495	9,302	9,758	10,030	10,131	10,232	10,334	10,438	10,542
Normal Load Growth	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	
Future Development F02		179									
Future Development F03		97	722	363	174						

Assuming all new future development is added to the local feeder in a method that tends to balance the phases or each feeder, future Summer and Winter peak loading for each feeder would be as follows:

Peak Summer Loading												
Period (Demand kVA)		***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***
Feeder 1	R	173.5	175.2	177.0	178.8	180.5	182.3	184.2	186.0	187.9	189.7	191.6
	W	182.0	183.8	185.6	187.5	189.4	191.3	193.2	195.1	197.1	199.0	201.0
	B	167.9	169.6	171.3	173.0	174.7	176.5	178.3	180.0	181.8	183.7	185.5
Feeder 2	R	145.6	147.1	167.2	168.9	170.6	172.3	174.0	175.7	177.5	179.3	181.1
	W	149.0	150.5	163.2	164.8	166.5	168.1	169.8	171.5	173.2	175.0	176.7
	B	151.4	153.0	161.8	163.4	165.0	166.7	168.4	170.0	171.7	173.5	175.2
Feeder 3	R	163.8	165.4	167.1	218.9	246.3	260.8	263.5	266.1	268.8	271.4	274.2
	W	131.6	132.9	154.4	206.1	233.4	247.8	250.3	252.8	255.3	257.9	260.4
	B	158.5	160.1	161.7	213.4	240.8	255.2	257.8	260.4	263.0	265.6	268.3

Peak Winter Loading												
Period (Demand kVA)		***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***
Feeder 1	R	204.6	206.6	208.7	210.8	212.9	215.0	217.2	219.4	221.6	223.8	226.0
	W	214.6	216.8	218.9	221.1	223.3	225.6	227.8	230.1	232.4	234.7	237.1
	B	198.0	200.0	202.0	204.0	206.1	208.1	210.2	212.3	214.4	216.6	218.7
Feeder 2	R	171.7	173.5	193.8	195.8	197.7	199.7	201.7	203.7	205.8	207.8	209.9
	W	175.7	177.5	190.5	192.4	194.3	196.2	198.2	200.2	202.2	204.2	206.2
	B	178.6	180.4	189.5	191.4	193.3	195.2	197.2	199.2	201.2	203.2	205.2
Feeder 3	R	193.2	195.1	197.1	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
	W	155.2	156.7	178.5	230.4	257.9	272.6	275.3	278.1	280.9	283.7	286.5
	B	186.9	188.8	190.6	242.7	270.3	285.1	288.0	290.8	293.7	296.7	299.7

NORMAL CONDITIONS EVALUATION

LOADING ASSESSMENT

The loading assessment for the distribution with a normal switching configuration and loads from 2010 to 2020 is shown below:

Peak Annual Loading													
Feeder	***Phase***	***Rating***	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***
44kV Switch		3173	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
44kV Fuses		1015	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
44kV Trans. ONAN		520	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
44kV Trans. ONAF		693	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
8.32kV Switchgear		1200	559.1	564.7	589.4	645.4	677.1	695.9	702.9	709.9	717.0	724.2	731.4
8.32kV Feeder Switches		600	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
8.32kV Fuses (Continuous)		300	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
8.32kV Fuses (Daily 8 hour)		306	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
8.32kV Fuses (Daily 8 hour)		320	214.6	216.8	218.9	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
Feeder 1	R	461	204.6	206.6	208.7	210.8	212.9	215.0	217.2	219.4	221.6	223.8	226.0
	W	461	214.6	216.8	218.9	221.1	223.3	225.6	227.8	230.1	232.4	234.7	237.1
	B	461	198.0	200.0	202.0	204.0	206.1	208.1	210.2	212.3	214.4	216.6	218.7
Feeder 2	R	461	171.7	173.5	193.8	195.8	197.7	199.7	201.7	203.7	205.8	207.8	209.9
	W	461	175.7	177.5	190.5	192.4	194.3	196.2	198.2	200.2	202.2	204.2	206.2
	B	461	178.6	180.4	189.5	191.4	193.3	195.2	197.2	199.2	201.2	203.2	205.2
Feeder 3	R	461	193.2	195.1	197.1	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
	W	461	155.2	156.7	178.5	230.4	257.9	272.6	275.3	278.1	280.9	283.7	286.5
	B	461	186.9	188.8	190.6	242.7	270.3	285.1	288.0	290.8	293.7	296.7	299.7

As can be seen, current peak loading of 8,057kVA (winter) is above the capacity of the transformer is fans were not present, but within the capacity of the transformer with fans. Note, the maximum peak is during the winter which is a time of fairly low ambient temperature and would the transformer to provide more overloading than normal. The municipal transformer is now 23 years old, with typical life expectancies ranging from 30-40 years for well maintained oil-filled power transformers. In 2020, the system loading will surpass the ONAF (fan rated) capacity of the single transformer. Within municipal distribution systems some peak overloading is occasionally acceptable, since the peaks are typically short lived (< 4 hours) and not continuous. However, it should be noted that as the age of the transformer increases, the possibility of failure also increases, plus, in areas without sufficient redundancy to back up the primary supply, this becomes risky situation. Redundancy when supplying the Embrun system is already an issue, as the emergency infeeds from Hydro-One may not be sufficient during peak times of the day to support the complete system in the event of the failure of the main transformer. Possible options to provide for this extra capacity, while providing redundancy as well, are evaluated later in the report.

To evaluate the present and future loading on the feeders, the graph shows the proposed load growth added to the feeders that they are near, plus attempting reasonable phase balancing with the additional loads. Since the main conductors for the all three feeder networks are now 336 kcmil, the limiting factor in each circuit becomes the underground 350MCM cable from the substation. As such, the ratings in the table represent the ampacity of these underground cables rather than the main overhead circuit conductors. It can be seen that the loading within the feeder conductors are acceptable, but are reaching the capacity of the feeder fuses, even during normal operation. Therefore, either the fuses would have to be upsized to 400 Amps before 2015, or reconfiguration of the feeders would be required.

All other components within the distribution networks, including switches and conductors, seem to be adequate to support the normal load growth expected through the year 2020.

SYSTEM LOSSES

With the existing nominal system loading of 2,821.6 kVA (losses inclusive), distribution losses (including substation losses) total 10.28 kW, approximately 0.36% of system loading. At peak summer loading of 6,832 kVA, losses total 61.58 kW, approximately 0.90% of system loading. At peak winter loading of 8,057 kVA (losses inclusive), losses total 85.83 kW, approximately 1.07% of system loading.

There were some unbalanced currents as shown in the table that follows, especially on Feeder 3. Keeping the currents in the phases balanced reduces energy losses, as return currents travel through undersized neutrals and the overall inductance of the line is higher.

Feeder	*Phase*	*Amps-Measured*	*Avg.*	*Unb. (%)*	*Preferred Rephasing*	*Final*	*Avg. (%)*
Feeder 1	R	71.6			0.0	71.6	
	W	75.1	72.0	4.3	-3.0	72.1	0.6
	B	69.3			3.0	72.3	
Feeder 2	R	60.1			1.0	61.1	
	W	61.5	61.4	2.1	0.0	61.5	0.4
	B	62.5			-1.0	61.5	
Feeder 3	R	67.6			-5.0	62.6	
	W	54.3	62.4	13.0	8.0	62.3	0.3
	B	65.4			-3.0	62.4	

Possible options to rebalance are as follows:

1. F1: 538-50-W to B
2. F2: 483-50-B to R
3. F3: 430-50-B, and 432-100-R to W

As there have probably been some system changes within the interim time period between the initial measurements, the main feeders should be measured before any changes are implemented to verify that the imbalances remain, if present and similar to those identified within the report, the rebalancing changes could proceed. Note that the future loading additions from 2011 to 2014 would also be good opportunities to rebalance the loading, and may preclude the requirements to change existing distribution arrangements at additional costs.

FEEDER VOLTAGES UNDER NORMAL OPERATION

As per CAN3-C235-83 'Preferred Voltage Levels for AC Systems, 0 to 50,000V' all service entrance voltages should be no less than 91.7% of nominal (110V) and no higher than 104.2% of nominal (125V) during normal operating conditions. During extreme operating conditions the voltages may fall to 88.3% (106V) or rise to 105.8% (127V) of nominal.

Using the existing distribution system configuration, at peak 2010 loading (winter) of 8,057 kVA the worst case feeder voltage is 96.67%. The voltage profile maps can be seen on the relevant graphs under Appendix 2, which show that all voltages are within the acceptable range.

The case of system loading in 2020 winter peaks of 10,542 kVA with the existing substation and three feeders was simulated. The minimum voltage on F3 was 93.18% of nominal, fairly low, but within the acceptable operating range. The minimum voltage of F1 and F2 was 97.47%, well within the acceptable operating range. The voltage profile maps can be seen within Appendix 2.

SYSTEM UPGRADES TO MINIMIZE LOSSES AND SUPPORT VOLTAGE

In 2006 some of the main conductors in the feeder 1 and 2 circuits were changed from 3/0 AWG ACSR to 336 kcmil to reduce overall losses, improve voltage profiles, and improve emergency loading capacities. In particular, for feeder 1, the section from the sub to Notre-Dame and, for feeder 2, the section from the sub to Centenaire, were upgraded to 336 kcmil. These line upgrades has resulted in improved voltage support and a significant reduction in losses in the feeder networks. Assuming average loading of 33% of winter peak loading and costs of $0.10/kWHr, these changes have resulted in an estimated annual savings of about $9,700.

Other suggested changes to the system involve utilizing the switches that interconnect the feeder networks to redistribute the loading between the feeders. Transferring a small amount of load from F3 to F1 by opening S#809 and closing S#812 increases the minimum feeder voltage in the circuit under peak winter loading conditions to 97.1%. Losses are reduced from 85.83 kW to 84.16 kW. This translates into annual savings of $483. No other switch modifications are significant at this time.

Reconductoring the portion of the F1 to F3 link from St-Marie to St-Jacques would be another method to reduce losses, from 85.83 kW to 83.56 kW. This results in annual savings of $656. Although the savings that would result from this last change are more significant than that achieved from switching open points on the feeders, on a cost/benefit basis, reconductoring this portion of the line would not be recommended. There would be major effort required to upgrade this portion of the line to 336 kcmil, whereas the load transfer changes are simple to implement as a result of the switches that interconnect the feeder networks, and well worth the effort even for the relatively small annual savings that would be achieved.

EMERGENCY CONDITIONS EVALUATION

FEEDER CONFIGURATIONS DURING EMERGENCY CONDITIONS

The following scenarios are provided to show the loading and voltage results across the system as a result of the loss of each feeder in turn. Simple switching results are shown first, followed by more complex switching if required.

Scenario 1 – Loss of F1, use F2 to feed F1 circuit (i.e. open S#833, close S#829)

Peak Summer Loading													
Feeder	***Phase***	***Rating***	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***
8.32kV Feeder Switches		600	390.3	394.2	409.4	413.5	417.6	421.8	426.0	430.3	434.6	438.9	443.3
8.32kV Fuses		300	390.3	394.2	409.4	413.5	417.6	421.8	426.0	430.3	434.6	438.9	443.3
8.32kV Fuses (Daily 8		306	390.3	394.2	409.4	413.5	417.6	421.8	426.0	430.3	434.6	438.9	443.3
8.32kV Fuses (Daily 8		320	390.3	394.2	409.4	413.5	417.6	421.8	426.0	430.3	434.6	438.9	443.3
Feeder 1	R	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder 2	R	461	376.3	380.1	402.6	406.6	410.6	414.8	418.9	423.1	427.3	431.6	435.9
	W	461	390.3	394.2	409.4	413.5	417.6	421.8	426.0	430.3	434.6	438.9	443.3
	B	461	376.6	380.4	391.5	395.4	399.4	403.4	407.4	411.5	415.6	419.7	423.9
Feeder 3	R	461	193.2	195.1	197.1	249.2	276.9	291.7	294.6	297.6	300.6	303.6	306.6
	W	461	155.2	156.7	178.5	230.4	257.9	272.6	275.3	278.1	280.9	283.7	286.5
	B	461	186.9	188.8	190.6	242.7	270.3	285.1	288.0	290.8	293.7	296.7	299.7

As can be seen, this scenario is unacceptable, due to overloading on the feeder fuse. Even if replaced with a 400 Amp fuse, this scenario still results in overloading by 2012.

If we shift the section of F1 and F2 West of St. Jacques to F3 by opening S#814 and closing S#811, and then opening S#818 and closing S#821, the following loading levels are achieved.

Peak Summer Loading													
Feeder	***Phase***	***Rating***	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***
8.32kV Feeder Switches		600	290.3	-	-	-	-	-	-	-	-	-	455.1
8.32kV Fuses		300	290.3	-	-	-	-	-	-	-	-	-	455.1
8.32kV Fuses (Daily 8		306	290.3	-	-	-	-	-	-	-	-	-	455.1
8.32kV Fuses (Daily 8		320	290.3	-	-	-	-	-	-	-	-	-	455.1
Feeder 1	R	461	0.0	-	-	-	-	-	-	-	-	-	0.0
	W	461	0.0	-	-	-	-	-	-	-	-	-	0.0
	B	461	0.0	-	-	-	-	-	-	-	-	-	0.0
Feeder 2	R	461	184.4	-	-	-	-	-	-	-	-	-	209.8
	W	461	184.2	-	-	-	-	-	-	-	-	-	199.3
	B	461	208.6	-	-	-	-	-	-	-	-	-	218.8
Feeder 3	R	461	290.3	-	-	-	-	-	-	-	-	-	420.7
	W	461	290.1	-	-	-	-	-	-	-	-	-	455.1
	B	461	271.0	-	-	-	-	-	-	-	-	-	396.7

As can be seen, this scenario is marginally acceptable in 2010, due to the unbalanced loading between F2 and F3. Some load changes could be done to balance the loading to ensure avoidance of the 300 Amp fuse, plus the fuse could be replaced with a 400A unit. However, by 2020, the total loading of the F3 fuse would exceed 400 Amps, requiring further switching to balance the feeders.

In 2010, the worst case voltage level within F3 is 93.16%, and the worst case voltage level within F2 is 98.13%, both within acceptable ranges. By 2020, the worst case voltage level within F3 is 89.61%, and the worst case voltage level within F2 is 97.45%, within extreme and normal operating ranges respectively, acceptable for emergency operation.

No other conductors would be overdutied within the system for this switching pattern, except for the possible exception of Switch S#805 which may only be rated for 100 Amps, but taking close to 210 Amps. *Therefore, to handle emergency switching, we would recommend that all main trunk switches on F1, F2, and F3 north of the Castor should be confirmed to be at least 300 Amps (i.e. S#805, S#819, S#818, S#814, etc.). All main trunk switches on F1, F2, and F3 south of the Castor should be confirmed to be at least 600 Amps.*

Scenario 2 – Loss of F2, use F1 to feed F2 circuit (i.e. open S#834, close S#829).
Then shift the section of F1 and F2 West of St. Jacques to F3 by opening S#814 and closing S#811, and then opening S#818 and closing S#821

These results are identical to Scenario 1 above.

Scenario 3 – Loss of F3, use F2 to feed F3 circuit (i.e. open S#835, close S#821).

Peak Annual Loading													
Feeder	Phase	Rating	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8.32kV Feeder Switches		600	365.5	369.1	390.9	444.9	474.6	491.4	496.3	501.3	506.3	511.4	516.5
8.32kV Fuses		300	365.5	369.1	390.9	444.9	474.6	491.4	496.3	501.3	506.3	511.4	516.5
8.32kV Fuses (Daily 8		306	365.5	369.1	390.9	444.9	474.6	491.4	496.3	501.3	506.3	511.4	516.5
8.32kV Fuses (Daily 8		320	365.5	369.1	390.9	444.9	474.6	491.4	496.3	501.3	506.3	511.4	516.5
Feeder 1	R	461	204.6	206.6	208.7	210.8	212.9	215.0	217.2	219.4	221.6	223.8	226.0
	W	461	214.6	216.8	218.9	221.1	223.3	225.6	227.8	230.1	232.4	234.7	237.1
	B	461	198.0	200.0	202.0	204.0	206.1	208.1	210.2	212.3	214.4	216.6	218.7
Feeder 2	R	461	364.9	368.6	390.9	444.9	474.6	491.4	496.3	501.3	506.3	511.4	516.5
	W	461	330.9	334.2	369.0	422.8	452.2	468.8	473.5	478.2	483.0	487.9	492.7
	B	461	365.5	369.1	380.1	434.1	463.6	480.3	485.1	490.0	494.9	499.8	504.8
Feeder 3	R	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

As can be seen, this scenario is unacceptable, due to overloading on the feeder fuse. Even if replaced with a 400 Amp fuse, this scenario still results in overloading by 2013 on the feeder fuse and by 2014 on various conductors within the system. The underground cable from the substation is also overloaded by 2014, while the section of overhead and underground line along F2 from the corner of Notre-Dame and Rue Blais over to St-Jacques is also overloaded (1/0 AWG overhead line rated at 288 Amps, but loaded at 305 Amps, 2/0 AWG underground line rated at 245 Amps, but loaded at 348.3 Amps).

In 2010, the worst case voltage level within F2 is 92.15%, and the worst case voltage level within F2 is 97.84%, both within acceptable ranges. By 2020, the worst case voltage level within F3 is 87.46%, and the worst case voltage level within F2 is 97.84%. Thus the terminal F3 voltage is thus below acceptable voltages even for emergency situations.

If we use the Hydro-One west end emergency supply to reduce the loaded in the North-West quadrant by opening switches S#810, S#809, and S#806, and closing switches S#807, S#803, and S#800, we reduce our overall loading by about 88 Amps, which is within the 250 Amps allowable for this emergency supply. We could not off-load the full F3 feeder since the loading is about 300 Amps. This gives an approximate graph below:

Peak Annual Loading

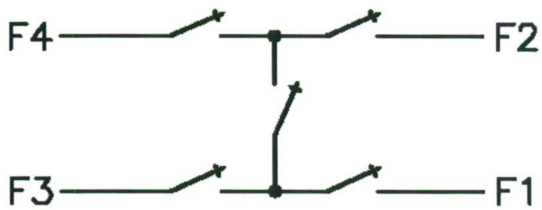
Feeder	Phase	Rating	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8.32kV Feeder Switches		600	277.5	281.1	302.9	356.9	386.6	403.4	408.3	413.3	418.3	423.4	428.5
8.32kV Fuses		300	277.5	281.1	302.9	356.9	386.6	403.4	408.3	413.3	418.3	423.4	428.5
8.32kV Fuses (Daily 8		306	277.5	281.1	302.9	356.9	386.6	403.4	408.3	413.3	418.3	423.4	428.5
8.32kV Fuses (Daily 8		320	277.5	281.1	302.9	356.9	386.6	403.4	408.3	413.3	418.3	423.4	428.5
Feeder 1	R	461	204.6	206.6	208.7	210.8	212.9	215.0	217.2	219.4	221.6	223.8	226.0
	W	461	214.6	216.8	218.9	221.1	223.3	225.6	227.8	230.1	232.4	234.7	237.1
	B	461	198.0	200.0	202.0	204.0	206.1	208.1	210.2	212.3	214.4	216.6	218.7
Feeder 2	R	461	276.9	280.6	302.9	356.9	386.6	403.4	408.3	413.3	418.3	423.4	428.5
	W	461	242.9	246.2	281.0	334.8	364.2	380.8	385.5	390.2	395.0	399.9	404.7
	B	461	277.5	281.1	292.1	346.1	375.6	392.3	397.1	402.0	406.9	411.8	416.8
Feeder 3	R	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	W	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	B	461	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

As can be seen, this scenario is still unacceptable, due to overloading on the feeder fuse. Even if replaced with a 400 Amp fuse, this scenario still results in overloading by 2015 on the feeder fuse and before 2020 on various conductors within the system, primarily the section of underground line along F2 between St-Jean-Baptiste to St-Jacques is also overloaded (2/0 AWG underground line rated at 245 Amps, but loaded at 260.3 Amps). A concern is that the Hydro-One emergency supplies may be taken back at some point by Hydro-One to supply their own loading, thus removing this potential option of assisting with the supply of F3 in emergency situations.

Therefore, reviewing the previous scenarios, we can determine that the main weakness within the system is the single F3 conductor to the north-west quadrant. Additional loading will result in that feeder being heavily loaded, and susceptible to significant problems in single point failure conditions, especially as the emergency supplies are limited to either F1 or F2 through smaller 1/0 or 3/0 overhead conductors (at the intersection of Notre-Dame and Rue Blais)

There will also be future problems with any 300A switches around the southern portion of the main loop (i.e. at the source ends, S#833, 834, 835, possibly S#888 and 814) and with the 300E fuses protecting each feeder. While it may be possible to upgrade the switches to 400A or 600A units (or confirm that the switches are capable of handling those types of loads on an emergency basis), and install 400E fuses, this may also cause problems with upstream coordination (i.e. the transformer primary fuse) and with downstream devices during overload conditions.

Therefore, to avoid these problems, and to mitigate the problems identified within the system, we would recommend that a 4th feeder be added to reduce these emergency switching overload conditions. The worse existing case is the failure of Feeder 3 when split on F1 and F2, thus we would recommend the installation of Feeder 4 along the routing of F3, with the bulk of new loads in the F3 vicinity installed on F4. This would also complete a loop of 2 feeders around the main distribution points of Embrun. Therefore, any single pole outage which could potentially knock out 2 feeders at one time would leave ½ of the Embrun distribution capacity in operation. With temporary emergency infeeds from the Hydro-One distribution, this would be sufficient to get through short emergency operations. We would recommend that the interconnection between feeders to be properly phased and completed with the following configuration to allow a dual loop interconnection as required:



To minimize costs, all new loading would then be placed on F4, although if rebalancing was preferred quickly, existing loads could be moved over the F4 whenever required, to balance F3 and F4 and minimize losses and improve emergency switching.

RECOMMENDATIONS

SUBSTATION REDUNDANCY & CAPACITY

From the previous findings, it is possible that the capacity of the main transformer for ONAF (fan-rated) capacity will be surpassed in 2015 in the winter, but not till after 2020 in the summer, with the ONAN (non-fan rated) already being surpassed in the winter, but also being surpassed in 2013 in summer. It is recommended that digital meters be installed on the three feeders to provide much more accurate metering of the loading during various peak periods. This will allow further detailed evaluation of the effects of the loading upon the transformer as this time is approaching. However, the issue of absolute transformer capacity will have to be resolved within the next few years as development continues within the Embrun boundaries.

The issue of redundancy is also problematic. Currently, if the transformer fails, the only short term solutions would be as follows:

- Use the Emergency Hydro-One infeeds from East and West (discussed further under Option 1)
- Borrow or purchase a used transformer from another Utility or Surplus Equipment Dealer
- Borrow a Hydro-One Mobile Unit Substation (MUS)

Borrowing or purchasing a used transformer would be a difficult option if it had not been arranged beforehand. The costs to have an option on a spare transformer could be substantial, plus the costs and time to transport and install a transformer would be significant. This is not an optimal solution and would not be recommended.

Another high risk option is to hope to borrow a Hydro-One MUS unit. Hydro-One in the past had an official program to provide emergency access to one of these units for an annual fee (i.e. about $10,000 ten years ago). Today, they may agree to lend a unit during an emergency, however, this is completely dependant on them having a spare available, plus there is no guarantee that it would be available for the duration that it is required, since these are regularly used by Hydro for their own emergency and maintenance requirements. There would also be substantial costs associated for the use of one of these units (if available) since specific reconfiguration of a substation has to be done to allow one of these to be connected to the system easily. These costs are estimated at about $25,000 of hard costs, plus another $25,000 of Hydro-One soft costs, plus an estimated "rental" fee of $7,000 per week, or about $260,000 for a typical 30 week emergency transformer replacement period. Therefore, we would not recommend relying on this option.

Option 1: Continue Using Hydro-One Infeeds from east and west

The current method of providing the required redundancy is by using a feeder from each of the Hydro-One substations located to the east and west of Embrun. Each of the two feeders could provide support for 3.6 MVA of loading on an 'as required' basis. Using this method as a temporary way to provide the required redundancy means that the purchase of a second transformer or construction of another substation could be deferred until required for capacity reasons. This current agreement lasts till 2011; Hydro-One has confirmed that they can extend this agreement for another 5 years, with 2 year renewal periods afterwards.

2010 winter peak loading conditions were simulated with the existing substation out of service. The entire load was serviced by a feeder on the west side, connected to the system at switch S#800, and a feeder on the east side, connected at switch S#844. The main switch configuration was as follows:

- Open F1, F2, and F3 feeder switches (Isolate Embrun sub from distribution system)
- Open S#818, close S#821 (transformer some load to F3)
- Close S#845 (connect F2 to F1)
- Close S#800 and S#844 (tie both F3 and F1/F2 to Hydro-One)

Voltage and load profile maps are included in Appendix 2 and Appendix 3, respectively. The worst case feeder voltage in the system was found to be 90.53% of nominal, which is above the minimum acceptable for emergency conditions, and there are no overloaded switches or conductors in the system. However, the power that can be supplied from each of the feeders is limited to the 250 Amps of firm capacity allowed by the 280A reclosers on each circuit, meaning each feeder can supply 3.6 MVA of continuous loading for a total of 7.2 MVA. Winter peak loading at present is 8,057 kVA (although non-continuous loading), which is just beyond the combined capacity of the two feeders. Therefore, a small amount of load shedding may need to be implemented during the few peaks in winter that reach 8MVA while being supported by Hydro-One. The loading on the East supply with the above switching configuration is 333.1/332.5/325.5 on R/W/B respectively, and on the West supply is 250.6/251.4/271.4 on R/W/B respectively. By 2020 this loading will be approximately 30% higher, substantially on the East supply, probably balancing out the supplies. Thus the load shedding required in the future would be even more significant.

The costs of this support is a monthly shared DS charge based on peak kW demand per month, and regular kWhr pass-through charges, also determined on a monthly basis. Annual costs from 2010 to 2020 were estimated based on the following assumptions:

- Shared DS charges will be fixed at $1.60/kW for the duration of the agreement
- Typical peak demand during an outage will be 70% of peak winter load
- Typical outage frequency – 1 every other year

While the two extra feeders will provide acceptable redundancy for the system, this is not a permanent solution, as load shedding already has to be done. Within 5 years, peak system loading will be 9,968 kVA, which means only 72% of the system loading will be supported by the Hydro-One emergency in-feeds. Therefore, the continued reliance solely on the Hydro-One emergency in-feeds is not acceptable with the substantial system load additions due to further development in the next five years.

Option 2: Addition of new transformer to existing substation

Redundancy and capacity issues could be addressed by adding a second transformer to the existing substation. Some modifications would be required to the existing substation in order to accommodate a second transformer, as listed in the detailed budget pricing under Appendix 5. The main modifications that may be required are as follows:

- Modifications to the tower structure to accommodate second transformer
- New primary fuses and IPS structures
- Ground Grid may have to be revised
- May want a physical barrier between the two transformers for failure protection
- Second transformer pad and pad for new switchgear
- New secondary switchgear for Transformer 2.

It is estimated that adding a second transformer to the existing substation would cost in the range of $600,000 plus engineering design and taxes. Maintenance costs for the transformer and new switchgear are estimated at $6,000 on a five year cycle.

Option 3: Construction of new substation

System capacity and redundancy could also be improved by adding a second separate substation, probably at Ste Marie street south of the Castor. There are a few marginal improvements by adding a second transformer, as follows:

- Slightly improves redundancy in that a failure at one substation may not affect the operation of the other
- Slightly reduces overall system losses
- Slightly improves voltage support both during normal and emergency operations

However, these advantages are offset by some substantial costs:

- Land costs ($120,000?)
- 44kV Line costs ($160,000?)
- Marginal costs for fencing, stone, and ground grid ($25,000)
- Costs for 2nd phone line for metering ($250/year?)

This option was reviewed in some detail in the 2005/2006 report, and since the benefits are marginal while the additional costs are substantial, this option was not recommended for Embrun Hydro.

FEEDER PROTECTIVE DEVICES

There are some drawbacks with the usage of fused load breaks as the main switching devices for the Embrun feeders.

- Low level intermittent or continuous arcing may not provide enough fault current to clear fuses.
- High fault levels required to clear fuses, possibly resulting in significant damage downstream at the point of faulting.
- Operation of the fuses require operators to replace fuse links, resulting in at least 2 hours of feeder downtime, plus costs of fuse links (typically $800 per set of 3 links).
- Typically, it was reported that at least one fuse link has to be replaced every few years.

If the main distribution system was 100% overhead conductors, it would be recommended to replace the feeder devices with reclosers or medium voltage circuit breakers with recloser relays. The advantage is that typical overhead lines are subject to transient flashovers due to lightning strikes or branch contacts, and that once the initial fault is extinguished, the circuit can be quickly re-closed and re-energized. However, as the municipal distribution system starts transitioning to underground cables on portions of the main feeders and the majority of the residential distribution, the risk of re-closing into cable faults becomes more significant. Typically a recloser will reclose quickly a few times after an initial fault, then if it is still not cleared, give one time-delayed reclose to allow a downstream fuse time to clear for faults downstream of system fuses. However, if this is done on a cable fault, significant damage can occur during the multiple reclose operations.

A medium voltage circuit breaker could also be applied in this application and would have a few advantages over fused loadbreaks. The main advantages of a breaker would be the following:

- Very sensitive protection can be applied, including phase and ground fault protection.
- Other sophisticated protection can be applied, as well as sequence of events records, waveform captures, and metering within the relays
- A breaker can be quickly re-closed after a fault is cleared, unlike fuses which must have their link replaced.

However, a circuit breaker would also cost substantially more than a fused loadbreak, typically about $50,000 versus $15,000 for a single feeder (initial construction costs, not retrofit), with other potential costs such as a battery bank for stored tripping energy and other requirements. Therefore, while there are some advantages to applying this protection, it would not currently be recommended based on the costs involved and the potential future configuration of the system.