EXHIBIT 2 - RATE BASE

EB-2014-0080

Table of Contents

Overview of Rate Base

Ex.2/Tab 1/Sch.1 - Rate Base Overview

HPDC's Rate Base is determined by taking the average of the balances at the beginning and the end of the 2015 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, 2013. The net fixed assets include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. HPDC does not have non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

HPDC has calculated its 2015 rate base to be $2,759,303. This rate base is also used to determine the return on investment component of the Revenue Requirement presented at Ex.6/Tab 1/Sch.7. Table 2.0 below presents HPDC's Rate Base calculations for 2015.

Table 2.0 - 2015 Rate Base

Rate Base and Working Capital Allowance		
Particulars	**Test Year 2014 (CGAAP)**	
Gross Fixed Assets (average)	$5,071,133	
Accumulated Depreciation (average)	($3,623,655)	
Average Balance		$1,447,478
Allowance for Working Capital		$1,316,443
Total Rate Base		**$2,763,921**
Allowance for Working Capital - Derivation		
Particulars	**Test Year 2014 (CGAAP)**	
Controllable Expenses		$1,087,287
Cost of Power/Power Supply Expense		$9,039,200
Working Capital Base		$10,126,487
Working Capital Rate %		13%
Working Capital Allowance		**$1,316,443**

Ex.2/Tab 1/Sch.2 - Rate Base Trend

Table 2.1 below presents HPDC's Rate Base calculations for all required years including the 2015 Test Year. Year over year variance analysis follows.

Table 2.1 - 2015 Rate Base Trend

Particulars	CGAAP Board Appr 2010	CGAAP Actual 2010	CGAAP Actual 2011	CGAAP Actual 2012	CGAAP Actual 2013	CGAAP Bridge Year 2014	NewCGAAP Test Year 2015
Capital Assets in Service:							
Gross Fixed Assets (average)	3,873,122	3,815,215	3,849,949	3,992,232	4,141,006	4,246,085	5,071,133
Accumulated Depreciation (average)	-3,053,718	-3,002,948	-3,100,687	-3,191,878	-3,274,321	-3,355,433	-3,628,273
Average Balance	819,404	812,267	749,263	800,354	866,686	890,652	1,442,860
Working Capital Allowance	1,173,406	1,061,443	1,178,476	1,263,841	1,425,383	1,334,108	1,316,443
Total Rate Base	**1,992,810**	**1,873,711**	**1,927,738**	**2,064,195**	**2,292,069**	**2,224,760**	**2,759,303**

Table 2.1 - Working Capital Trend

Expenses for Working Capital	CGAAP Board Appr 2010	CGAAP Actual 2010	CGAAP Actual 2011	CGAAP Actual 2012	CGAAP Actual 2013	CGAAP Bridge Year 2014	NewCGAAP Test Year 2015
Eligible Distribution Expenses:							
3500-Distribution Expenses - Operation	95,218	91,992	109,685	123,187	125,808	133,456	143,864
3550-Distribution Expenses - Maintenance	284,565	292,585	308,339	356,254	347,220	382,010	408,504
3650-Billing and Collecting	230,079	230,079	192,856	179,762	202,970	235,636	279,492
3700-Community Relations	5,000	3,479	6,070	673	505	4,500	8,000
3800-Administrative and General Expenses	308,815	250,244	247,846	159,178	177,637	239,292	247,428
Total Eligible Distribution Expenses	923,677	868,380	864,798	819,055	854,139	994,894	1,087,287
3350-Power Supply Expenses	6,899,032	6,207,910	6,991,708	7,606,550	8,648,417	7,899,156	9,039,200
Total Expenses for Working Capital	7,822,709	7,076,290	7,856,506	8,425,605	9,502,556	8,894,050	10,126,487
Working Capital factor	15%	15%	15%	15%	15%	15%	13%
Total Working Capital	**1,173,406**	**1,061,443**	**1,178,476**	**1,263,841**	**1,425,383**	**1,334,108**	**1,316,443**

The Rate Base for 2015 has increased by $534K over 2014 and $766K over the 2010 Board Approved Rate Base. The reason for the sizeable increase in 2015 is mainly attributed to the inclusion of $666K 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 Ex.2/Tab 4/Sch.1.The capital assets added in 2015, exclusive of smart meters, total $165K which includes the replacement of 20 poles, a new pickup truck and billing related computer equipment. Details of these additions

are discussed in length in the Distribution System Plan at Ex.2/Tab 6/Sch.1. 2012 also showed a significant increase due to the replacement of a 26 year old bucket truck. Details on this specific capital expenditure can also be found in the Distribution System Plan. Year over year variance analysis of capital additions are explained at Ex.2/Tab 2/Sch.1.

The Working Capital Allowance has decreased by $17K over 2014 and increased by $144K over the 2010 Board Approved Working Capital Allowance. The reason for the decrease from 2015 to 2014 is due to the change in Working Capital Allowance rate from 15% to 13%. Details on the utility's Working Capital Allowance can be found at Ex.2/Tab 3/Sch.1.

Ex.2/Tab 1/Sch.3 - Rate Base Variance Analysis

The following paragraphs provide a narrative on the changes that have driven the increase in rate base since HPDC's 2010 cost of service.

2015 Test Year vs. 2014 Bridge Year:

Table 2.2 - 2015-2014 Rate Base Variance

Particulars	Bridge 2014	Test Year 2015	Variance $	Variance %
Capital Assets in Service:				
Gross Fixed Assets (average)	4,246,085	5,071,133	825,048	19.43%
Accumulated Depreciation (average)	-3,353,124	-3,628,273	-272,841	8.13 %
Average Balance	890,652	1,442,860	552,208	62.00%
Working Capital Allowance	1,334,108	1,316,443	- 17,664	-1.32%
Total Rate Base	**2,224,069**	**2,759,303**	**534,543**	24.03%

The total projected average balance in 2015 of $1,442,860 million is $552,208 or 62% greater than 2014. The main reason for the variance is the use of an average opening and closing balance for 2014 which saw significant capital additions – more specifically $666K in Smart Meters. Details of Smart Meter Capital Investments are presented at Ex.2/Tab 4/Sch.1.

In 2015, the utility plans on investing in its distribution system in order to keep the system running in a safe and reliable manner. The utility is also planning on replacing 20 deteriorated poles as a result of its asset assessment. Details regarding pole replacements can be found in the Distribution System Plan at Ex.2/Tab 6/Sch.1. This increase in capital investments is offset by the removal of stranded conventional meters from Rate Base and other cost savings. The rest of the increase can be attributed to regular maintenance of the distribution system. The working capital allowance saw a decrease due to the reduction in rate from 15% to 13%.

2014 Bridge Year vs. 2013 Actual:

Table 2.3 - 2014-2013 Rate Base Variance

Particulars	Actual 2013	Bridge Year 2014	Variance $	Variance %
Capital Assets in Service:				
Gross Fixed Assets (average)	4,141,006	4,246,085	105,079	2.54%
Accumulated Depreciation (average)	-3,274,321	-3,353,124	-81,112	2.48%
Average Balance	866,686	890,652	23,966	2.77%
Working Capital Allowance	1,425,383	1,334,108	-91,276	-6.40%
Total Rate Base	**2,292,069**	**2,224,069**	**- 67,309**	-2.94%

The total projected average balance in 2014 of $890,652 is $23,966 or 2.77% greater than 2013. The increase is primarily due to the addition of $151K in capital additions during 2014. Much needed renovations were done to the building and garage. Specifics and justification for this project can be found in the Distribution System Plan at Ex.2/Tab 6/Sch.1. The utility is also investing in office billing equipment such as printers. The rest of the increase can be attributed to regular maintenance of the distribution system. The working capital allowance saw an increase proportional to the increase in OM&A. Details of the OM&A expenditures are presented at Exhibit 4.

2013 Actual vs. 2012 Actual:

Table 2.4 - 2013-2012 Rate Base Variance

Particulars	Actual 2012	Actual 2013	Variance $	Variance %
Capital Assets in Service:				
Gross Fixed Assets (average)	3,992,232	4,141,006	148,775	3.73%
Accumulated Depreciation (average)	-3,191,878	-3,274,321	-82,443	2.58%
Average Balance	800,354	866,686	66,332	8.29%
Working Capital Allowance	1,263,841	1,425,383	161,543	12.78%
Total Rate Base	**2,064,195**	**2,292,069**	**227,874**	11.04%

The total projected average balance in 2013 of $866,686 is $66,332 or 13% greater than 2012. The increase is primarily due to regular maintenance of the distribution system. The working capital allowance saw an increase proportional to the increase in OM&A. Details of the OM&A expenditures are presented at Exhibit 4.

2012 Actual vs. 2011 Actual:

Table 2.5 - 2012-2011 Rate Base Variance

Particulars	Actual 2011	Actual 2012	Variance $	Variance %
Capital Assets in Service:				
Gross Fixed Assets (average)	3,849,949	3,992,232	142,283	3.70%
Accumulated Depreciation (average)	-3,100,687	-3,191,878	-91,191	2.94%
Average Balance	749,263	800,354	51,092	6.82%
Working Capital Allowance	1,178,476	1,263,841	85,365	7.24%
Total Rate Base	**1,927,738**	**2,064,195**	**136,456**	7.08%

The total projected average balance in 2012 of $800,354 is $51,092 or 6.82% greater than 2011. The increase is primarily due to $264,290 in capital additions during 2014. The utility purchased a bucket truck to replace a unit that was purchased in 1986 and was at end of life. Details can be found in the Distribution System Plan at Ex.2/Tab 6/Sch.1. The rest of the increase can be attributed to regular maintenance of the distribution system. The working capital allowance saw an increase proportional to the increase in OM&A. Details of the OM&A expenditures are presented at Exhibit 4.

2011Actual vs. 2010 Actual:

Table 2.6 - 2011-2010 Board Approved Rate Base Variance

Particulars	Actual 2010	Actual 2011	Variance $	Variance %
Capital Assets in Service:				
Gross Fixed Assets (average)	3,815,215	3,849,949	34,734	0.91%
Accumulated Depreciation (average)	-3,002,948	-100,687	-97,739	3.25%
Average Balance	812,267	749,263	-63,005	-7.76%
Working Capital Allowance	1,061,443	1,178,476	117,032	11.03%
Total Rate Base	**1,873,711**	**1,927,738**	**54,028**	2.88%

2011 shows a marginal decrease in average net fixed assets and is more reflective of a typical year with additions related to typical maintenance of the distribution system. The working capital allowance mirrors the increase in OM&A as detailed at Exhibit 4

2010 Actual vs. 2010 Board-Approved:

Table 2.7 – 2010 Actual - 2010 Board Approved Rate Base Variance

Particulars	Board Appr 2010	Actual 2010	Variance $	Variance %
Capital Assets in Service:				
Gross Fixed Assets (average)	3,873,122	3,815,215	-57,907	-1.50%
Accumulated Depreciation (average)	-3,053,718	- 3,002,948	50,771	-1.66%
Average Balance	819,404	812,267	-7,137	-0.87%
Working Capital Allowance	1,173,406	1,061,443	-111,963	-9.54%
Total Rate Base	**1,992,810**	**1,873,711**	**-119,099**	-5.98%

Lastly, 2010 Actuals vs Board Approved also shows a slight decrease in average net fixed assets. The total average balance in 2010 Actual of $812,267 is $7,137 lesser or -0.87% lesser than the 2010 Board Approved. The underspending can be attributed to the fact that rates were not approved until mid-year. HPDC, like many others, tend to put capital investments on hold until the cost of service application is approved. This caused delays in HPDC investing time in maintaining and upgrading its system.

Gross Assets

Ex.2/Tab 2/Sch.1 - Gross Assets Variance Analysis

Tables 2.8 through 2.11 show Gross Asset variances by RRFE functions; System Access, System Renewal, System Services and General Plan. The utility is also presenting a Breakdown of the utility's Gross Assets by function (distribution plant, general plant etc.) at Table 2.12 which follows this section.

Table 2.8 – System Access Variances

Reporting Basis	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS
Projects	2010	2011	2012	2013	2014	2015
System Access						
Misc. construction/expansion anticipated in area	$0	$0	$0	$0	$33,000	$11,000
Contributed Capital					-$33,000	-11,000
Sub-Total System Access - Contributed Capital						
Sub-Total System Access	**0**	**0**	**0**	**0**	**0**	**0**

2010 - 2015

System access investments are modifications or relocation a distributor is obligated to perform to provide a customer. Taking in consideration the lack of growth and development in the service area, there are no material projects initiated in this category. There are no projects initiated by other authorities, nor by system expansion requirements nor by Renewable Energy Generation.

Specifics can be found in the Distribution System Plan at Ex.2/Tab 6/Sch.1

Table 2.9 - System Renewal Variances

System Renewal	2010	2011	2012	2013	2014	2015
1830/1835 - Distribution Overhead - Replace Poles	$4,782	$7,571	$22,120	$9,735	$0	$0
1830 - Distribution Overhead - Replace Poles	$0	$0	$0	$0	$12,464	$0
1835 - Distribution Overhead - Overhead Conduits	$0	$0	$0	$0	$13,750	$0
1830 - Distribution Overhead - Replace Poles	$0	$0	$0	$0	$0	$70,000
1835 - Distribution Overhead - Overhead Conduits	$0	$0	$0	$0	$0	$5,000
1845 - U/G conductors and devices - Install new base	$2,690	$484	$1,196	$10,036	$10,161	$5,431
1850 - Line Transformers - Replace transformer	$10,782	$5,806	$0	$0	$11,120	$6,017
Sub-Total System Renewal - Contributed Capital						
Sub-Total System Renewal	**18,254**	**13,861**	**23,316**	**19,771**	**47,495**	**86,448**

2010 - 2015

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services. The System Renewal expenditures for 2011 is stable and reflect normal yearly maintenance. In 2012 HPDC invested slightly more in Pole Replacement expenditure. The rest of the System Renewal expenditures once again reflect normal yearly maintenance. Overall expenditures in 2013 reflect normal yearly maintenance. In 2014 expenditures also reflect normal yearly maintenance with a slightly higher than normal investment in Pole Replacement expenditure and overhead conduits.

In 2015 HPDC plans on investing considerably more in Pole Replacement expenditure and overhead conduits. This investment supports the new Pole Replacement Program which is described in the Distribution System Plan which is found at Ex.2/Tab 6/Sch.1.

Table 2.10 - System Service Variances

System Service	2010	2011	2012	2013	2014	2015
1860 - Meters - New meters	$0	$5,338	$0	$0	$0	$0
1855 - Services	$0	$0	$142	$0	$0	$0
1860 - Meters - New PT, CT transformers for meters	$0	$0	$197	$0	$0	$0
1860 - Meters - New meters	$0	$0	$0	$7,258	$0	$0
1860 - Meters - New meters	$0	$0	$0	$0	$0	$0
1860 - Meters - New meters	$0	$0	$0	$0	$0	$2,625
1835 - Overhead Conductors & Devices - Replace porcelain surge arrestors	$0	$0	$0	$0	$0	$13,000
1835 - Overhead Conductors & Devices - New solid blade switch	$0	$0	$0	$0	$0	$3,000
Contributed Capital						
Sub-Total System Service - Contributed Capital						
Sub-Total System Service	**0**	**5,338**	**339**	**7,258**	**0**	**18,625**

2010 - 2015

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. The historical years show little investment in System services other than new meters in 2011 and 2013 and replacement of porcelain surge arrestors planned for 2015.

Specifics can be found in the Distribution System Plan at Ex.2/Tab 6/Sch.1

Table 2.11 General Plant Variances

General Plant	2010	2011	2012	2013	2014	2015
1908 - Building & Fixtures - New overhead door	$0	$0	$13,597	$0	$0	$0
1908 - Building & Fixtures - New sidewalk and pavement	$0	$0	$4,294	$0	$0	$0
1908 - Building & Fixtures - New exterior siding, insulation, windows & doors	$0	$0	$0	$0	$70,000	$0
1908 - Building & Fixtures - New natural gas furnace + Building sign	$0	$0	$0	$0	$0	$7,500
1915 - Office Furniture Equipment -	$5,236	$0	$0	$0	$0	$0
1915 - Office Furniture Equipment - New desktops	$0	$0	$0	$3,732	$0	$0
1915 - Office Furniture Equipment - New desk & cabinets for new employee	$0	$0	$0	$0	$2,500	$0
1915 - Office Furniture Equipment - New phone system	$0	$0	$0	$0	$0	$2,500
1920 - Computer Equipment Hardware	$0	$0	$0	$0	$0	$0
1920 - Computer Equipment Hardware - New server and laptop	$0	$0	$0	$0	$11,250	$0
1920 - Computer Equipment Hardware - New desktop at warehouse (3,000$) + New laser printer for billing (7,000$)	$0	$0	$0	$0	$0	$10,000
1925 - Computer Software - Billing software update	$0	$0	$5,795	$0	$0	$0
1925 - Computer Software - Billing software upgrade	$0	$0	$0	$0	$11,500	$0
1925 - Computer Software - GIS software, billing software upgrades	$0	$0	$0	$0	$0	$5,000
1930 - Transportation - New boom insert installed on bucket truck T95-1	$0	$25,129	$0	$0	$0	$0
1930 - Transportation - New Bucket & Boom truck	$0	$0	$218,139	$0	$0	$0
1930 - Transportation - New pickup	$0	$0	$0	$28,201	$0	$0
1930 - Transportation -	$0	$0	$0	$0	$0	$0
1930 - Transportation - New pickup	$0	$0	$0	$0	$0	$28,000
1940 - Tools & Equipment - Pressure washer	$0	$0	$0	$0	$0	$0
1940 - Tools & Equipment - New tools	$0	$1,651	$0	$0	$0	$0
1940 - Tools & Equipment - Hydraulic Press, new tools	$0	$0	$0	$0	$8,450	$0
1940 - Tools & Equipment - New Locator	$0	$0	$0	$0	$0	$7,000
Contributed Capital						
Sub-Total General Plant - Contributed Capital						
Sub-Total General Plant	**5,236**	**26,780**	**241,825**	**31,933**	**103,700**	**60,000**

Total Capital Expenditures	**23,490**	**45,979**	**265,480**	**58,962**	**151,195**	**165,073**

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

2010 –2011

While the percentage increase in 2011 was not particularly notable, the increased dollar value reflects a new boom insert installed on bucket truck T95-1. The truck itself was actually purchased in 2012.

2011 - 2012

The 2012 General Plant expenditures increased significantly due to the purchase of a bucket truck to replace a 26 year old truck that had reached the end of its useful life. Further details can be found in the Distribution System Plan.

2012 – 2013

The 2013 General Plant expenditures reflect the purchase of new pickup truck to replace a truck purchased in 1999. This unit was rusted and in need of considerable maintenance. Further details can be found in the Distribution System Plan.

2013 – 2014

The 2014 General Plant expenditures focused more on much needed building renovations. As indicated in the Distribution System Plan, the aluminum siding and the doors and windows were replaced and 1.5 inches of ISO type Styrofoam board was installed all around. The doors and windows in particular allowed cold air leaks to occur. These improvements, taken together, should result in significantly lower heating costs this winter.

2014 – 2015

The General Plant expenditures for the test year reflect investments in a second pickup truck and computer hardware, more specifically a new desktop at the warehouse and a new laser printer for billing.

Table 2.12 - Breakdown by functions (distribution plant, general plant etc.)

			2010	2010	2010	2011	2011	2012	2012	2012	2013	2013	2014	2014	2015	2015
Function	OEB	Description	Opening Balance	Additions	Closing Balance	Additions	Closing Balance	Additions	Disposals	Closing Balance	Additions	Closing & Opening Balance	Additions	Closing Balance	Additions	Closing Balance
Intangible assets	1611	Computer Software (Formally known as Account 1925)	$115,957		$115,957		$115,957	$5,795		$121,752		$121,752	$11,500	$133,252	$5,000	$138,252
Intangible assets	1612	Land Rights (Formally known as Account 1906)	$4,232		$4,232		$4,232			$4,232		$4,232		$4,232		$4,232
Total			**$120,189**	**$0**	**$120,189**	**$0**	**$120,189**	**$5,795**	**$0**	**$125,984**	**$0**	**$125,984**	**$11,500**	**$137,484**	**$5,000**	**$142,484**
Distribution Plan	1805	Land	$0		$0		$0			$0		$0		$0		$0
Distribution Plan	1808	Buildings			$0		$0			$0		$0		$0		$0
Distribution Plan	1810	Leasehold Improvements			$0		$0			$0		$0		$0		$0
Distribution Plan	1815	Transformer Station Equipment >50 kV			$0		$0			$0		$0		$0		$0
Distribution Plan	1820	Distribution Station Equipment <50 kV			$0		$0			$0		$0		$0		$0
Distribution Plan					$0		$0			$0				$0		$0
Distribution Plan	1825	Storage Battery Equipment	$666,633	$2,203	$668,836	$5,045	$673,881	$13,038		$686,919		$0	$12,464	$702,510	$70,000	$772,510
Distribution Plan	1830	Poles, Towers & Fixtures	$947,944	$2,579	$950,523	$2,525	$953,048	$9,083		$962,131	$3,127	$690,046	$13,750	$982,489	$21,000	$1,003,489
Distribution Plan	1835	Overhead Conductors & Devices	$5,873	$1,881	$7,754	$484	$8,238		-$1,190	$7,048	$6,608	$968,739		$7,681		$7,681
Distribution Plan	1840	Underground Conduit	$423,391	$809	$424,200		$424,200	$1,196		$425,396	$633	$7,681	$10,161	$444,960	$5,431	$450,391
Distribution Plan	1845	Underground Conductors & Devices	$544,950	$10,201	$555,151	$2,766	$557,917		$0	$557,917	$9,403	$434,799	$11,120	$569,037	$6,017	$575,054
Distribution Plan	1850	Line Transformers	$9,766	$581	$10,347	$3,040	$13,387	$142		$13,529		$557,917		$13,529		$13,529
Distribution Plan	1855	Services (Overhead & Underground)	$132,180		$132,180	$5,338	$137,518	$197		$137,715		$13,529		$144,973		$144,973
Distribution Plan	1860	Meters			$0		$0			$0	$7,258	$144,973		$0	$2,625	$669,539
Total			**$2,730,737**	**$18,254**	**$2,748,991**	**$19,198**	**$2,768,189**	**$23,656**	**-$1,190**	**$2,790,655**	**$27,029**	**$2,817,684**	**$47,495**	**$2,865,179**	**$105,073**	**$3,637,166**
General Plan	1860	Meters (Smart Meters)	$7,600		$7,600		$7,600			$7,600		$0		$7,600		$7,600
General Plan	1905	Land	$214,579		$214,579		$214,579	$17,890		$232,469		$7,600	$70,000	$302,469	$7,500	$309,969
General Plan	1908	Buildings & Fixtures			$0		$0			$0		$232,469		$0		$0
General Plan	1910	Leasehold Improvements	$42,114		$42,114		$42,114			$42,114		$0	$2,500	$44,614	$2,500	$47,114
General Plan	1915	Office Furniture & Equipment (10 years)			$0		$0			$0		$42,114		$0		$0
General Plan	1915	Office Furniture & Equipment (5 years)	$77,302	$0	$77,302		$77,302			$77,302		$0		$77,302		$77,302
General Plan	1920	Computer Equipment - Hardware	$2,220		$2,220		$2,220			$2,220		$77,302		$2,220		$2,220
General Plan	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$20,122	$5,236	$25,358		$25,358			$25,358		$2,220	$11,250	$40,340	$10,000	$50,340
General Plan	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$486,435	$0	$486,435	$25,129	$511,564	$218,140	-$25,704	$704,000	$3,732	$29,090	$0	$732,201	$28,000	$760,201
General Plan	1930	Transportation Equipment	$1,855		$1,855		$1,855			$1,855	$28,201	$732,201		$1,855		$1,855
General Plan	1935	Stores Equipment	$96,771		$96,771	$1,651	$98,422			$98,422		$1,855	$8,450	$106,872	$7,000	$113,872
General Plan	1940	Tools, Shop & Garage Equipment			$0		$0			$0		$98,422		$0		$0
General Plan	1945	Measurement & Testing Equipment			$0		$0			$0		$0		$0		$0
General Plan	1950	Power Operated Equipment	$3,546		$3,546		$3,546			$3,546		$0		$3,546		$3,546
General Plan	1955	Communications Equipment			$0		$0			$0		$3,546		$0		$0
General Plan	1955	Communication Equipment (Smart Meters)			$0		$0			$0		$0		$0		$0
General Plan	1960	Miscellaneous Equipment			$0		$0			$0		$0		$0		$0
General Plan	1970	Load Management Controls Customer Premises			$0		$0			$0		$0		$0		$0
General Plan	1975	Load Management Controls Utility Premises			$0		$0			$0		$0		$0		$0
General Plan	1980	System Supervisor Equipment			$0		$0			$0		$0		$0		$0
General Plan	1985	Miscellaneous Fixed Assets			$0		$0			$0		$0		$0		$0
General Plan	1990	Other Tangible Property			$0		$0			$0		$0		$0		$0
General Plan	1995	Contributions & Grants										$0		$0		$0
Total			**$952,544**	**$5,236**	**$957,780**	**$26,780**	**$984,560**	**$236,030**	**-$25,704**	**$1,194,886**	**$31,933**	**$1,226,819**	**$92,200**	**$1,319,019**	**$55,000**	**$1,374,019**
Other liabilities and deffered credits	2440	Deferred Revenue[5]			$0		$0			$0				$0		$0
Total																
		Total	**$3,803,470**	**$23,490**	**$3,826,960**	**$45,978**	**$3,872,938**	**$265,481**	**-$26,894**	**$4,111,525**	**$58,962**	**$4,170,487**	**$151,195**	**$4,321,682**	**$165,073**	**$5,153,669**

Ex.2/Tab 2/Sch.2 - Accumulated Depreciation

HPDC has adopted depreciation rates based on the Kinectrics which can be found on the Ontario Energy Board website or using the following link;

http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf.

The rates used are presented below. The Continuity Schedules of the Accumulated Depreciation are presented at the next pages.

While HPDC's accumulated depreciation generally increases at the same pace as the utility capital investment, the accumulated depreciation for 2015 is somewhat skewed because of the increased depreciable service lives as well as the additions of smart meter related capital.

HPDC's depreciation expense policy and methodology are provided at Ex.2/Tab 5/Sch.3. The depreciation expenses continuity schedules are presented at Ex.4/Tab 4/Sch.1.

Table 2.13 below provides HPDC's depreciable lives by asset class.

Table 2.13 – Comparison of Depreciation Rates

Account	Description	CGAAP	Modified CGAAP Post 2013
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

Ex.2/Tab 2/Sch.3 - Fixed Asset Continuities

This Schedule presents a continuity schedule of its investment in capital assets, the associated accumulated amortization and the net book value for each Capital USoA account for the 2010 Historic Year, 2011 Historic Year, 2012 Historic Year, 2013 Bridge Year and 2015 Test Year.

HPDC attests that the continuity statements reconcile with the calculated depreciation expenses, under Exhibit 4 – Operating Costs, and presented by asset account.

The only Asset Retirement Obligations occurred in 2012. The retirements are; a 1986 bucket truck at a value of -$25,704 and an underground conduit at a value of $1,190. The two asset retirements are reflected in the fixed assets continuity statements at the next page.

Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year 2010

CCA Class	OEB	Description	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)	$ 115,957			$ 115,957	-$ 79,372	-$ 12,195		-$ 91,567	$ 24,390
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,232			$ 4,232	-$ 3,512	-$ 180		-$ 3,692	$ 540
N/A	1805	Land	$ -			$ -				$ -	$ -
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV				$ -				$ -	$ -
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 666,633	$ 2,203		$ 668,836	-$ 510,491	-$ 16,032		-$ 526,523	$ 142,313
47	1835	Overhead Conductors & Devices	$ 947,944	$ 2,579		$ 950,523	-$ 715,017	-$ 22,456		-$ 737,473	$ 213,050
47	1840	Underground Conduit	$ 5,873	$ 1,881		$ 7,754	-$ 1,147	-$ 294		-$ 1,441	$ 6,313
47	1845	Underground Conductors & Devices	$ 423,391	$ 809		$ 424,200	-$ 352,402	-$ 14,121		-$ 366,523	$ 57,677
47	1850	Line Transformers	$ 544,950	$ 10,201		$ 555,151	-$ 457,900	-$ 8,540		-$ 466,440	$ 88,711
47	1855	Services (Overhead & Underground)	$ 9,766	$ 581		$ 10,347	-$ 1,857	-$ 414		-$ 2,271	$ 8,076
47	1860	Meters	$ 132,180			$ 132,180	-$ 79,557	-$ 3,593		-$ 83,150	$ 49,030
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land	$ 7,600			$ 7,600				$ -	$ 7,600
47	1908	Buildings & Fixtures	$ 214,579			$ 214,579	-$ 78,998	-$ 4,022		-$ 83,020	$ 131,559
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 42,114			$ 42,114	-$ 32,903	-$ 2,873		-$ 35,776	$ 6,338
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 77,302	$ -		$ 77,302	-$ 77,302			-$ 77,302	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,220			$ 2,220	-$ 1,985	-$ 235		-$ 2,220	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 20,122	$ 5,236		$ 25,358	-$ 5,663	-$ 3,952		-$ 9,615	$ 15,743
10	1930	Transportation Equipment	$ 486,435	$ -		$ 486,435	-$ 465,421	-$ 9,060		-$ 474,481	$ 11,954
8	1935	Stores Equipment	$ 1,855			$ 1,855	-$ 1,855			-$ 1,855	$ -
8	1940	Tools, Shop & Garage Equipment	$ 96,771			$ 96,771	-$ 85,841	-$ 1,582		-$ 87,423	$ 9,348
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 3,546			$ 3,546	-$ 1,773	-$ 355		-$ 2,128	$ 1,418
8	1955	Communication Equipment (Smart				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]									
						$ -				$ -	$ -
		Sub-Total	**$ 3,803,470**	**$ 23,490**	**$ -**	**$ 3,826,960**	**-$ 2,952,996**	**-$ 99,904**	**$ -**	**-$ 3,052,900**	**$ 774,060**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 3,803,470**	**$ 23,490**	**$ -**	**$ 3,826,960**	**-$ 2,952,996**	**-$ 99,904**	**$ -**	**-$ 3,052,900**	**$ 774,060**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 99,904**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ -
Stores Equipment	$ -
Net Depreciation	-$ 99,904

1

Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year 2011

CCA Class	OEB	Description	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)	$ 115,957			$ 115,957	-$ 91,567	-$ 12,195		-$ 103,762	$ 12,195
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,232			$ 4,232	-$ 3,692	-$ 180		-$ 3,872	$ 360
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 668,836	$ 5,045		$ 673,881	-$ 526,523	-$ 15,479		-$ 542,002	$ 131,879
47	1835	Overhead Conductors & Devices	$ 950,523	$ 2,525		$ 953,048	-$ 737,473	-$ 21,680		-$ 759,153	$ 193,895
47	1840	Underground Conduit	$ 7,754	$ 484		$ 8,238	-$ 1,441	-$ 304		-$ 1,745	$ 6,493
47	1845	Underground Conductors & Devices	$ 424,200			$ 424,200	-$ 366,523	-$ 8,112		-$ 374,635	$ 49,565
47	1850	Line Transformers	$ 555,151	$ 2,766		$ 557,917	-$ 466,440	-$ 8,630		-$ 475,070	$ 82,847
47	1855	Services (Overhead & Underground)	$ 10,347	$ 3,040		$ 13,387	-$ 2,271	-$ 475		-$ 2,746	$ 10,641
47	1860	Meters	$ 132,180	$ 5,338		$ 137,518	-$ 83,150	-$ 3,554		-$ 86,704	$ 50,814
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 7,600			$ 7,600	$ -			$ -	$ 7,600
47	1908	Buildings & Fixtures	$ 214,579			$ 214,579	-$ 83,020	-$ 4,023		-$ 87,043	$ 127,536
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 42,114			$ 42,114	-$ 35,776	-$ 2,873		-$ 38,649	$ 3,465
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 77,302			$ 77,302	-$ 77,302	$ -		-$ 77,302	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,220			$ 2,220	-$ 2,220	$ -		-$ 2,220	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 25,358			$ 25,358	-$ 9,615	-$ 4,476		-$ 14,091	$ 11,267
10	1930	Transportation Equipment	$ 486,435	$ 25,129		$ 511,564	-$ 474,481	-$ 11,573		-$ 486,054	$ 25,510
8	1935	Stores Equipment	$ 1,855			$ 1,855	-$ 1,855			-$ 1,855	$ -
8	1940	Tools, Shop & Garage Equipment	$ 96,771	$ 1,651		$ 98,422	-$ 87,423	-$ 1,665		-$ 89,088	$ 9,334
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 3,546			$ 3,546	-$ 2,128	-$ 355		-$ 2,483	$ 1,063
8	1955	Communication Equipment (Smart	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	$ -				$ -				
			$ -			$ -				$ -	$ -
		Sub-Total	**$ 3,826,960**	**$ 45,978**	**$ -**	**$ 3,872,938**	**-$ 3,052,900**	**-$ 95,574**	**$ -**	**-$ 3,148,474**	**$ 724,465**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 3,826,960**	**$ 45,978**	**$ -**	**$ 3,872,938**	**-$ 3,052,900**	**-$ 95,574**	**$ -**	**-$ 3,148,474**	**$ 724,465**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 95,574**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ -
Stores Equipment	$ -
Net Depreciation	-$ 95,574

Fixed Asset Continuity Schedule

Accounting Standard CGAAP Old CGAAP
Year 2012

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 115,957	$ 5,795		$ 121,752	-$ 103,762	-$ 13,353		-$ 117,115	$ 4,637
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,232			$ 4,232	-$ 3,872	-$ 180		-$ 4,052	$ 180
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 673,881	$ 13,038		$ 686,919	-$ 542,002	-$ 15,109		-$ 557,111	$ 129,808
47	1835	Overhead Conductors & Devices	$ 953,048	$ 9,083		$ 962,131	-$ 759,153	-$ 21,163		-$ 780,316	$ 181,815
47	1840	Underground Conduit	$ 8,238		-$ 1,190	$ 7,048	-$ 1,745	-$ 280		-$ 2,025	$ 5,023
47	1845	Underground Conductors & Devices	$ 424,200	$ 1,196		$ 425,396	-$ 374,635	-$ 7,209		-$ 381,844	$ 43,552
47	1850	Line Transformers	$ 557,917		$ -	$ 557,917	-$ 475,070	-$ 9,462		-$ 484,532	$ 73,385
47	1855	Services (Overhead & Underground)	$ 13,387	$ 142		$ 13,529	-$ 2,746	-$ 538		-$ 3,284	$ 10,245
47	1860	Meters	$ 137,518	$ 197		$ 137,715	-$ 86,704	-$ 3,413		-$ 90,117	$ 47,598
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 7,600			$ 7,600	$ -			$ -	$ 7,600
47	1908	Buildings & Fixtures	$ 214,579	$ 17,890		$ 232,469	-$ 87,043	-$ 4,201		-$ 91,244	$ 141,225
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 42,114			$ 42,114	-$ 38,649	-$ 1,578		-$ 40,227	$ 1,887
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 77,302			$ 77,302	-$ 77,302			-$ 77,302	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,220			$ 2,220	-$ 2,220			-$ 2,220	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 25,358			$ 25,358	-$ 14,091	-$ 4,476		-$ 18,567	$ 6,791
10	1930	Transportation Equipment	$ 511,564	$ 218,140	-$ 25,704	$ 704,000	-$ 486,054	-$ 29,734	$ 25,704	-$ 490,084	$ 213,916
8	1935	Stores Equipment	$ 1,855			$ 1,855	-$ 1,855			-$ 1,855	$ -
8	1940	Tools, Shop & Garage Equipment	$ 98,422			$ 98,422	-$ 89,088	-$ 1,461		-$ 90,549	$ 7,873
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 3,546			$ 3,546	-$ 2,483	-$ 355		-$ 2,838	$ 708
8	1955	Communication Equipment (Smart	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 3,872,938**	**$ 265,481**	**-$ 26,894**	**$ 4,111,525**	**-$ 3,148,474**	**-$ 112,512**	**$ 25,704**	**-$ 3,235,282**	**$ 876,244**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 3,872,938**	**$ 265,481**	**-$ 26,894**	**$ 4,111,525**	**-$ 3,148,474**	**-$ 112,512**	**$ 25,704**	**-$ 3,235,282**	**$ 876,244**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 112,512**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	$ -
Stores Equipment	$ -
Net Depreciation	-$ 112,512

Fixed Asset Continuity Schedule

Accounting Standard: CGAAP (Old CGAAP)
Year: 2013

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 121,752			$ 121,752	-$ 117,115	-$ 1,159		-$ 118,274	$ 3,478
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,232			$ 4,232	-$ 4,052	-$ 180		-$ 4,232	$ -
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 686,919	$ 3,127		$ 690,046	-$ 557,111	-$ 14,682		-$ 571,793	$ 118,253
47	1835	Overhead Conductors & Devices	$ 962,131	$ 6,608		$ 968,739	-$ 780,316	-$ 20,564		-$ 800,880	$ 167,859
47	1840	Underground Conduit	$ 7,048	$ 633		$ 7,681	-$ 2,025	-$ 294		-$ 2,319	$ 5,362
47	1845	Underground Conductors & Devices	$ 425,396	$ 9,403		$ 434,799	-$ 381,844	-$ 6,415		-$ 388,259	$ 46,540
47	1850	Line Transformers	$ 557,917			$ 557,917	-$ 484,532	-$ 8,801		-$ 493,333	$ 64,584
47	1855	Services (Overhead & Underground)	$ 13,529			$ 13,529	-$ 3,284	-$ 541		-$ 3,825	$ 9,704
47	1860	Meters	$ 137,715	$ 7,258		$ 144,973	-$ 90,117	-$ 3,544		-$ 93,661	$ 51,312
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 7,600			$ 7,600	$ -			$ -	$ 7,600
47	1908	Buildings & Fixtures	$ 232,469			$ 232,469	-$ 91,244	-$ 4,379		-$ 95,623	$ 136,846
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 42,114			$ 42,114	-$ 40,227	-$ 1,168		-$ 41,395	$ 719
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 77,302			$ 77,302	-$ 77,302			-$ 77,302	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,220			$ 2,220	-$ 2,220			-$ 2,220	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 25,358	$ 3,732		$ 29,090	-$ 18,567	-$ 2,017		-$ 20,584	$ 8,506
10	1930	Transportation Equipment	$ 704,000	$ 28,201		$ 732,201	-$ 490,084	-$ 51,474		-$ 541,558	$ 190,643
8	1935	Stores Equipment	$ 1,855			$ 1,855	-$ 1,855			-$ 1,855	$ -
8	1940	Tools, Shop & Garage Equipment	$ 98,422			$ 98,422	-$ 90,549	-$ 1,461		-$ 92,010	$ 6,412
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 3,546			$ 3,546	-$ 2,838	-$ 355		-$ 3,193	$ 353
8	1955	Communication Equipment (Smart	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 4,111,525**	**$ 58,962**	**$ -**	**$ 4,170,487**	**-$ 3,235,282**	**-$ 117,034**	**$ -**	**-$ 3,352,316**	**$ 818,172**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 4,111,525**	**$ 58,962**	**$ -**	**$ 4,170,487**	**-$ 3,235,282**	**-$ 117,034**	**$ -**	**-$ 3,352,316**	**$ 818,172**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 117,034**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 117,034

Fixed Asset Continuity Schedule

Accounting Standard: CGAAP (New CGAAP)
Year: 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 121,752	$ 11,500		$ 133,252	-$ 118,274	-$ 2,309		-$ 120,583	$ 12,669
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,232			$ 4,232	-$ 4,232			-$ 4,232	$ -
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 690,046	$ 12,464		$ 702,510	-$ 560,780	-$ 3,842		-$ 564,622	$ 137,888
47	1835	Overhead Conductors & Devices	$ 968,739	$ 13,750		$ 982,489	-$ 799,051	-$ 18,961		-$ 818,012	$ 164,477
47	1840	Underground Conduit	$ 7,681			$ 7,681	-$ 2,303	-$ 285		-$ 2,588	$ 5,093
47	1845	Underground Conductors & Devices	$ 434,799	$ 10,161		$ 444,960	-$ 383,911	-$ 2,311		-$ 386,222	$ 58,738
47	1850	Line Transformers	$ 557,917	$ 11,120		$ 569,037	-$ 487,047	-$ 2,654		-$ 489,701	$ 79,336
47	1855	Services (Overhead & Underground)	$ 13,529			$ 13,529	-$ 3,823	-$ 539		-$ 4,362	$ 9,167
47	1860	Meters	$ 144,973			$ 144,973	-$ 99,208	-$ 9,333		-$ 108,541	$ 36,432
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 7,600			$ 7,600	$ -			$ -	$ 7,600
47	1908	Buildings & Fixtures	$ 232,469	$ 70,000		$ 302,469	-$ 96,776	-$ 6,032		-$ 102,808	$ 199,661
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 42,114	$ 2,500		$ 44,614	-$ 40,542	-$ 440		-$ 40,982	$ 3,632
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 77,302			$ 77,302	-$ 77,302			-$ 77,302	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,220			$ 2,220	-$ 2,220			-$ 2,220	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 29,090	$ 11,250		$ 40,340	-$ 22,133	-$ 3,765		-$ 25,898	$ 14,442
10	1930	Transportation Equipment	$ 732,201	$ -		$ 732,201	-$ 517,932	-$ 30,668		-$ 548,600	$ 183,601
8	1935	Stores Equipment	$ 1,855			$ 1,855	-$ 1,855			-$ 1,855	$ -
8	1940	Tools, Shop & Garage Equipment	$ 98,422	$ 8,450		$ 106,872	-$ 92,779	-$ 2,653		-$ 95,432	$ 11,440
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 3,546			$ 3,546	-$ 3,192	-$ 354		-$ 3,546	$ -
8	1955	Communication Equipment (Smart	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	$ -				$ -				
						$ -	$ -			$ -	$ -
		Sub-Total	**$ 4,170,487**	**$ 151,195**	**$ -**	**$ 4,321,682**	**-$ 3,313,360**	**-$ 84,146**	**$ -**	**-$ 3,397,506**	**$ 924,177**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 4,170,487**	**$ 151,195**	**$ -**	**$ 4,321,682**	**-$ 3,313,360**	**-$ 84,146**	**$ -**	**-$ 3,397,506**	**$ 924,177**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 84,146**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 84,146

Fixed Asset Continuity Schedule

Accounting Standard: MIFRS
Year: 2015

CCA Class	OEB	Description	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
12	1611	Computer Software (Formally known as Account 1925)	$ 133,252	$ 5,000		$ 138,252	-$ 120,583	-$ 3,959		-$ 124,542	$ 13,710
CEC	1612	Land Rights (Formally known as Account 1906)	$ 4,232			$ 4,232	-$ 4,232			-$ 4,232	$ -
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 702,510	$ 70,000		$ 772,510	-$ 564,622	-$ 4,758		-$ 569,380	$ 203,130
47	1835	Overhead Conductors & Devices	$ 982,489	$ 21,000		$ 1,003,489	-$ 818,012	-$ 19,347		-$ 837,359	$ 166,130
47	1840	Underground Conduit	$ 7,681			$ 7,681	-$ 2,588	-$ 285		-$ 2,873	$ 4,808
47	1845	Underground Conductors & Devices	$ 444,960	$ 5,431		$ 450,391	-$ 386,222	-$ 2,506		-$ 388,728	$ 61,663
47	1850	Line Transformers	$ 569,037	$ 6,017		$ 575,054	-$ 489,701	-$ 2,869		-$ 492,570	$ 82,484
47	1855	Services (Overhead & Underground)	$ 13,529			$ 13,529	-$ 4,362	-$ 539		-$ 4,901	$ 8,628
47	1860	Meters	$ 144,973			$ 144,973	-$ 108,541	-$ 9,333		-$ 117,874	$ 27,099
47	1860	Meters (Smart Meters)	$ 666,914	$ 2,625		$ 669,539	-$ 162,513	-$ 45,475		-$ 207,988	$ 461,551
N/A	1905	Land	$ 7,600			$ 7,600	$ -			$ -	$ 7,600
47	1908	Buildings & Fixtures	$ 302,469	$ 7,500		$ 309,969	-$ 102,808	-$ 6,698		-$ 109,506	$ 200,463
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 44,614	$ 2,500		$ 47,114	-$ 40,982	-$ 690		-$ 41,672	$ 5,442
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 77,302			$ 77,302	-$ 77,302			-$ 77,302	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 2,220			$ 2,220	-$ 2,220			-$ 2,220	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 40,340	$ 10,000		$ 50,340	-$ 25,898	-$ 4,754		-$ 30,652	$ 19,688
10	1930	Transportation Equipment	$ 732,201	$ 28,000		$ 760,201	-$ 548,600	-$ 33,468		-$ 582,068	$ 178,133
8	1935	Stores Equipment	$ 1,855			$ 1,855	-$ 1,855			-$ 1,855	$ -
8	1940	Tools, Shop & Garage Equipment	$ 106,872	$ 7,000		$ 113,872	-$ 95,432	-$ 1,828		-$ 97,260	$ 16,612
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 3,546			$ 3,546	-$ 3,546			-$ 3,546	$ -
8	1955	Communication Equipment (Smart	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 4,988,596**	**$ 165,073**	**$ -**	**$ 5,153,669**	**-$ 3,560,019**	**-$ 136,509**	**$ -**	**-$ 3,696,528**	**$ 1,457,142**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 4,988,596**	**$ 165,073**	**$ -**	**$ 5,153,669**	**-$ 3,560,019**	**-$ 136,509**	**$ -**	**-$ 3,696,528**	**$ 1,457,142**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 136,509**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 136,509

Allowance for Working Capital

Ex.2/Tab 3/Sch.1 - Derivation of Working Capital

HPDC 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, 2013 a rate of 13% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). HPDC attests that the Cost of Power is determined by split between RPP and non-RPP customers based on actual data, use most current RPP price, use current UTR. The derivation of the Cost of Power is detailed at the next pages. Table 2.14 presented below show HPDC's calculations in determining its Allowance for Working Capital.

Table 2.14 - Allowance for Working Capital

	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	NewCGAAP	MIFRS
Expenses for Working Capital	**Board Appr 2010**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Bridge Year 2014**	**Test Year 2015**
Eligible Distribution Expenses:							
3500-Distribution Expenses - Operation	95,218	91,992	109,685	123,187	125,808	133,456	143,864
3550-Distribution Expenses - Maintenance	284,565	292,585	308,339	356,254	347,220	382,010	408,504
3650-Billing and Collecting	230,079	230,079	192,856	179,762	202,970	235,636	279,492
3700-Community Relations	5,000	3,479	6,070	673	505	4,500	8,000
3800-Administrative and General Expenses	308,815	250,244	247,846	159,178	177,637	239,292	247,428
Total Eligible Distribution Expenses	923,677	868,380	864,798	819,055	854,139	994,894	1,087,287
3350-Power Supply Expenses	6,899,032	6,207,910	6,991,708	7,606,550	8,648,417	7,899,156	9,039,200
Total Expenses for Working Capital	7,822,709	7,076,290	7,856,506	8,425,605	9,502,556	8,894,050	10,126,487
Working Capital factor	15%	15%	15%	15%	15%	15%	13%
Total Working Capital	**1,173,406**	**1,061,443**	**1,178,476**	**1,263,841**	**1,425,383**	**1,334,108**	**1,316,443**

Ex.2/Tab 3/Sch.2 - Lead Lag Study

HPCLD is not proposing to use a lead lag study in order to determine its Working Capital Allowance.

Ex.2/Tab 3/Sch.3 – Cost of Power

HPDC is an embedded distributor of Hydro One Networks Inc. ("HONI") and is charged monthly by HONI for its power supply expenses. HPDC is also a market participant with the IESO.

Pass-through charges for power supply include commodity, retail transmission services, wholesale market service, rural rate protection and low voltage service. Debt retirement charges are not included. A total loss factor applies to forecast retail volumes for all pass-through charges other than low voltage service, when the billing determinant is kWh.

Commodity Price

The assumed commodity prices are based on the Regulated Price Plan ("RPP") Report issued by the OEB on October 16, 2014. The estimated price for RPP customers corresponds to the average supply cost for RPP customers specified in the report's Table ES-1 as indicated in the excerpt below.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from November 1, 2014)

RPP Supply Cost Summary
for the period from November 1, 2014 through October 31, 2015

		Current
Forecast Wholesale Electricity Price		$20.64
Load-Weighted Price for RPP Consumers ($ / MWh)		$22.52
Impact of the Global Adjustment ($ / MWh)	+	$74.88
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	($3.45)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$94.96**

HPDC used RPP and non-RPP split to calculate the weighted average commodity price. The table below shows HPDC's determinate of its commodity. HPDC reserves the right to update its commodity price based on updated prices are they become available.

Retail Transmission Service ("RTSR") Rates

Proposed RTSRs for Network Service and Line and Transformation Connection Service are described in Ex.8/Tab 1/Sch.4.

Wholesale Market Service ("WMS") Rate

HPDC proposes to maintain its current WMS rate of $0.0044 per kWh, as prescribed by the OEB. Details of WMS are presented at Ex.8/Tab 1/Sch.6.

Rural Rate Protection

The existing Rural Rate Protection charge of $0.0013 per kWh has been maintained. Details of RRP are presented at Ex.8/Tab 1/Sch.7.

Smart Meter Entity Charge

The existing Smart Meter Entity charge of $0.79 per applicable customer class has been maintained. Details of RRP are presented at Ex.8/Tab 1/Sch.8.

Low Voltage ("LV") Service

HPDC estimates total charges of $55,936 in 2015 for LV service. Proposed retail rates for LV are described in Ex.8/Tab 1/Sch.10

Calculation of Power Supply Expenses (Cost of Power) is presented at the next page.

Table 2.15 – Commodity Calculations

	Last Actual kWh's		
Customer Class Name	**Last Actual kWh's**	**non-RPP**	**RPP**
Residential	25,300,382	506,210	24,794,172
General Service < 50 kW	11,359,856	750,587	10,609,269
General Service > 50 to 1499 kW	23,218,142	20,126,523	3,091,619
Intermediate	21,805,339	21,805,339	0
Sentinel Lighting	21,276	21,276	0
Street Lighting	1,026,377	1,026,377	0
TOTAL	**82,731,372**	**43,209,935**	**39,521,437**
%	*100.00%*	*52.23%*	*47.77%*
Forecast Price			
HOEP ($/MWh)		$22.52	
Global Adjustment ($/MWh)		$74.88	
Adjustments			
TOTAL ($/MWh)		**$97.40**	**$94.96**
$/kWh		***$0.09740***	***$0.09496***
%		52.23%	47.77%
WEIGHTED AVERAGE PRICE	**$0.0962**	**$0.0509**	**$0.0454**

Electricity Projections							
(loss adjusted)							
		Bridge Year 2014			**Test Year 2015**		
Customer							
Class Name		Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	25,681,979	0.0796	$2,044,285	24,997,909	$0.09623	$2,405,659
General Service < 50 kW	kWh	11,531,193	0.0796	$917,883	11,224,046	$0.09623	$1,080,139
General Service > 50 to 1499 kW	kWh	23,568,333	0.0796	$1,876,039	22,940,563	$0.09623	$2,207,671
Intermediate	kWh	21,734,287	0.0796	$1,730,049	21,193,267	$0.09623	$2,039,521
Sentinel Lighting	kWh	19,709	0.0796	$1,569	17,125	$0.09623	$1,648
Street Lighting	kWh	1,131,659	0.0796	$90,080	443,750	$0.09623	$42,704
TOTAL		**83,667,159**		**$6,659,906**	**80,816,661**		**$7,777,342**

Power Supply Expense

Determination of Commodity

		Last Actual kWh's		
Customer Class Name		**Last Actual kWh's**	**non-RPP**	**RPP**
Residential		25,300,382	506,210	24,794,172
General Service < 50 kW		11,359,856	750,587	10,609,269
General Service > 50 to 1499 kW		23,218,142	20,126,523	3,091,619
Intermediate		21,805,339	21,805,339	0
Sentinel Lighting		21,276	21,276	0
Street Lighting		1,026,377	1,026,377	0
TOTAL		**82,731,372**	**43,209,935**	**39,521,437**
%		*100.00%*	*52.23%*	*47.77%*

Forecast Price

HOEP ($/MWh)				$22.52		Note: Table ES-1 from current RPP report - Load Weighted price for RPP Consumers
Global Adjustment ($/MWh)				$74.88		Note: Table ES-1 from current RPP report - Impact of Global Adjustment
Adjustments						
TOTAL ($/MWh)				**$97.40**	**$94.96**	Note: Table ES-1 from current RPP report - Impact of Global Adjustment
$/kWh				***$0.09740***	***$0.09496***	
%				52.23%	47.77%	
WEIGHTED AVERAGE PRICE		**$0.0962**		**$0.0509**	**$0.0454**	

Electricity Projections

(loss adjusted)

				Bridge Year 2014			Test Year 2015		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	4006	4705	25,681,979	0.0796	$2,044,285	24,997,909	$0.09623	$2,405,659
General Service < 50 kW	kWh	4010	4705	11,531,193	0.0796	$917,883	11,224,046	$0.09623	$1,080,139
General Service > 50 to 1499 kW	kWh	4035	4705	23,568,333	0.0796	$1,876,039	22,940,563	$0.09623	$2,207,671
Intermediate	kWh			21,734,287	0.0796	$1,730,049	21,193,267	$0.09623	$2,039,521
Sentinel Lighting	kWh	4010	4705	19,709	0.0796	$1,569	17,125	$0.09623	$1,648
Street Lighting	kWh	4025	4705	1,131,659	0.0796	$90,080	443,750	$0.09623	$42,704
TOTAL				**83,667,159**		**$6,659,906**	**80,816,661**		**$7,777,342**

Transmission - Network

(loss adjusted)

				Bridge Year 2014			Test Year 2015		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4066	4714	25,681,979	0.0061	$156,660	24,997,909	0.0064	$159,987
General Service < 50 kW	kWh	4066	4714	11,531,193	0.0056	$64,575	11,224,046	0.0059	$66,222
General Service > 50 to 1499 kW	kW	4066	4714	64,980	2.3025	$149,617	63,249	2.4291	$153,639
Intermediate	kW	4066	4714	62,109	2.5753	$159,948	60,563	2.7169	$164,542
Sentinel Lighting	kW	4066	4714	58	1.7453	$101	50	1.8413	$92
Street Lighting	kW	4066	4714	11,350	1.7364	$19,708	4,451	1.8319	$8,154
TOTAL				**37,351,668**		**$550,609**	**36,350,268**		**$552,635**

Transmission - Connection

(loss adjusted)

				Bridge Year 2014			Test Year 2015		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4068	4716	25,681,979	0.0048	$123,273	24,997,909	0.0050	$124,990
General Service < 50 kW	kWh	4068	4716	11,531,193	0.0042	$48,431	11,224,046	0.0044	$49,386
General Service > 50 to 1499 kW	kW	4068	4716	64,980	1.7025	$110,629	63,249	1.7847	$112,881
Intermediate	kW	4068	4716	62,109	2.0081	$124,720	60,563	2.1051	$127,490
Sentinel Lighting	kW	4068	4716	58	1.3314	$77	50	1.3957	$69
Street Lighting	kW	4068	4716	11,350	1.3043	$14,804	4,451	1.3673	$6,086
TOTAL		**0**	**0**	**37,351,668**		**$421,934**	**36,350,268**		**$420,902**

Wholesale Market Service

(loss adjusted)

				Bridge Year 2014			Test Year 2015		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**	**0.0052**		**rate ($/kWh):**	**0.0052**
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4708	25,681,979	0.00440	$113,001	24,997,909	0.00440	$109,991
General Service < 50 kW	kWh	4062	4708	11,531,193	0.00440	$50,737	11,224,046	0.00440	$49,386
General Service > 50 to 1499 kW	kW	4062	4708	64,980	0.00440	$286	63,249	0.00440	$278
Intermediate	kW	4062	4708	62,109	0.00440	$273	60,563	0.00440	$266
Sentinel Lighting	kW	4062	4708	58	0.00440	$0	50	0.00440	$0

Street Lighting	kW	4062	4708	11,350	0.00440	$50	4,451	0.00440	$20
TOTAL		**0**	**0**	**37,351,668**		**$164,347**	**36,350,268**		**$159,941**

Rural Rate Protection

(loss adjusted)

				Bridge Year 2014			**Test Year 2015**		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4730	25,681,979	0.00120	$30,818	24,997,909	0.00130	$32,497
General Service < 50 kW	kWh	4062	4730	11,531,193	0.00120	$13,837	11,224,046	0.00130	$13,469
General Service > 50 to 1499 kW	kW	4062	4730	64,980	0.00120	$78	63,249	0.00130	$76
Intermediate	kW	4062	4730	62,109	0.00120	$75	60,563	0.00130	$73
Sentinel Lighting	kW	4062	4730	58	0.00120	$0	50	0.00130	$0
Street Lighting	kW	4062	4730	11,350	0.00120	$14	4,451	0.00130	$5
TOTAL		**0**	**0**	**37,351,668**		**$44,822**	**36,350,268**		**$46,120**

Smart Meter Entity Charge

(per customer)

				Bridge Year 2014			**Test Year 2015**		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	Cust			2,273	0.79000	$1,796	2,273	0.79000	$21,549
General Service < 50 kW	Cust			467	0.79000	$369	467	0.79000	$4,430
General Service > 50 to 1499 kW	Cust								
Intermediate	Cust								
Sentinel Lighting	Cust								
Street Lighting	Cust								
TOTAL		**0**	**0**	**2,740**		**$2,165**	**2,740**		**$25,978**

Low Voltage Charges

	Current Low Voltage Rates		**2015 PROJECTED TRANSMISSION-CONNECTION REVENUE**				
Customer Class Name	**Rate**	**per**	**Rate**	**per**	**Uplifted**	**Revenue**	**%**
Residential	$0.0007	kWh	**$0.0050**	kWh	24,997,909	$124,990	29.70%
General Service < 50 kW	$0.0006	kWh	**$0.0044**	kWh	11,224,046	$49,386	11.73%
General Service > 50 to 1499 kW	$0.2270	kW	**$1.7847**	kW	63,249	$112,881	26.82%
Intermediate	$0.2677	kW	**$2.1051**	kW	60,563	$127,490	30.29%
Sentinel Lighting	$0.1791	kW	**$1.3957**	kW	50	$69	0.02%
Street Lighting	$0.1755	kW	**$1.3673**	kW	4,451	$6,086	1.45%
TOTAL	**0**	**0**		**$0**	**36,350,268**	**$420,902**	**100%**

Low Voltage Charges

(not loss adjusted)

	2015 PROPOSED LOW VOLTAGE CHARGES & RATES					
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted**	**Rate**	**per**
Residential	29.70%	16,610	24,257,123	$0.0007	kWh
General Service < 50 kW	11.73%	6,563	10,891,433	$0.0006	kWh
General Service > 50 to 1499 kW	26.82%	15,001	63,249	$0.2372	kW
Intermediate	30.29%	16,943	60,563	$0.2798	kW
Sentinel Lighting	0.02%	9	50	$0.1855	kW
Street Lighting	1.45%	809	4,451	$0.1817	kW
TOTAL	**100.00%**	**55,936**	**35,276,869**	**0**	

				Bridge Year 2014			**Test Year 2015**		
Customer		**Revenue**	**Expense**		**2014**			**2015**	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	24,920,921	$0.0007	$17,445	24,257,123	$0.0007	$16,979.99
General Service < 50 kW	kWh	4075	4750	11,189,478	$0.0006	$6,714	10,891,433	$0.0006	$6,534.86
General Service > 50 to 1499 kW	kW	4075	4750	64,980	$0.2270	$14,750	63,249	$0.2372	$15,002.72
Intermediate	kW	4075	4750	62,109	$0.2677	$16,626	60,563	$0.2798	$16,945.40
Sentinel Lighting	kW	4075	4750	58	$0.1791	$10	50	$0.1855	$9.23
Street Lighting	kW	4075	4750	11,350	$0.1755	$1,992	4,451	$0.1817	$808.75
TOTAL		**0**	**0**	**36,248,896**		**$57,538**	**35,276,869**		**$56,280.95**

Projected Power Supply Expense						**$7,899,156**			**$9,039,200**

Smart Meter Deployment and Stranded Meters

Ex.2/Tab 4/Sch.1 - Disposition of Smart Meters and Treatment of Stranded Meters

Introduction

HPCDL is 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, 2008 to April 30, 2012. HPCDL requested approval of proposed Smart Meter Disposition Riders ("SMDRs").

As of December 31, 2012, 100% of the Applicant's customer base had conventional meters replaced with smart meters. The total Smart Meter Initiative costs claimed in this application are $914,434 as indicated in Table 2.16 below.

Table 2.16 - Summary of Cost Claim

Total Capital Costs	$663,877
Total OM&A Costs	$250,557

The costs of the Smart Meter Initiative (to December 31, 2012) are partially offset by the SMFA, in the amount of $181,062. This includes accumulated interest.

HPDC is seeking Board approval for a Smart Meter Disposition Rate Rider in the amount of $3.28 per metered residential customer per month; $4.82 per metered GS<50 customer per month; $7.84 per metered GS>50 customer per month and $8.90 per intermediate customer per month. The calculation was made utilizing the Board's Smart Meter Model which is being filed in conjunction with this application. The value of the SMDR is based on the net amount resulting from:

Deferred and forecasted Smart Meter Incremental Revenue Requirement from January 1, 2008 to December 31, 2012

Plus

Interest on Deferred and forecasted OM&A and Amortization Expenses from January 1, 2008 to December 31, 2012

Less

SMFA Revenues collected (including carrying charges) from May 1, 2006 to April 30, 2012

The Applicant is proposing to follow the allocation methodology applied by the Board in the Smart Meter Initiative proceedings of other distributors. The resulting rate riders being proposed are displayed in Table 2.17 below.

Table 2.17 - Summary of Rate Riders and Adders

Revenue Requirement for Historical Years	Residential	GS < 50 kW	GS 50 to 4999 kW	Intermediate
SMFA Revenues plus interest expense	$154,941.90	$26,009.91	$2,584.42	$49.11
Net Deferred Revenue Requirement to be recovered via SMDR	$358,302.11	$107,937.58	$15,055.00	$854.56
Average number of customers (2015), for applicable classes	2273	467	40	2
Number of Years for SMDR recovery	4	4	4	4
Smart Meter Disposition Rider ($/month per metered customer in the customer class)	$3.28	$4.82	$7.84	$8.90

According to the Board's Guideline, the Smart Meter Disposition Rider ("SMDR") recovers, over a specified time period, the variance between: 1) the deferred revenue requirement for the Smart Meter Initiative up to the time of disposition, and 2) the SMFA revenues collected from May 2006 through April 2012 and associated carrying charges until May 1, 2014.

The Applicant's costs of the Smart Meter Initiative were calculated to be $237.52 for capital cost per meter and $327 for total cost per meter as set out in Table 2.18 below.

Table 2.18 - Summary of Cost Claim

Total Smart Meter Capital Costs	$663,876.95
Total Smart Meter OM&A Costs	$250,556.73
Total Smart Meter Costs	$914,433.68
Total Number of Smart Meters installed or planned to be installed	2795
Capital Cost per customer	$237.52
OM&A Cost per customer	$89.64
Total Cost per customer	$327.17

No costs associated with stranded meters have been included in the above calculations. Stranded meters are disposed of in accordance with the Board's Guideline, section 3.7 which states, "The Board therefore expects that stranded meter costs will be left in rate base until the distributor's next cost of service application."

Moreover, the Applicant is not seeking recovery at this time for any costs that exceed minimum functionality required by the Province of Ontario. The Board's Guideline, section 3.4, described beyond minimum functionality as incremental smart meter technical capabilities, deployment to larger customers and Time-of-Use ("TOU") implementation costs such as CIS system upgrades, w presentation, integration with the Province's MDM/R, etc.

Procurement and installation

HPDC together with 7 other District 9 Distribution Utilities collaborated together to reduce their Smart Meter costs and hired Util-Assist to prepare a Smart Meter budget and to assist District 9 utilities through the smart meter process. Util-Assist has a standard contracting fee for their services that was shared equally among the 7 utilities. This process enabled the distributors located in Northern Ontario, including HPDC, to benefit from collective expertise and buying power.

HPDC purchased the smart meter infrastructure and contracted with "Sensus" for the maintenance of the communication towers and the Regional Network Interface ("RNI") in 2009. Installations of smart meters were done completely by HPDC employees.

Installation

HPCDL's full-scale smart meter deployment commenced in August 2009. The installation activity is detailed in Table 2.19 below.

Table 2.19 - Smart Meter Installations by Year and by Rate Class

	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
	2008	2009	2010	2011	2012	2013	2014	2015	
Smart Meter Installation Plan									
Residential	82	2,221							2303
General Service < 50 kW		412	11	10	17				450
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)	82	2633	11	10	17	0	0	0	2753
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	2.98%	98.62%	99.02%	99.38%	100.00%	0.00%	100.00%	0.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed		36	1	2	1				40
Other (please identify) Intermediate				1	1				2
Total Number of Smart Meters installed or planned to be installed	82	2669	12	13	19	0	0	0	2795

HPCDL installed a total of 2795 smart meters as at December 31, 2012, which represented 100% of its Residential and 100% of the GS < 50 rate classes.

Audited balances

In 2010, HPCDL an audit letter from its accountants stating that the accounting firm proposed to transfer audited balances. The letter is appended to the end of this schedule. The letter listed capital costs at 437,190 and depreciation costs at $14,427. Below is a reconciliation of the numbers from the auditor's letter and the proposed balances sought for recovery in this application.

A. Smart meter Capital = 437,190$
B. Smart meter OM&A = 55,044.97$
C. Stranded Meters = 45,081$
D. Smart Meter Amort = 14,427$
E. Smart Meter Acc. Amort = -14,427$
F. Smart Meter Funding Revenues = -43,159.27$
G. Smart Meter Carrying Charges = 1,218$

To balance as per 2009 Audited Fin. Statement. = A + B + C + F + G = 495,374$

HPCDL installed a total of 2795 smart meters as at December 31, 2012, which represented 100% of its Residential and 100% of the GS < 50 rate classes.

Treatment of Stranded Meters

In the minimum filing requirements , The Board's states that the Smart Meter Funding and Cost Recovery (G-2008-0002) provides two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters:

- (Scenario A) If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555;.or
- (Scenario B) If the stranded meter costs remained recorded in Account 1860.

HPDC attests that its utility falls under Scenario B as the stranded meters have, until now, resided in Account 1860 - Meters.

The table below (excerpt from Appendix 2-R of the Board's Appendices) shows the net book value of HPDC's stranded smart meters.

The total cost of the stranded meters that HPCDL is claiming in this current application is $51,087. The table below show stranded meters disposed of prior to 2009 and stranded meters disposed after 2010 to 2013.

Table 2.20 - Stranded Meter Treatment

TABLE # - FOR RESIDENTIAL AND G<50 METERS DISPOSED ON OR BEFORE 2009

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		$ 226,442	$ 167,255		$ 59,187		$ 59,187
2007		$ 226,442	$ 172,898		$ 53,544		$ 53,544
2008		$ 226,442	$ 178,540		$ 47,902		$ 47,902
2009		$ 226,442	$ 181,361		$ 45,081		$ 45,081
2010		$ 45,081			$ 45,081		$ 45,081
2011		$ 45,081			$ 45,081		$ 45,081
2012		$ 45,081			$ 45,081		$ 45,081
2013		$ 45,081			$ 45,081		$ 45,081
2014		$ 45,081			$ 45,081		$ 45,081

TABLE # - FOR G>50 & INTERMEDIATE METERS DISPOSED FROM 2010 TO 2013

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		$ 96,809	$ 71,505		$ 25,304		$ 25,304
2007		$ 96,809	$ 73,918		$ 22,891		$ 22,891
2008		$ 96,809	$ 76,330		$ 20,479		$ 20,479
2009		$ 96,809	$ 78,742		$ 18,067		$ 18,067
2010		$ 96,809	$ 81,154		$ 15,655		$ 15,655
2011		$ 96,809	$ 83,566		$ 13,243		$ 13,243
2012		$ 96,809	$ 85,978		$ 10,831		$ 10,831
2013		$ 96,809	$ 88,391		$ 8,418		$ 8,418
2014		$ 96,809	$ 90,803		$ 6,006		$ 6,006

Appendix 2-S requests that utilities complete the following information relating to the treatment of the utility's stranded meters.

1. A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

Thus far, stranded meters were included in account 1860 and therefore were treated accordance with CGAAP with the same accounting rules as standard meters.

2. The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2012.

The amount of pooled residual net book value as of December 31st, 2013 is in the amount of $51,087

3. A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2013.

Smart meters were fully installed by the end of 2012. The 2012 depreciation expense was for $14,106 for meters disposed of before 2009 and 19298 for meters disposed of from 2010 to 2013.

4. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2012.

N/A Please see question #3 above.

5. The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

The estimated net amount at end of 2013 was $51,087

6. A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

The applicant intends to recover the cost of the Stranded Meters through a Rate Rider. The proposed recovery period is 4 years. Calculations of the proposed rate rider are presented at Table 2.21 below. Please note that the utility used the 2009 CA model as an allocation % (EB-2009-0266_Hearst_2010 CA Model DRO_20110331).

Table 2.21 - Smart Meter Rate Rider

Customer Class Name	Net Book Value	Direct Allocation	% share	Annual $	Customer	Rate	per month
Residential	$25,901.11		50.70%	6475.28	2273	$2.85	$0.24
General Service < 50 kW	$13,849.69		27.11%	3462.42	467	$7.41	$0.62
General Service > 50 to 4999 kW	$4,480.33		8.77%	1120.08	40	$28.08	$2.34
Intermediate	$6,850.77		13.41%	1712.69	2	$937.09	$78.09
	TOTAL						

Total for Recovery				**51,087**
Recovery Period (years)			**4**	
Annual Recovery				**12,772**

Collins Barrow
Gagné Gagnon Bisson Hébert
Chartered Accountants / Comptables Agréés

Société Professionnelle Denis Hébert Inc.
Eric G. Gagnon Professional Corporation
Christiane S. Lapointe C.A.
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hearst@collinsbarrow.com

February 25, 2010

Hearst Power Distribution Company Ltd.
P.O. Bag 5000
HEARST, Ontario POL 1NO

ATTENTION: Mrs. Nicole Leduc, Manager

Dear Mrs Leduc,

RE: Hearst Power Distribution Company Limited

We are the auditors of the Hearst Power Distribution Company Limited and in our capacity as auditors have reported as of February 19, 2010 on the Hearst Power Distribution Company Limited financial statements for the year ended December 31, 2009.

Purpose

In response to your request, we understand that you need a confirmation of our work regarding the Smart Meters Variance accounts. We also understand that you need a special report identifying the changes to the financial statements after the ensuing issuance of the Ontario Energy Board (OEB) order approving the smart meters deferral account transfer to operating assets for the purpose of the OEB regulation as part of the rate base.

The changes made following the Board approval only reflect the smart meters capital asset portion.

Generally Accepted Accounting Principles and Auditing Standards

The Hearst Power Distribution Company Limited financial statements for the year ended December 31, 2009 have been prepared in accordance with Canadian generally accepted accounting principles.

The audit of the Hearst Power Distribution Company Limited financial statements for the year ended December 31, 2009 has been conducted in accordance with Canadian generally accepted auditing standards.

. . . 2

Audit Procedures for smart meters capital and expenses

The following other substantive procedures were performed, to allow us to conclude that the balances presented in the smart meters variance accounts were fairly stated.

- We vouched all expenses greater than 5 % of our materiality to an invoice and assured that it was related to the smart meters. A total of 94.8 % of all smart meters capital and OM&A expenses were verified;

- We recalculated the stranded cost calculated by Energy Cost Management Inc., as provided by Hearst Power Distribution Company Limited and concluded that it was properly recorded;

- We calculated the amortization expense for the current year and agreed to amount reported;

- We recalculated a sample of the carrying charges and concluded that they were properly calculated and reported.

Per our work performed, we concluded that the amounts presented as smart meters variance accounts were fairly stated, in all material respects as at December 31, 2009.

Accounting procedures for the special report

The following changes were made to reflect the capital portion approval of the smart meters investment.

- We transferred the smart meters capital expenses in the amount of $ 437,190 into the property and equipment account.
- We transferred the accumulated amortization in the amount of $ 14,427 into the accumulated amortization account from the smart meters capital and recovery account.
- We transferred the carrying charges on the smart meters capital and recovery account in the amount of $ 2,324 against the carrying charges interest revenue.

All of the reclassifications made to the smart meters capital and recovery account created changes to the audited financial statements which are presented in the attached special report. We also considered the effects of those reclassifications on the income tax return as of December 31, 2009.

Yours very truly,

COLLINS BARROW

Noël Cantin, CA
NC/ajc

Capital Expenditures

Ex.2/Tab 5/Sch.1 - Planning

The utility's Capital Planning Process is explained in detail at section 4.2. Capital Planning Process Overview of the Distribution System Plan at Ex.2/Tab 6/Sch.1.

Ex.2/Tab 5/Sch.2 - Capitalization Policy

The utility's Capital Policies under the former accounting standards CGAAP and the new IFRS is presented at the next page.

Capitalization Policy under CGAAP

Hearst Power records fixed assets at cost with depreciation taken at various rates in accordance with the Accounting Procedures Handbook and Uniform System of Accounts (USofA). Contributions in aid of construction are not included in the rate base, as they are recorded as an offset to the capital asset and amortized (as an offset to depreciation) at the same rate as the capital assets, thereby providing net depreciation amount for assets.

Hearst Power constructed assets are capitalized at actual labour rates plus a burden for payroll, engineering, vehicle usage (where applicable) and stores.

Hearst Power capitalizes expenditures that are of a capital nature, over $1,000 and that are expected to provide future benefits for a period in excess of one year.

Expenditures incurred to improve or replace an existing asset are capitalized if the asset's useful life is extended or the asset's productivity is increased or the associated operating costs are lowered.

Where a group of like assets are acquired that are individually valued below $1,000, but meet the capitalization criteria above and are in total cost in excess of $1,000, they are capitalized.

Approval of Capital Spending

The Board of Directors annually reviews and approves a capital budget. Individual capital purchases are then reviewed and approved according to financial authorizations policy.

Amortization/Depreciation

Amortization of property and equipment is provided on a straight line basis over the following periods:

• Buildings and fixtures	50 years
• Overhead lines and feeders	25 years
• Underground lines and feeders	25 years
• Transformers	25 years
• Meters	25 years
• Smart Meters	15 years
• Office equipment	10 years
• Automotive equipment	5 years
• Computer equipment	5 years

- Other equipment 10 years

End of Economic Life of an Asset

An asset will be considered to be at the end of its economic life when it is of no further use or potential use to Hearst Power.

Disposal of Capital Assets

Gains and losses on assets sold to non-affiliates are recorded in miscellaneous income.

When property and equipment are disposed of, the proceeds of disposition are recorded as a reduction to the appropriate property and equipment accounts. Gains and losses on disposals are brought into income over the depreciable life of the remaining property and equipment.

Capitalization Policy under IFRS

The Cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating the manner intended by management. All costs shall be documented, recorded historically, including methods and sources used to establish any estimated costs.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)
d) Administration and other general overhead costs; and
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

Directly attributable

The term “directly attributable” is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

General Policy for Capitalization and Depreciation

Hearst Power Distribution capital assets, and their designated service life, should be categorized as follow:

USoA Account Number	USoA Account Description	Service life
1830	Poles, Towers & Fixtures	45
1835	OH Conductor and devices	45
1850	Line Transformers	40
1845	UG conductor and devices	25
1840	UG Conduit and Foundations	50
1860	Meters	15
1860	Smart meters	15
1905	Land	N/A
1908	**Building**	
1908	Building - Structure	70
1908	Building Outside / Fence	30
1908	Interior	20
1908	Roof	25
1915	Office Furniture / Equipment	10
1920	Computer Equipment	5
1930	**Vehicles**	
1930	Boom Truck and Heavy trucks	10
1930	Trailers	10
1930	Pick up	5
1935	Store Equipment	10
1940	Tools, Shop and Garage equipment	10
1955	Communication Equipment	10

In addition to the direct cost, Hearst Power Distribution applies the labour and vehicle burdens for these direct costs. These burden costs are described further below. The minimum threshold for capitalizing is 1,000$ for all capital project or expense. It is implied that a number of expenditures can be grouped together under a specified capital project in order to reach the minimum threshold and be recorded as capital asset.

Account 1830 to 1860 – Poles, OH Conductors, Transformers, UG Conduit, Meters, etc.

The capitalized expenditures for these accounts include:

- Material and supplies direct costs
- Labour direct cost
- Labour burden
- Vehicle and equipment burden

Material and supplies direct costs

The material and supplies direct cost is comprised of all the eligible material that is used on a capital project, including its freight to destination. No storage, stockroom expenses or administrative charges are added.

Labour Direct Cost

The labour direct cost consists of all the eligible salaries for staff as well of their supervisors on a capital project.

Labour Burden

The Labour Burden is comprised of employee benefits including:

- Employment Insurance Premiums (Employer portion)
- Canada Pension Plan Premiums (Employer portion)
- Employer Health Tax Premiums
- OMERS (Employer portion)
- Medical and Health Benefits
- Life Insurance
- WSIB
- Clothing and Safety Footwear Allocation
- Vacations
- Statutory Holidays
- Bereavement
- On-call / stand-by costs

The Labour Burden rate is a percentage calculated every year and based on the actual employee rates and benefits costs divided by 2,080 hrs (regular hours worked in a year). Then all employee rates are added together and divided by the number of employee to get the average overhead percentage hourly rate for the year. The Labour Burden rate is then allocated to capital based upon the Labour Direct Cost charged to capital.

In 2014, the labor burden percentage rate was established at 49.10%.

Vehicle and Equipment Burden

A vehicle burden rate is calculated for each class of vehicle based on the budgeted costs of operating each vehicle and the budgeted hours of usage for each class. The hourly rate is based on the total expenses, divided by the number of hours used. This hourly rate is allocated to capital based on the time that the vehicle is used on the job-site, thus establishing the fact that the use of the vehicle is directly attributable to an item of PP&E. The expenses below are included in the operating costs:

- Depreciation
- Vehicle Maintenance
- Fuel
- Insurance

Account 1905 - Land Acquisition

The recorded cost of land includes:

- The purchase price;
- Costs of closing the transaction and obtaining title, which includes but are not limited to legal fees, survey costs and land transfer taxes
- The cost for preparing the land for its particular use such as clearing and grading. If the land is purchased for the purpose of constructing a building, all costs incurred up to the excavation for the new building should be considered land costs. Removal of an old building, clearing, grading and filling are considered land costs because they are necessary to get the land in condition for its intended purpose. Any proceeds obtained in the process of getting the land ready for its intended use, such as salvage receipts on the demolition of the old building or the sale of cleared timber, are treated as reductions in the price of the land.

Expenditures for land acquisition usually do not deteriorate with use or passage of time, therefore the cost of land is generally not exhaustible, and therefore not depreciable.

Account 1908 – Building

Capitalization of Building costs include, but are not limited to, the following:

- Original contract price of asset;
- Expenses for remodeling, repairing or changing a purchased building to make it available for the purpose for which it was acquired;

- Interest charges until building acquisition, renovation project, improvement or alteration is complete;
- Architects and engineers fees for design as well as expenses for the preparation of plans, specifications, blueprints, etc.;
- Cost of building permits.

Each building is divided into 4 major building components. The components are as follows:

1. Building Structure
2. Building Outside / Fence
3. Interior Construction
4. Roof

The total cost of the building or additional square footage is then allocated among the 4 major building components.

Building Renovations/Rehabilitation

A building renovation is defined as enhancements made to a previously existing building component. The total expenditure capitalized is based on the invoice or contract price. No administrative charges are added.

Building Outside / Fence improvements

Building Outside / Fence improvements include items such as landscaping, driveways, sidewalks, parking lots, fencing, outdoor lighting, and other non-building improvements. Please note that Land improvements can be further categorized as non-exhaustible under account 1905 – Land acquisitions. The total project cost must meet the set minimum threshold and shall be recorded as capital based on the invoice or contract price. No administrative charges are added.

Account 1915 to 1955 – Office Furniture, Computer, Vehicles, Tools and Other Equipment

For capitalization of expenditures with a service life of more than one year, the total invoice or contract price is used, including its freight to destination. No storage, stockroom expenses or administrative charges are added.

Ex.2/Tab 5/Sch.4 - Capitalization of Overhead

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 therefore HPDC has not populate nor is filing Appendix 2-D as part of this application.

Ex.2/Tab 5/Sch.5 - Costs of Eligible Investments for Distributors

HPDC attests that it has not included any costs or included any Investments to Connect Qualifying Generation Facilities in its capital costs nor in its Distribution System Plan and as such has not populated nor is filling Appendices 2-FA through 2-FC.

Ex.2/Tab 5/Sch.6 - New Policy Options for the Funding of Capital

HPCDL is not proposing any special or different approach of funding its capital expenditure

Ex.2/Tab 5/Sch.7 - Addition of ICM Assets to Rate Base

HPCDL has never applied for a rate adder to recover an investment through the OEB's Incremental Capital Module.

Distribution System Plan

Ex.2/Tab 6/Sch.1 - Stand Alone Distribution System Plan

The Distribution System Plan is presented at the next page.

Hearst Power Distribution Company Limited

Distribution System Plan

December 11, 2014.

Submitted by: J. Richard

INDEX

Table of Contents

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1. (5.2) Distribution System Plan

This Distribution System Plan follows the chapter and section headings set out in Chapter 5. Although the section numbering in this Distribution System Plan does not match the Chapter 5 reference numbers, the Chapter 5 reference numbers are included in each of the heading titles in brackets. The report follows the headings in the sequence required in Chapter 5. The information in this report was provided by Hearst Power Distribution Company Limited (HPDC) and the report was prepared by AESI for HPDC.

1.1. Utility Overview

HPDC is the local distribution company that is responsible for the distribution of electricity to the Town of Hearst. The distribution service territory has an area of 98.67 square kilometers.

HPDC is incorporated under the Ontario Business Corporations Act and is 100% owned by the Town of Hearst. HPDC is managed by a Board of Directors appointed by the Town of Hearst. HPDLC has 7 employees; a General Manager and two billing clerks in the office , a Lead Hand, two linemen and a utility person to address the outside plant matters. The current General Manager was hired in May 2014 to fill the vacancy created by the previous General Manager leaving HPDC after about three years of service. The Manager prior to the previous General Manager served HPDC for about 40 years. The experience and backgrounds of the General Managers has been office and billing or accounting. Consequently the majority of the operational and technical input comes from the Lead hand.

HPDC receives power from Hydro One Networks Inc. (“Hydro One”) and the IESO. HPDC delivers power to its customers via three feeders from a high voltage transformer station, which is owned by Hydro One. Revenue is earned by HPDC by delivering electric power to the homes and businesses in the service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the Ontario Energy Board.

This Distribution System Plan (DSP) documents HPDC’s Asset Management Plan and the Capital Expenditure Plan. The DSP covers the period from 2010 to 2019. The current date for all the information provided is October 2014, except where noted otherwise. This report reflects the costs incurred and the practices in place as of this date. The financial data incorporates the financial results of HPDC for the year ended December 31, 2013. The 2014 Financial information is based on the actual to October and a forecast expenditure for November and December 2014.

HPDC has translated all the capital expenditures to the investment categories as required in the Chapter 5 section 5.2.1 filing requirements.

For the purposes of this Distribution System Plan, 2010 to 2013 are the previous 4 years, 2014 is the current year, 2015 is the Test Year and 2016 to 2019 are the forecast years.

A summary of the type and number of assets, as well as the age distribution, is provided. The maintenance cost per year is provided as required.

The process HPDC uses to assess the condition of its assets and the follow-up is also documented in this report.

The Capital Expenditure Forecast for the 2015 to 2019 time period and the Historical Capital Budget and Actual Expenditure information for the 2010 to 2014 time period is found in section 4.4 [5.5.4] Table 13.

The materiality threshold for detailed reporting of projects is $50,000.

HPDC gathers relevant information about the assets and uses the judgment and experience of its staff to interpret this information to develop appropriate cost effective programs that deliver reliable service to its customers at a reasonable cost.

1.2.[5.2.2] Investments Related to Renewable Energy Generation (REG)

HPDC has had costs related to the connection of REG projects. The connection of the 10MW solar installation required the installation of one pole and a three phase switch in order to allow the facility to connect to the power grid. This amount is shown in the past years capital program and is identified there. No further investments are anticipated to be made by HPDC, since the Hydro One transformer station that any new load would connect to is transmission constrained and not capable of accepting any additional REG load.

2. [5.3] Distribution System Plan

2.1.1. [5.3.1] Distribution System Plan Overview

Located in Northeastern Ontario, the Town of Hearst has a population of approximately 5,600 people, of which 85% are francophone.

Hearst is home to three major forestry productions that are significant contributors to the local economy; two of these are located within HPDC's service area. This last decade, the forestry industry was challenged with cost pressures and turmoil in the US housing market (an important consumer of the region's forestry products), which adversely affected employment in that sector, thereby resulting in a decrease in population and a shortage of skilled workers. The Town of Hearst is focused on attracting industry workers and their families to its community.

The principal economic driver of the local economy is the forest industry but the Town of Hearst also provides business activities and employment opportunities in sectors such as fishing & hunting, tourism, educational services, health care, manufacturing, transportation & warehousing, construction, bio-economy, etc…

The Town of Hearst is considered the centre for post-secondary education in Northeastern Ontario. The Université de Hearst and Collège Boréal provides a wide range of general programs, and are distinguished for their astonishing success rates.

Located near the James Bay lowlands and the “Ring of Fire” (one of the largest potential mineral reserves in Ontario), the Town of Hearst anticipates that someday, this project will create job opportunities and generate growth and long-term prosperity for the community.

HPDC expects the status quo for the business conditions over the planning horizon of this report; no growth and no shrinkage. There are no known expansion plans for industrial, commercial or residential segments of the economy nor are there any known planned closures in the industrial or commercial segments of the economy. The primary business in the area is the production of forest products. This involves timber cutting, hauling, processing, and shipping to market as well as reforestation. The lack of change in the economy means that there is no growth based capital work proposed by HPDC.

Much of overhead plant is old (more than 40 years in service) and an assessment of the condition of the wood poles was carried out. This resulted in the pole replacement program which will replace 126 deteriorated poles over a 5 year period. This is the only “material” project that is proposed to be undertaken.

HPDC is implementing a process to identify and execute approved programs. These have been lacking under the previous General Manager. In this period budgets were approved but the work was not completed nor was the money spent. This makes it necessary to establish these management processes. The new General Manager has started this process since May 2014 when he joined HPDC.

Two capital initiatives in the forecast period provide some potential for cost savings by preventing some outages that occur on the present system and thus saving the power restoration and repair costs that often happen after normal working hours. The project with the most potential in this regard is the lightning arrestor replacement program. When a lightning arrestor fails it typically causes a power interruption. It needs to be removed from the power system and be replaced and also typically other equipment in the immediate vicinity may be damaged because of the arcing that has taken place. This equipment will also need to be repaired or replaced in some cases. Lightning arrestor failures often fail outside of normal working hours which causes the replacement parts to be installed and the power restoration to take place at premium wage rates. When these problem prone lightning arrestors are replaced the costs associated with these failures are expected to be reduced to zero.

Pole failures have not been a frequent occurrence so the savings are expected to be very low but this program will prevent the increase of these costs which will begin to occur if the poles are not replaced now.

The DSP reports 2010 to 2013 as the historical period, 2014 as the current year, 2015 as the test year and 2016 to 2019 as the forecast period.

The data in the DSP is current as of the end of October 2014 unless indicated otherwise in a specific section of the report.

HPDC has not made significant changes in the Asset Management Process. They initiated a more formalized wood pole assessment process as indicated in Appendix E. They are also populating system asset data into a GIS. The GIS is owned and used by a local forest products company who use it to manage their forest management requirements. HPDC has an arrangement to use the system to record its' physical electrical plant. This population of data is being done in 2014. Further GIS capability will be investigated in 2015. Initially only pole and transformer data are being entered.

Since a regional planning study has not been started there are no projects that were initiated by such a study.

2.1.2. [5.3.2] Coordinated Planning With Third Parties

HPDC coordinates with the capital programs undertaken by the Town of Hearst. HPDC monitors the plans of the Town, the scope of work and the impact on existing plant as well as the timing proposed by the Town for their programs. HPDC responds in a timely manner when the projects are committed by the Town.

HPDC monitors the plans of the MTO that it is aware of and responds to any requirements and obligations it has with respect to its plant on Provincial Public Rights of Way.

HPDC coordinates with the OPA and Hydro One. There are no new requirements requested by HPDC since their load has decreased from about 18 MW to about 13 MW over the past 5 years as the result of one of the three forest product plants closing. There is one 10 MW REG solar plant that has been installed and is now connected.

HPDC does not have a SCADA system or other smart grid capability at this time. They do not expect to install such devices or capability in the foreseeable future. They are considering using additional fuses and switching points to be able to prevent larger power interruption events and to restore power to customers more quickly using sectionalizing capability.

There are no new studies that HPDC has been part of and thus there are no deliverables and plans to be incorporated.

In accordance with the filing requirements a report outlining HPDC's REG plan was sent to the OPA. The response to this report can be found in Appendix A. In summary, OPA concurs with the plan and report submitted by HPDC.

2.1.3. [5.3.3] Performance Measurement for Continuous Improvement

HPDC pays attention to the customer oriented performance. Being a small utility and living in the community means that customer concerns are communicated quite easily just by interaction. Four years ago a customer survey was initiated but the number of customer responses was very low. HPDC has completed a residential survey in the summer of 2014. The results of the survey are included in this rate filing at Exhibit 1, Tab 2, Schedule 2. Power rates are frequently commented on.

HPDC monitors the reliability performance of its system. While no one wants to have power interruptions, the customers have not raised any special concerns in this area of performance.

Power quality is not and has not been an issue raised by the public in the HPDC service area.

The 2014 Residential Customer survey had the following results:

The overall performance in serving customers is rated High (97% good or excellent) as is the overall reliability of electrical services (95% good or excellent).

The cost of electricity compared to other services is rated as High (87% good or excellent). The customers also reported that strain on the customer's budget is high (78% with high or some strain).

There is support for renewable energy generation in concept but 84% are not prepared to support extra costs for this while 13% are prepared to pay up to a 5% premium.

HPDC is a respected company in the community as indicated by 99% of the respondents.

In summary, the respondents are happy with the service they receive and the system reliability. They perceive the cost of power as a good deal when compared to other services but the cost of power does impact their budget. Only about 3% of the respondents do not support the concept of renewable energy generation but of the remaining 97%, 84% are not prepared to pay any premium amount for this energy and about 13% are prepared to pay up to a 5% premium. HPDC is highly respected in the community.

These results demonstrate that HPDC is paying attention to customer oriented performance and is meeting the customer's expected performance very well.

Outage Performance

The outage incidents that have occurred on the HPDC system are detailed in Appendix B.

The summary information for the power system reliability is presented in the tables below.

		Year				
Category	**Category Description**	**2010**	**2011**	**2012**	**2013**	**2014 YTD**
0	Unknown	0.00	0.00	0.00	0.00	9.75
1	Scheduled	13.00	0.00	0.00	0.00	593.5
2	Loss of Supply	14937.00	7220.50	626.00	10169.50	1259.75
3	Trees		1.00	28.50		57
4	Lightning		0.00	0.00	4.00	13
5	Defective Equipment	1697.00	721.50	716.25	3153.75	1103.75
6	Adverse Weather		0.00	836.00	300.00	0
7	Adverse Environment		2.00	0.00		0
8	Human Element		0.00	0.00		0
9	Foreign Interference	42.00	29.50	6207.00	26.75	32.75
	Totals- All interruptions	16689.00	7974.50	8413.75	13654.00	3069.5
	Total excluding "loss of supply"	1752.00	754.00	7787.75	3484.50	1809.75

Table 1: Customer - Hours by Cause

		Year				
Category	**Category Description**	**2010**	**2011**	**2012**	**2013**	**2014 YTD**
0	Unknown	0	0	0	0	4
1	Scheduled	4	0	0	0	9
2	Loss of Supply	3	1	4	3	5
3	Trees		1	1		2
4	Lightning		0	0	1	1
5	Defective Equipment	10	10	7	7	7
6	Adverse Weather		0	1	1	0
7	Adverse Environment		1	0		0
8	Human Element		0	0		0
9	Foreign Interference	3	3	4	3	6
	Totals- All interruptions	20	16	17	15	34
	Totals –excluding " loss of supply"	17	15	13	12	29

Table 2: System Interruptions by Cause

		Year				
Category	**Category Description**	**2010**	**2011**	**2012**	**2013**	**2014 YTD**
0	Unknown	0	0	0	0	5
1	Scheduled	42	0	0	0	177
2	Loss of Supply	6455	2063	369	3320	5998
3	Trees		1	19		38
4	Lightning		0	0	2	13
5	Defective Equipment	2008	537	464	2102	566
6	Adverse Weather		0	304	300	0
7	Adverse Environment		2	0		0
8	Human Element		0	0		0
9	Foreign Interference	42	41	2086	25	17
	Totals- All interruptions	8547	2644	3242	5749	6814
	Totals -not loss of supply	2092	581	2873	2429	816

Table 3: Customer Interruptions by Cause

	Customers By Year				
Year	2010	2011	2012	2013	2014 YTD
Customers	2755	2771	2786	2788	2777

Table 4: Customers by Year

Cause & Description	2010	2011	2012	2013	2014 YTD
0-Unknown					1.95
1-Scheduled	0.31				3.35
2-Loss of Supply	2.31	3.50	1.70	3.06	0.21
3-Trees		1.00	1.50		1.50
4-Lightning				2.00	1.00
5-Defective Equipment	0.85	1.34	1.54	1.50	2.00
6-Adverse Weather				1.00	
7-Adverse Environment		1.00			
8-Human Element					
9-Foreign Interference	1.00	0.72	2.98	1.07	1.93
Annual –All Interruptions	1.95	3.02	2.60	2.38	0.45
Annual -excluding "loss of supply"	0.84	1.30	2.71	1.43	2.22

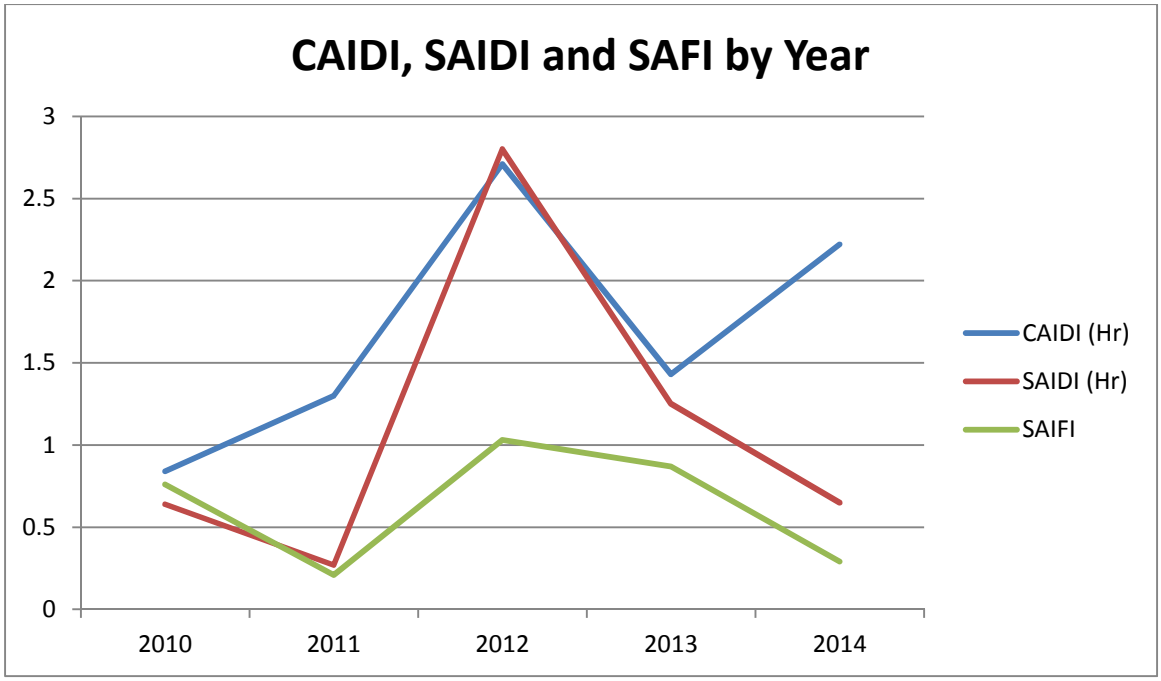
Table 5: CAIDI by Year

Cause & Description	2010	2011	2012	2013	2014 YTD
0-Unknown	0.00	0.00	0.00	0.00	0.00
1-Scheduled	0.00	0.00	0.00	0.00	0.21
2-Loss of Supply	5.42	2.61	0.22	3.65	0.45
3-Trees	0.00	0.00	0.01	0.00	0.02
4-Lightning	0.00	0.00	0.00	0.00	0.00
5-Defective Equipment	0.62	0.26	0.26	1.13	0.40
6-Adverse Weather	0.00	0.00	0.30	0.11	0.00
7-Adverse Environment	0.00	0.00	0.00	0.00	0.00
8-Human Element	0.00	0.00	0.00	0.00	0.00
9-Foreign Interference	0.02	0.01	2.23	0.01	0.01
Annual -All	6.06	2.88	3.02	4.90	1.11
Annual-excluding "loss of supply"	0.64	0.27	2.80	1.25	0.65

Table 6: SAIDI by Year

Cause & Description	2010	2011	2012	2013	2014 YTD
0-Unknown	0.00	0.00	0.00	0.00	0.00
1-Scheduled	0.02	0.00	0.00	0.00	0.06
2-Loss of Supply	2.34	0.74	0.13	1.19	2.16
3-Trees	0.00	0.00	0.01	0.00	0.01
4-Lightning	0.00	0.00	0.00	0.00	0.00
5-Defective Equipment	0.73	0.19	0.17	0.75	0.20
6-Adverse Weather	0.00	0.00	0.11	0.11	0.00
7-Adverse Environment	0.00	0.00	0.00	0.00	0.00
8-Human Element	0.00	0.00	0.00	0.00	0.00
9-Foreign Interference	0.02	0.01	0.75	0.01	0.01
Annual -All	3.10	0.95	1.16	2.06	2.45
Annual - Excluding "loss of supply"	0.76	0.21	1.03	0.87	0.29

Table 7: SAIFI by Year



Graph 8: Reliability Indices by Year Excluding Loss of Supply Outages

The graph above shows that the CAIDI performance, after removing the loss of supply incidents, deteriorates in 2012 and recovers in 2013. 2014 also shows deterioration but this information is based on only 10 months of history.

The 2012 experience is caused by two separate incidents on the same day that are weather related. In a heavy thunderstorm a customer's radio tower appears to have been hit by lightning and one of the guy wires supporting the tower was damaged to the point it contacted the HPDC feeder and locked out the supply breaker at Hearst TS. The crew was called out and they located the problem and cleared the fault. This took three hours to complete. In addition the storm locked out another feeder about 15 minutes after the first feeder lockout and because the crew was responding to the first call they were not able to address the second feeder until later. HPDC has only one line crew. These two related but separate events when taken together account for 82% of the customers interrupted for the year and 90% of the customer hours of interruption –excluding the Loss of Supply incidents. If this incident were excluded CAIDI would have been 1.51 hours which is in line with the previous performance.

The 2013 figures include an incident where a defective lightning arrestor causes a feeder lockout. At the time of the event there was no communication between Hearst TS and the Hydro One control center so remote operation of any part of the TS was not possible. Hence rather than attempt to do partial restoration of the feeder which could cause a larger outage HPDC decided to replace the defective lightning arrestor. This took 1.5 hours to complete. Hydro One sent a travelling operator from Timmins and this added an additional 3 hours to the interruption duration which was categorized as a Loss of Supply outage.

The major contributing event contributing to the higher CAIDI value in 2014 to date is a lightning arrestor failure. This caused a 2.5 hour interruption for 424 customers. Later in August there was a scheduled replacement of a padmounted transformer base which caused a power interruption of 3.5 hours to 157 customers. Some of the HPDC underground system is a radial feed and consequently in this case the infrequent incident of a larger, longer duration interruption occurred. If this becomes a more frequent occurrence HPDC will look into ways to shorten the interruptions such as converting the radial feed into a loop feed. Because the cost of doing this work, HPDC is not proceeding with this until more experience is generated to justify the expenditure. These two events account for 71% of the customers interrupted and 82% of the customer hours interrupted after the exclusion of Loss of Supply outages.

HPDC's 5 year average SAIDI is 1.12 and its' 5 year average SAIFI is .63 not including Loss of Supply interruptions. HPDC works to maintain these levels.

The outage performance analysis for this report has caused HPDC to review its operating and system design practices. In the past HPDC has concentrated on locating the point of system failure and making repairs to restore power. HPDC is considering a move to concentrate on the restoration of power to as many customers as possible through system switching before commencing any repair activities. By doing this HPDC expects to restore a significant number of customers to full power sooner thereby improving its CAIDI and SAIDI performance. To do this HPDC will review its system's ability to restore customers through switching and add additional switches at strategic points to make this achievable. In addition HPDC is reviewing all lines that are not part of the main feeder or a backup with a view to fusing these sections to prevent them from being able to lock out the feeder and thus minimizing the number of customers affected due to faults in these parts of the system.

These steps will reduce the customer hours of outage the system experiences and thus improve the customer experience.

Another observation is that lightning arrestors are failing. These are older design porcelain lightning arrestors and these have a history of failing in various utilities in the province. While the number of failures has been modest, a few per year causing outages, they are associated with major power interruptions. In addition to the negative impact on the reliability performance of the power system, they also present a potential safety hazard to the public because of the explosive manner in which they often fail and the resulting high speed sharp porcelain debris that emanates from the failed device. HPDC plans to replace lightning arrestors over a two year period starting in 2015 and beginning with the locations where there is the largest possibility of public exposure such as schools and urban areas. The installation of Switches, lightning arrestors and fuses will be System Service capital.

HPDC has initiated a more detailed inspection of their older pole assets in 2014. [See Appendix E for the details of this inspection.] This is to assess the condition of these assets that are more than 35 years old. HPDC did this to be able to properly plan the replacement of its at risk assets but in a planned, affordable cost effective manner and gradual impact on the customer's cost of power.

These steps are expected to result in a modest improvement system outage performance to maintain the 5 year average performance as well as an improved safety of the power system for the public and enhance the customer experience while incurring modest capital cost. By the replacement of the porcelain lightning arrestors in the urban areas first, the risk of injury to the public is reduced as much as possible as quickly as possible recognizing that failures are infrequent at present but could cause injury. Further the result is a planned and a cost effective method of addressing the issues discovered by the Distribution System Planning process from both the management of the assets and the capital expenditure planning process perspectives.

HPDC identifies its' capital requirements using the categories indicated by the regulator.

The System access requirements are driven by others such as customers and other authorities. At present these requirements are very low and none of the projects come close to approaching the materiality threshold on an annual basis even when all the projects are summed for the year. Further, the projects initiated by customers are all typically completely funded by customer contributions.

The System Renewal requirements are very modest and do not approach the materiality threshold except for the pole replacement program. HPDC surveyed the condition of poles more than 30 years in service in 2014 and identified 128 poles to be replaced. These will be replaced at a rate of 20 per year moving forward. The details of the survey and the results are listed in Appendix E. Project justification for this project can be found in Appendix D.

The System Service requirements projects do not approach the materiality threshold. Two activities of note are the replacement of porcelain lightning arrestors and the installation of one switch per year to the end of 2019. The lightning arrestor replacement need originated from the reliability analysis and also included safety concerns with the failure mode of these devices. The switch installation addresses the ability to sectionalize the system into smaller sections making it possible to

restore power to more customers by switching rather than completing a repair before restoring power. This will reduce the CAIDI and SAIDI statistics once the switches are installed.

Historically HPDC has not had solid documented processes that generated the capital programs. In addition after the recession of 2008 a forest products plant, one of three at the time, closed due to the economic situation. This reduced the load on the power system by about 5 MW or over 25%. This load has not been recovered and hence no system load driven projects are required.

The plant capital expenditures from 2010 to 2013 are shown in table 9 below.

	Test-5			Test-4			Test-3			Test-2		
	2010			2011			2012			2013		
	Plan	Actual	% Var	Plan	Actual	% Var	Plan	Actual	% Var	Plan	Actual	% Var
Category	$			$			$			$		
System Access												
System Renewal	53,300	18,254	-65.8%	58,499	13,861	-76.3%	58,001	22,268	-61.6%	58,486	19,771	-66.2%
System Service	30,300	0	-100.0%	5,000	5,338	6.8%	2,500	197	-92.1%	2,500	7,258	190.3%
General Plant	67,550	5,236	-92.2%	205,500	26,780	-87.0%	67,000	241,825	260.9%	44,250	31,933	-27.8%
Capital Contributions												
Change in WIP												
Total	151,150	23,490	-84.5%	268,999	45,979	-82.9%	127,501	264,290	107.3%	105,236	58,962	-44.0%
Subtotal Distribution System Capital (excluding General Plant)	83,600	18,254	-78.2%	63,499	19,199	-69.8%	60,501	22,465	-62.9%	60,986	27,029	-55.7%

Table 9 Historical Variances Plan to Actual 2010 to 2013

As can be seen, the plant capital plan-to-actual figures have a large variance. In early 2014 the previous General Manager left and a new General Manager was hired. The planning and rationale for the capital work that was completed prior to 2014 were undocumented decisions made by the previous GM for which we have no explanation. Going forward the activities that generate the budget dollar requirements will be planned and documented and completed as budgeted

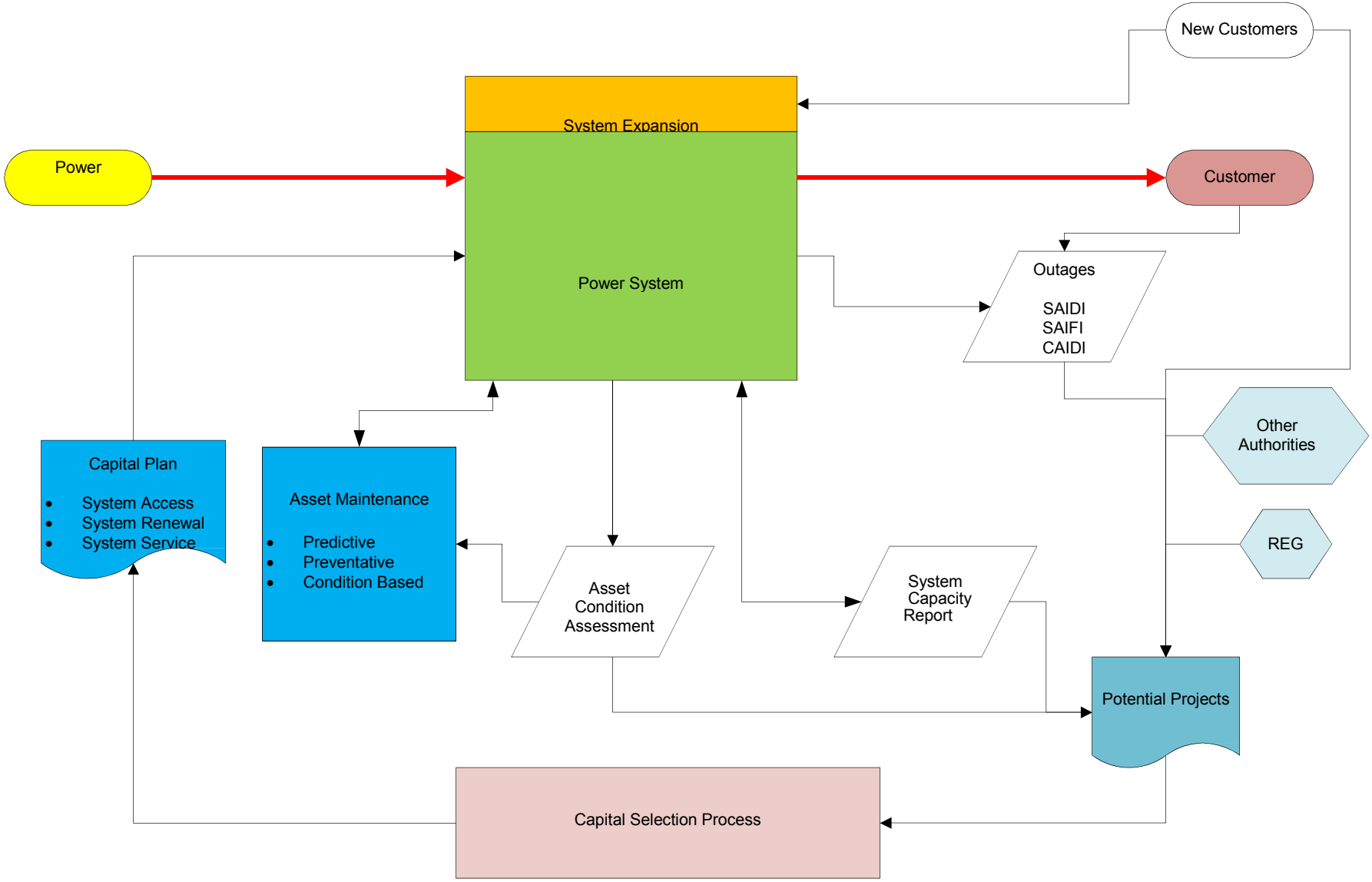
The current plan for 2014 has been reviewed and the work planned is forecast to be completed. In addition urgent pole replacements identified in the pole condition survey were addressed so that the System renewal cost is over budget with the total plant capital being 20% over budget. However to put this into perspective the absolute dollar magnitude is about $17,000.

Moving forward, because of the heightened awareness of the Hearst Power Board, a new General Manager and this rate filing process, HPDC expects that the condition based System Renewal program and the actual performance based System Service expenditures each with specific defined projects will result in a much better match of plan to actual expenditures. HPDC is committed to ensuring that this is the case.

3. (5.4) Asset Management Process

3.1. (5.4.1) Asset Management Process Overview

HPDC has no written asset management objectives or written corporate goals at present. This will be addressed moving forward. HPDC does have current practices that guide its' activities. Below is the basic process HPDC is using moving forward with the planning process.



Asset Management Process Overview

As can be seen from the flow chart potential projects can be initiated externally by new customers, by other authorities and by new REG installations. For Hearst at this time none of these external drivers have generated any potential projects.

Internal potential project sources are the reliability performance of the system, the capacity of the system to supply load and the asset condition assessment. For HPDC the system capacity does not generate any potential projects. However the age of the pole assets, as recorded in the asset registry, has caused HPDC to do a more detailed assessment of the condition of a subset of its poles namely those poles that have been in service for 35 or more years. This has generated 126 locations to be replaced. Also a review of the outage performance of the system has pointed to porcelain type lightning arrestors creating outage performance problems and public safety issues. This has also produced a potential project.

The general inspection as required by the Distribution System Code also impacts the condition based maintenance activities and may change the preventative maintenance program. Also some potential capital projects may be initiated. Neither of these have been the case at this time in preparing this DSP.

The potential projects are reviewed before including them in the approved capital plan. The first process is to determine if the project is necessary and what the scope and cost is. Here the first determination is to see if it is discretionary or non-discretionary work. Customer work, REG work and work from other authorities are non-discretionary. As indicated elsewhere HPDC has no potential projects from these sources except for minor customer service work hence their capital program is almost exclusively discretionary.

The next process is to determine what the justification is for the project, the scope and magnitude and if the project can logically and cost effectively be completed in a staged manner over two or more years. The major criteria for justification are safety for the public but also for HPDC staff working on the lines. Next is addressing the reliability impact for the customers. It is not the intent to improve the reliability on an ongoing basis but to prevent the degradation of reliability or restore it to desired levels if it has degraded. Also ensuring that adequate capacity and flexibility exists in the power system to supply its' customers not just from a prime load perspective but also in first contingency situations. System capacity is adequate but some improvement is required in the system flexibility to be able to restore customers quickly. This is addressed in the capital plan.

Power quality has not been a problem for HPDC.

3.2. [5.4.2] Assets Managed

HPDC distributes power at 25kV which is a 3 phase - 4 wire grounded Y system. The power is supplied from Hearst TS which is a Hydro One owned and operated facility. HPDC is supplied by three feeders from Hearst TS. Two of the feeders are owned by Hydro One [poles and structures and primary conductor] since they supply power to Hydro One customers outside the HPDC service territory. Only the “main feeder” elements of the feeders required to deliver power beyond the HPDC service territory are owned by Hydro One. All distribution equipment such as transformers and secondary conductors that are mounted on the Hydro One owned Poles are owned by HPDC. All laterals and the “none main feeder” elements are owned by HPDC. The third feeder from Hearst TS is also owned by HPDC. For the two feeders owned by Hydro One, there are primary metering units at entry and exit points of the feeders so that the HPDC load is accurately recorded.

The area serviced by HPDC is 98.67 square km. this area is a mixture of urban – the Town of Hearst and rural in the area immediately outside the Town centre and the built up residential area. The weather conditions are typical of northern Ontario with cold winters and significant snowfall and the potential for short hot summers.

The distribution system is mostly overhead with some underground that was installed mostly in the 1970’s to the 1990’s.

The economy is mainly driven by the forest products industry. Other businesses support this primary industry or provide services to the people employed in forest products. The economy in the area has slowed when one of three operating mills was shut down about seven years ago. The load has not recovered from this event but it has remained steady at the lower value subject to variations due to weather. HPDC does not anticipate any major economic changes in the economy over the forecast period. Hence no growth is anticipated and this is reflected in the forecast activities.

HPDC has the following distribution assets:

Primary circuits (25kv)		
Overhead	3 phase	23.3 km
Overhead	1 and 2 Phase	40.3 km
Underground	3 phase	1 km
Underground	1 and 2 phase	6.4 km
Secondary circuits		
Overhead		17.2 km
Underground		9 km

Table 10: Primary and Secondary Lines Information

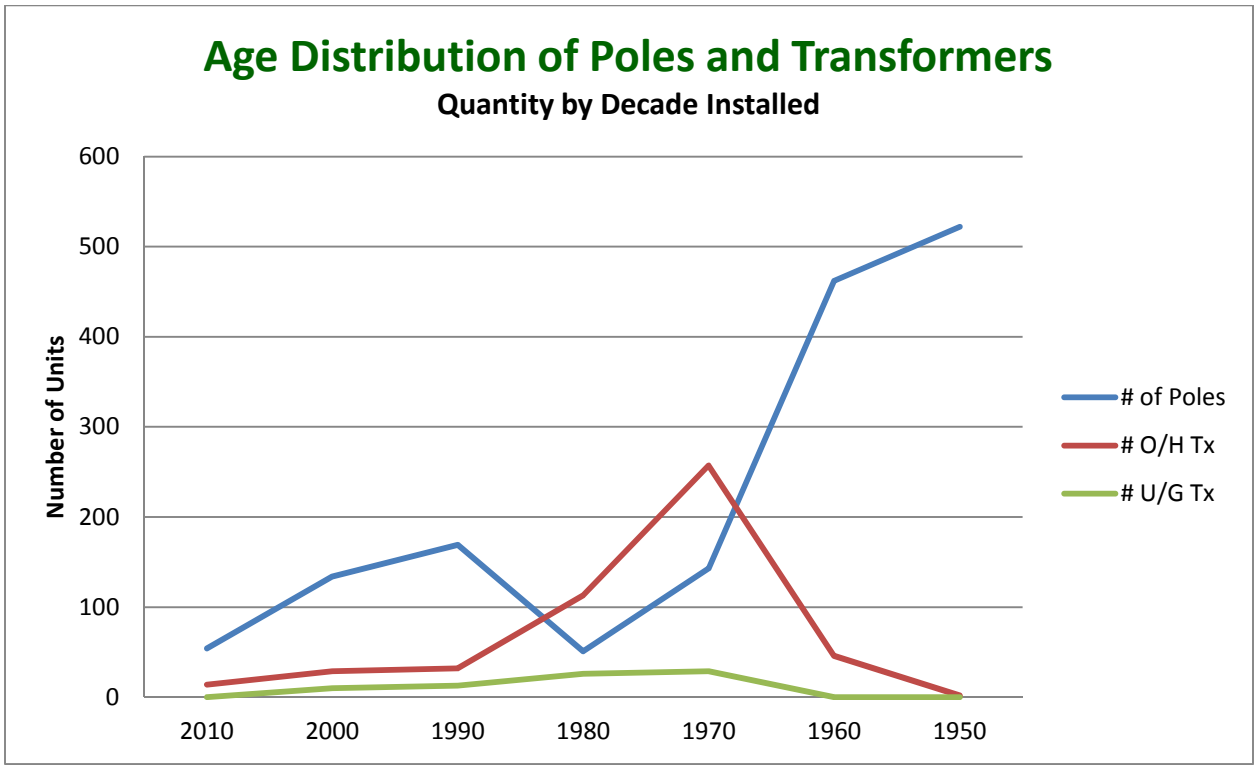
Poles	
Pole height	**Quantity**
25	30
30	116
35	645
40	557
45	158
50	8
55	6
Total	**1520**

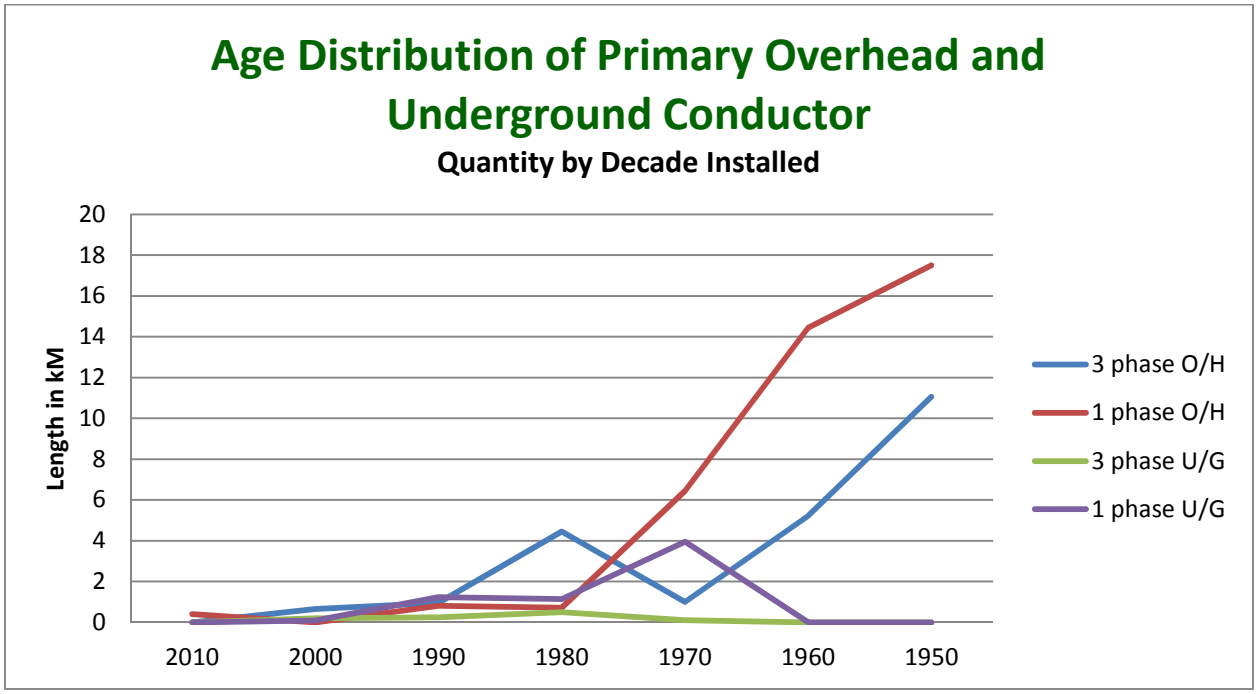
Table 11: Pole Information

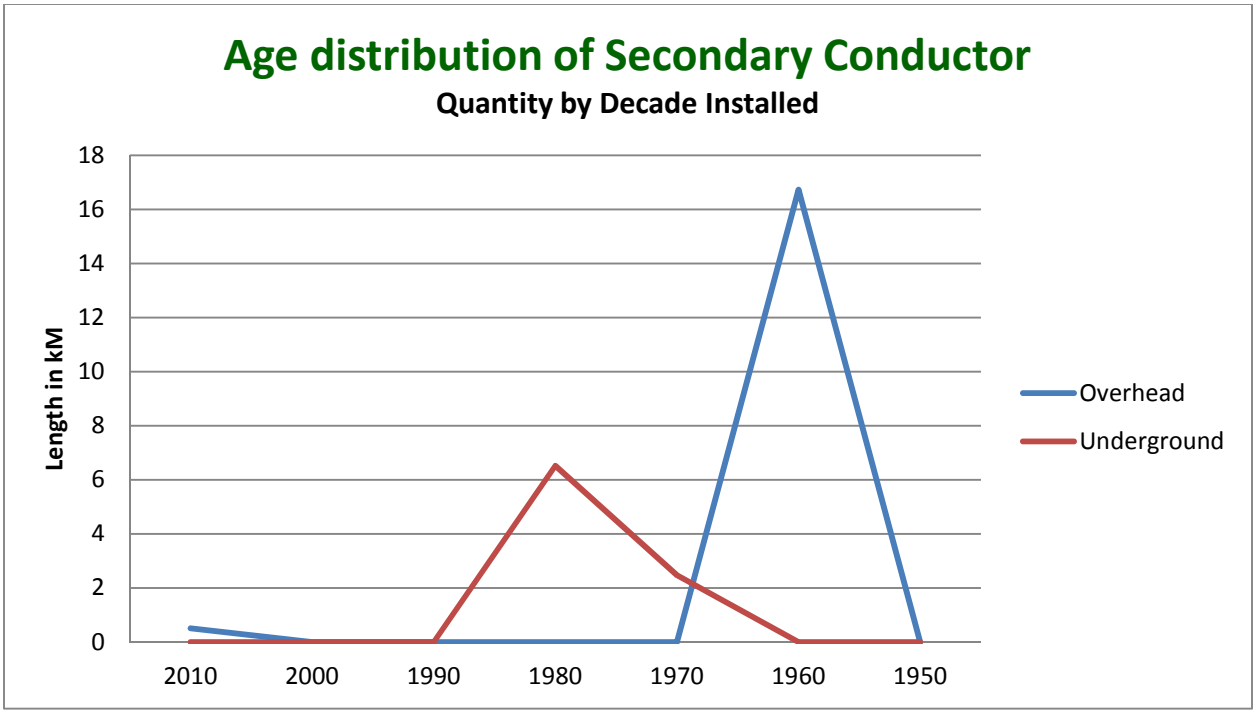
Transformers	
Overhead	
Size (KVA)	Quantity
5	11
10	44
15	11
25	247
37.5	11
50	166
75	41
100	5
150	1
Total	537
Underground	
Size (KVA)	Quantity
50	29
75	28
100	6
150	2
300	5
500	5
Total	75

Table 12: Transformer Information

The following graphs show the quantity of the assets in service by the decade they were installed.







The information in the tables and graphs is current as of July 2014.

The graphs show that significant fractions of the installed plant particularly the overhead plant are 40, 50 and 60 years old. This is a concern and inspections are carried out to identify deteriorated plant that needs to be replaced. An inspection was carried out in 2009 and this inspection identified the assets that needed to be replaced. This plan has been completed in 2010 to the present. In 2014, an inspection of the oldest pole assets [installed in the 1970's and earlier so 35 years and older] was conducted. The details of the inspection can be found in Appendix E. This inspection measured seven factors to determine an overall rating for the pole condition. This process identified 126 poles that had significant deterioration and this is the driver for the pole replacements which is part of the Capital program - system renewal.

The capacity of the power system is adequate to supply the existing loads. The current load is in the order of 13 MW which is a drop of about 5 MW from several years ago. The closure of a forest products plant several years ago caused the drop in load. The current system has the ability to provide prime load. There is backup capability to perform load transfers to allow planned work to proceed as well as sectionalizing to restore power in outages. Voltage levels are maintained throughout the system to the required standards. Hence there are no requirements to expand the capability of the system at this time or in the foreseeable future given the current economy and economic outlook.

3.3. [5.4.3] Asset Lifecycle Optimization Policies and Practices

HPDC has no policies for this at this time. As a result of this DSP, HPDC plans to create written practices or policies as appropriate so that the organization provides clear objective direction to staff.

This will be important as retirements and other personnel changes occur in the ongoing activities of the organization.

The distribution assets of HPDC do not include any Municipal Station or Transformer Station equipment which is high cost, long delivery, long lead time delivery items. Consequently the current practice typically is to run assets to failure except where doing so results in safety issues for either the public or the line staff in normal operation or the system reliability is adversely affected.

The other exception is wood poles where a survey was carried out and end of life poles were identified and are replaced before they fail in service. This is done to manage the workload and the cost since multiple failures could happen in adverse weather and this would result in long restoration times since HPDC only has one 2 man line crew.

Load interrupter switches are maintained to the manufacturer's recommendations because these devices need to be operable to reconfigure the power system when power failures occur to restore power to as many customers as possible.

HPDC carries out the following routine maintenance activities:

- Predictive Maintenance:
    - Routine inspections as required by the Distribution System Code. Deficiencies are logged and completed as Condition Based Maintenance.
    - Condition assessment of poles more than 30 years in service. The program is documented in Appendix E.
- Preventative Maintenance:
    - Regular vegetation management. Based on a regular cyclical geographically based schedule as well as input from the routine inspections.
    - Load interrupter switch maintenance
- Condition based Maintenance:
    - Repair of all deficiencies noted in the routine inspections and any items discovered when operating the system.

Risk is managed by being aware of the failures that occur on the power system and being aware of any safety consequences that are likely to accompany the failure. For example when a porcelain, air gap type of lightning arrestor fails, typically the porcelain shatters into various sized sharp fragments and these are propelled at high speed in all directions. This clearly presents a safety hazard for any person in the immediate vicinity of the device when it fails catastrophically. The replacement of these lightning arrestors will begin where people are most likely to be in the vicinity if a failure occurs and the last ones to be replaced will be those in a rural setting.

Similarly pole replacement is scheduled to take place at a steady pace beginning with the poles in the worst condition. The condition is determined by an assessment process which is detailed in Appendix E.

Capital expenditure selection is on the basis of the following in priority order:

- Regulatory requirement or obligation
- The safety impact on the public and staff
- Reliability impact

- Outage causes and frequency
- Restoration capability
- Power quality

Timing and pace is determined by:

- Manpower capability to complete the work
- The financial ability to pay for the work
- Completing the expenditures that provide the greatest benefit
    - For example the lightning arrestor replacement is completed in a two year timeframe because of the safety concerns while the pole replacement takes place over a five year timeframe because of a lower safety impact.

HPDC's main distribution assets are poles, overhead wire, transformers, switches and switch fuses as well as underground primary cable, transformers and secondary cable.

All the distribution plant is inspected as a minimum on a three year cycle in accordance with the Distribution System Code requirements.

In addition poles that are more than 35 years old are checked in detail every 4 years and a condition assessment is carried out on them. The assessment was formalized in 2014 and Appendix E contains the details of what the assessment entails. HPDC has 1123 poles that are in service for more than 35 years. These were tested and 126 were identified as needing to be replaced. These replacements are included in the capital program for 2015 and beyond. The oldest poles were fully treated when installed and they have given excellent service as can be seen by the modest 11% that need to be replaced even now.

Both the primary and secondary overhead wire are maintained minimally on a planned basis. There is a visual inspection as part of the Distribution System Code inspections. Situations requiring repair are noted and follow-up is initiated and carried out. There is a Thermographic scan of connections to identify if the connections are overheating and vegetation is managed to ensure there is adequate clearance between the lines and any trees or other vegetation that could interfere with the operation of the power system.

Overhead transformers are inspected visually as part of the Distribution System Code requirements and identified problems are corrected. Approximately 91% of the transformers are 50kva or smaller and the strategy is run to failure for existing units. If there is an activity such as a new service connection the transformer size will be reviewed and upgraded as required.

Overhead switches are inspected per the Distribution System Code requirements and are maintained per the manufacturer's recommendations.

Overhead Switch/fuses (cutouts) are inspected per the Distribution System Code requirements and are inspected when they are operated manually by a crew or after they operate automatically when the fuse protection operates. Damaged cutouts are replaced.

Underground transformers are inspected per the Distribution System Code requirements. The inspection includes looking for rust which is cleaned off and painted at a later time, and checks the

concrete base for cracks etc. that create public safety and transformer stability issues. These are identified and replacements are done as part of the capital program.

Underground primary cables have not failed in HPDC's system. Cable terminations are inspected visually in pad mounted switching units and in transformers. Unless problems are discovered they are run to failure.

Underground secondary cable terminations are visually inspected at the transformer when the transformer inspection is carried out.

For HPDC, end of life pole replacement is the only material system renewal spending item at this time and for the foreseeable future.

The pole condition assessment process followed by HPDC is documented in Appendix E. The result of the process is that based on the condition assessment carried out 20 poles are replaced each year in 2015 and beyond beginning with the most at risk poles. In 2019 a new survey of the condition of the poles will be carried out on the poles that have been in service for 30 years or more. Based on this survey a new rate of pole replacement will be established and this will be reflected in the capital program.

The regular maintenance that is carried out on the overhead circuits is the vegetation clearing and visual inspections as required by the Distribution System Code.

4. [5.5] Capital Expenditure Plan

4.1. [5.5.1] Summary

HPDC's customer base is approximately constant. There are no new developments being planned in the service territory nor are there any known contractions in the number of customers. Consequently there is no growth driver for capital plant. The system load is currently about 13 MW while before the third forest products plant closed several years ago the load was about 18MW. The current power system served this load adequately. Hence no new lines are required to supply the current load.

The current capital expenditures over the forecast period are shown in Table 13 in section 4.4[5.5.4]. There is only one project that exceeds the materiality threshold namely the pole replacement program.

HPDC's capital program was developed by outputs of the Asset Management and the Capital Planning process. The activities by investment category are summarized below.

System Access Projects:

- There are no material projects initiated in this category. There are no projects initiated by other authorities, nor by system expansion requirements nor by Renewable Energy Generation. There are only a few small customer service type projects.

System Renewal Projects:

- There is only one “material” project in this category namely the pole replacement program.
- This program resulted from the visual inspection of the distribution plant and the analysis of the age distribution of poles. It was decided to perform a condition assessment as detailed in Appendix E. This assessment resulted in a defined scope, time based project as reflected in the budget forecast.

System Service Projects

- There are no “material” projects in this category. HPDC plan to replace their remaining porcelain lightning arrestors over the 2015, 2016 time periods.

General Plant Projects

- There are no “material” projects in the category.

The capital projects for each category for the 2015 to 2019 period are included in Appendix C. Only the System Renewal – pole replacement program is material in the capital program.

No Regional Planning Process has been carried out to date as note in the OPA reply to the REG report. A study is being planned to commence about the end of 2015. Hence the process has not had any input into the current planning process.

HPDC has completed a residential customer survey in 2014. While the responses were positive about HPDC’s performance as a service company and as a corporate citizen, the survey also indicated that the customers have a high sensitivity to the retail cost of power. HPDC has used this input to be frugal with its’ capital expenditures and has spread work to be done over a time period to minimize the customer bill impact that it originates.

HPDC expects its load and its customer base to be essentially static over the next five years. It does not anticipate any requirements to make expenditures for REG or Smart Grid projects at this time.

4.2.[5.5.2] Capital Planning Process Overview

As stated in section 3.1 [5.4.1] HPDC does not have written planning objectives or written planning criteria. If the practices were to be summarized it could be captured as “Deliver safe, reliable power to its customers at a reasonable cost in a long term sustainable manner”.

Having said that much of what HPDC is doing is simple. As shown in section 3.1 [5.4.1] there are only a very few proposed capital projects because at this time there are no outside drivers for system capital work including REG related projects and it is only reliability and end of asset life concerns that result in any proposed capital projects. These specific projects are not influenced by any maintenance programs. Maintenance would be considered if it could be effective to prevent capital spending or extend the life of an asset economically.

There is no system capacity issue at this time in HPDC’s service territory.

HPDC has a very modest capital plan that has a relatively small impact on the customer's power bill. However HPDC is sensitive to this impact and attempts to do only what is necessary to be done and also smooth the capital expenditures.

To do this the projects are reviewed if they can be completed economically over the course of two or more years and what the impact of this smoothing will be. The result may be the same total cost or the total cost may be higher as a result of this smoothing. Also the benefits are only achieved to the extent that the work is completed. This was considered when the lightning arrestor replacement program was planned to be completed over two years in order to achieve the safety and outage reduction benefit sooner.

Customer engagement was formally done for the residential customers by way of an opinion survey in 2014. The survey and the results can be found at Exhibit 1, Tab 2, Schedule 2.. The Survey indicates that HPDC performs well and is regarded highly as a corporate citizen. The customers did indicate that many of them have concerns for the size of their power bills. HPDC takes this into account as it plans its' programs and budgets.

There are no REG investments planned at this time because there are no known REG projects and there are no requests for connection.

4.3.[5.5.3] System Capacity Assessment for Renewable Energy Generation

HPDC has 52 approved MicroFIT solar generators under contract and connected to its system for a total of 516.48 kW. It also has one large approved solar generator under contract with a capacity of 10 MW connected to its system.

HPDC is supplied by Hearst TS which is owned and operated by Hydro One. The station capacity information which can be found at ***http://www.hydroone.com/Generators/Documents/HONI_LSC.PDF*** indicates that the station is transmission constrained and as such no additional Renewable Energy Generation (REG) can be accepted at this time.

There are no outstanding active applications for any REG projects at this time. Hence HPDC has no requirement for REG enabling projects at this time. If the transmission constraints are resolved and rescinded then there may be a need but this is not likely in the foreseeable future. Hence no system access projects for REG are included in the budget forecast.

4.4.[5.5.4] Capital Expenditure Summary

The capital expenditures of HPDC are modest and as a result there are few identifiable separate "projects" to be reported on. As a result the budgeting is typically done using the financial account structure as is the reporting. Consequently the tables below which outline the historical expenditures and the capital forecast to 2019 use the account structure. Further there is only one activity that of pole replacement in the system renewal category that exceeds the materiality threshold in the forecast period. A justification for this project can be found in Appendix D.

Because of the management processes of the previous General Manager no planned figures could be found for the individual lines that make up a capital category. The total for the category is available and is shown on the tables as is the actual expenditure by account number. The forecast period includes the plan amount for each account in the capital category.

Table 13 below shows the historical expenditures from 2010 to 2013, the current year forecast expenditures the test year planned expenditures and the forecast expenditures for 2016 to 2019.

Appendix C has the detailed expenditures and explanations for variances on material projects.

Capital Expenditure Summary																				
	Historical (Previous Plan and Actual)												Forecast (Planned)							
	Test-5			Test-4			Test-3			Test-2			Test -1			Test	Test +1	Test +2	Test +3	Test +4
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	% Var	Plan	Actual	% Var	Plan	Actual	% Var	Plan	Actual	% Var	Plan	Forecast	% Var	Plan	Plan	Plan	Plan	Plan
Category	$'000			$'000			$'000			$'000			$'000			$'000	$'000	$'000	$'000	$'000
System Access														33		11	12	13	14	15
System Renewal	53	18	66	58	13	78	58	22	62	58	20	66	47	64	-36	86	95	100	105	110
System Service	30		100	5	5	0	3		100	3	7	-133	0	2	100	19	21	6	6	7
General Plant	68	5	93	206	27	87	67	242	-261	44	32	27	104	80	23	60	48	39	51	67
Capital Contributions														-33		-11	-12	-13	-14	-15
Change in WIP																				
Total	151	23	85	269	45	83	128	264	-106	105	59	44	151	146	3	165	164	145	162	184
System O&M	380	385	-2	392	418	-7	456	479	-5	462	473	-2	512	515	-0.6	552	525	550	580	620

Table 13 Capital Expenditure Summary

4.5. [5.5.5]Justifying Capital Expenditures

4.5.1. [5.5.5.1] Overall Plan

The comparative expenditures made by HPDC in the capital categories are shown below:

Capital Expenditure Summary										
	Historical (Actual)				Forecast (planned)					
	Test-5	Test-4	Test-3	Test-1	Test-1	Test	Test +1	Test +2	Test +3	Test +4
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Actual	Actual	Actual	Actual	Forecast	Plan	Plan	Plan	Plan	Plan
Category	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Access					33	11	12	13	14	15
System Renewal	18	13	22	20	64	86	95	100	105	110
System Service		5		7	2	19	21	6	6	7
General Plant	5	27	242	32	80	60	48	39	51	67
Capital Contributions					-33	-11	-12	-13	-14	-15
Change in WIP										
Total	23	45	264	59	146	165	164	145	162	184
System O&M	385	418	479	473	515	556	525	552	580	620

It should be noted that the future costs include the estimated effect of cost increases over time. The descriptions for the projects are provided in Appendix C. As can be seen in Appendix C the work in the System renewal project is identical for 2015 to 2019 but there is an adjustment to project real expected costs in each year.

As noted in section 2.1.3 [5.3.3] the historical period was overseen by a previous General Manager. These expenditures do not represent the real needs of the HPDC power system nor are these expenditures consistent with a long term, sustainable, economical, well-functioning distribution system.

The capital program for system renewal will, in the case of the pole replacement program, prevent an increase in operating cost as end of life deteriorated poles fail in service. This will not decrease the current operation and maintenance cost. The lightning arrestor replacement program has made cost contributions to the operating and maintenance costs of HPDC. These costs will reduce once the failure prone arrestors are replaced. As actual experience shows the cost reduction the O&M budget will be adjusted appropriately. The failures and hence the costs due to arrestor failure were not predictable in any one time period. Hence the impact is not as predictable as one would like but the fact that failures occurred and that these impacted reliability and costs is clear. The expected saving should be apparent in two or three years after the replacement is completed.

There is no material System Access related material work because there are no drivers at this time as indicated in sections 2.1.1 [5.3.1].

There is one System Renewal project that HPDC intends to complete starting in the test year. These are the pole replacement program as identified in sections 2.1.3 [5.3.3]; 3.2 [5.4.2] and 3.3 [5.4.3]. The driver is the deteriorating condition of aging plant. This will not improve going forward and the only solution is to replace the poles. The project is a strict one for one replacement complete with reattachments of existing devices and foreign plant. The replacement is on a condition basis and no street rebuilds are completed if all the poles do not need replacement.

There are two system service projects HPDC intends to complete starting in the test year. First is the lightning arrestor project. This project is driven by customer service and the deteriorating reliability that these devices contribute to as well as the safety hazard they can be when they fail. These drivers will not decrease until they are replaced either through failures or replacement on a planned basis. This information has been expressed in Sections 2.1.1 [5.3.1], 2.1.3 [5.3.3] ,3.3 [5.4.3] and others.

The second project is not material but addresses the flexibility of the system to be able to restore parts of a locked out feeder. HPDC will be installing one switch per year for the test year and the forecast period (2015 to 2019) to achieve this added flexibility. This is a low cost way to ensure the system reliability measures are maintained. The driver has been the deterioration in the SAIDI statistic in 2012 and 2013. As shown in Section 2.1.3 [5.3.3]

There is no material General Plant projects planned for 2015 to 2019. In 2012 a new bucket truck was purchased and outfitted and in 2014 the service center / warehouse was upgraded to make it more energy efficient.

4.6. [5.5.5.2] Material investments

4.6.1. General Information on project / Activity

The materiality threshold for HPDC is $50,000. There is only one project in the 2015 to 2019 period that reaches the materiality threshold and it is the pole replacement program. The expected costs of this program in this period are shown below:

System Renewal	2015	2016	2017	2018	2019
1830 - Distribution Overhead - Replace Poles (20)	$70,000	$73,500	$77,175	$81,034	$85,085
1835 - Distribution Overhead - Overhead Conduits	$5,000	$5,250	$5,513	$5,788	$6,078
Total	$75,000	$78,750	$82,688	$86,822	$91,163

The project is planned to start in the spring of 2015 and proceed at a rate of 20 poles per year to the end of 2019. There are no known risks to the completion of the project neither at this time nor for the complete period.

4.6.2. Evaluation Criteria and Information Requirements for Each Project / Activity

Efficiency, Customer Value and Reliability

The main driver for the pole replacement program is the risk of plant failing in service and creating long outages for customers and added O&M costs for the utility. This is intensified if there are simultaneous failures if the failures are the result of weather stressors such as high winds. HPDC only has one line crew to respond to these situations.

The priority for this investment is relatively high but the lightning arrestor replacement is a higher rated project but it does not meet the materiality threshold. This is also the reason that the pole replacement project is spread over 5 years. The data in Section 3.2 [5.4.2], particularly the age of plant together with the results of the pole assessment that was carried out, which is described and reported in Appendix E, support the pole replacement project. When there is only one material project it is difficult to respond to the nature of the prioritization process in anything beyond a trivial manner.

Safety

There are some safety benefits to doing the pole replacement project. First is the reduction of the possibility of poles falling in adverse weather and causing accidents or damage to property. Second is the safety related to the potential loss of power during extreme cold weather and the loss of heat for an extended period of time.

Remaining criteria

The other criteria are generally not applicable to HPDC's situation

4.6.3. Category-Specific Requirements for each Project / Activity.

System Access

There are no material projects.

System Renewal

All the poles planned to be replaced are from the 1950's, 1960's and 3 poles from the 1970's. all the poles from the 1950's and 1960's were part of the original electrification carried out by the then Ontario Hydro. These poles have provided excellent service namely in the order of 50 plus years. The 5 year replacement program represents about 11% of the number of poles in this age bracket (more than 35 years of service). HPDC does not do maintenance on the poles. The poles in question have strength and mechanical integrity issues that cannot be addressed by pole treatments or other maintenance activities. Replacement is the only option and HPDC has decided to replace like for like. This is the lowest cost approach and it meets the needs of the customers (keep costs low) and the utility (restore the poles structures to the required strength).

Customers are connected to three feeders. Each feeder has a mixture of residential, commercial and industrial load. The deteriorated poles affect each feeder. Therefore all the customers have a risk of power interruptions due to pole failures. This risk will grow if no planned replacement project is initiated. Also in service failures will increase the O&M costs as a result of emergency replacements and repairs.

System Service

There are no material system service projects.

General Plant

There are no material general plant projects.

5. APPENDIX

Appendix Section

A. 5.1 OPA Reply to Renewable Energy generation Report by Hearst Power Distribution Company Ltd.
B. 5.2 Outage incidents January 2010 to June 2014.
C. 5.3 Capital program details and explanations
D. 5.4 Justification for the Pole replacement Program
E. 5.5 Pole Inspection Process – Poles in Service More Than 35 Years
F. 5.6 Pictures of HPDC Warehouse.

5.1. Appendix A

OPA Reply to Renewable Energy generation Report by Hearst Power Distribution Company Ltd.

OPA Letter of Comment

Hearst Power Distribution Company Limited

Renewable Energy Generation Investments Plan

ONTARIO POWER AUTHORITY

July 23, 2014

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Hearst Power Distribution Company Limited – Distribution System Plan

On July 9, 2014 Hearst Power Distribution Company Limited ("HPDC") provided its System Capability Assessment for Renewable Energy Generation Investments to the OPA as part of its 5-year Distribution System Plan. The OPA has reviewed the information in HPDC's Assessment and has provided its comments below.

OPA FIT/microFIT Applications Received

On page 2 of the Assessment, HPDC indicates that it has connected 52 microFIT projects totaling 516.48 kW of capacity, and 1 FIT solar projects totaling 10 MW of capacity, and that it has no active applications for connecting renewable energy generation projects at this time.

HPDC indicates that it is supplied by Hearst TS which is owned and operated by Hydro One, and because the station is constrained that no additional REG can be accepted at this time. Hearst Power Distribution Company Limited has also indicated that these constraints are not likely to be resolved in the near future and has therefore not included any REG investments in its budget forecast as part of its Distribution System Plan.

According to the OPA's information, as of May 2014, the OPA has offered contracts to 52 microFIT projects totaling 516.48 kW of capacity, and 1 FIT project totaling 10 MW of capacity, all of which are still active to date.

Ontario Power Authority

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The OPA finds that HPDC's information is consistent with OPA's information regarding renewable energy generation applications to date.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The OPA notes that Hearst Power Distribution Company Limited is part of the "Group 3" – North/East of Sudbury region for regional planning purposes. At this time, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has been completed for HPDC's service territory. The regional planning process for the North/East Sudbury region is not anticipated to start until late 2015. As a result, the OPA has no comment on the following three items outlined in the Chapter 5 filing requirements, specifically:

- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The OPA looks forward to working with HPDC on regional planning once that process is triggered for the area, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.

5.2.Appendix B

System Outage Detailed Information

January 2010 to June 2014

Outage Detail 2010

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer Hours
					A	B	A x B
Mar-23	ALL FEEDERS	2	Loss of Supply	H1	2755	0.05	137.75
MAR. 14	94 FONTAINE	5	Lightning	REPLACE FUSE	8	1	8
Mar-27	CEZAR BOWLING	5	Defective Equipment	CHANGE SURGE ARRESTORS	1850	0.75	1387.5
Apr-01	Corner 9th & 10th	5	Defective Equipment	blown lightning arrestor	20	0.25	5
May-23	Hwy 11 West	2	Loss of Supply	No power on M2	1850	3.5	6475
May-24	41-9th st.	5	Defective Equipment	replace fuse	12	3.5	42
May-31	West,Mongeon						
	St.Laurent,Pearson	5	Defective Equipment	Blown junction & elbow	80	2.75	220
Jun-02	Nor Building	9	Foreign Interference	1504 Hwy 11 West-bird	1	0.75	0.75
Jun-04	812 Alexandra	9	Foreign Interference	Crow	40	1	40
Jun-08	Villa Beausejour	5	Defective Equipment	replace 6 amp fuse	1	0.75	0.75
Jun-29	2 Girard Drive	5	Defective Equipment	No Power - change 3 amp fuse	1	1	1
Jul-07	1408 PRINCE	1	Scheduled	OPEN TRANSFORMER	10	0.5	5

Date	**Location**	**Code**	**Description**	**Cause**	**Customer Interrup. No. Customers affected**	**Duration (Hours)**	**Customer Hours**
Jul-11	Blais Road	5	Defective Equipment	change 40 amp fuse	10	1	10
Jul-19	Boucher Cres.	1	Scheduled	Repair Transformer	10	0.25	2.5
sept. 13	Lecours Trailer Park	1	Scheduled	Mobile home on fire	12	0.25	3
Sept. 24	Bryant St.	5	Defective Equipment	change fuse & untap	20	1	20
Oct. 13	135 Gaspésie Rd	9	Foreign Interference	squirrel	1	0.5	0.5
DEC. 6	Boulley St.	1	Scheduled	open transformer	10	0.25	2.5
Dec. 12	all M2	2	Loss of Supply	Hydro One	1850	4.5	8325
Dec.30	Boulley St.	5	Defective Equipment	replace fuse	6	0.5	3
					8547	**24.05**	**16689.25**

Outage Detail 2011

Date	**Location**	**Code**	**Description**	**Cause**	**Customer Interrup. No. Customers affected**	**Duration (Hours)**	**Customer Hours**
					A	**B**	**A x B**
JAN 16	410 Prince Apt A	5	5 - Defective equipment	Broken fuse	20	0.75	15
JAN 23	Hwy 583 South	7	7 - Adverse Environment	Garage on fire & spark all over	2	1	2
APRIL 28	12 Begin rd.	5	5 - Defective equipment	Change a fuse cutout switch	1	0.75	0.75
MAY 3	213 McNee	5	5 - Defective equipment	Change 3 amp std fuse	1	1.25	1.25
MAY 18	53 Proulx rd	5	5 - Defective equipment	Change TX	2	2	4
JUNE 16	1825 Hwy 11 W	5	5 - Defective equipment	Broken fuse	2	1	2
JUNE 21	Lac St-thérèse rd	2	2 - Loss of Supply	Hydro One - PME PT Burned - M2	2063	3.5	7220.5
JULY 9	45 Labelle st	9	9 - Foreign Interference	Fuse Blown (Crow)	8	1	8
JULY 18	48 Riverside dr.	9	9 - Foreign Interference	Fuse Blown (Crow)	23	0.5	11.5

Date	**Location**	**Code**	**Description**	**Cause**	**Customer Interrup. No. Customers affected**	**Duration (Hours)**	**Customer Hours**
AUG 1	1 Blais rd.	5	5 - Defective equipment	Replace 3 amp fuse	1	1	1
AUG 14	1007 Georges st.	9	9 - Foreign Interference	Fuse Blown (Birds)	10	1	10
SEPT 27	510 & 519 Georges st.	5	5 - Defective equipment	Lightning, switch, fuse blown	15	1	15
OCT 23	218 Hwy 11 East	5	5 - Defective equipment	Broken insulator pin	419	1	419
NOV 14	1126 Prince st.	3	3 - Tree Contact	Replace damaged tripex due to tree	1	1	1
NOV 20	42 - 15th street	5	5 - Defective equipment	Damaged elbow & bushing well + fuse	75	3.5	262.5
DEC 15	98 Despres rd	5	5 - Defective equipment	Broken fuse	1	1	1
					2644	**21.25**	**7974.5**

Outage Detail 2012

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer Hours
					A	**B**	**A x B**
MAR 28	Corner Allen & Rousse st.	5	5 - Defective equipment	Blown switch and fuses	30	2.25	67.5
APRIL 15	45 Rousse st.	5	5 - Defective equipment	Broken switch	6	1	6
APRIL 14	3rd street	2	2 - Loss of Supply	M3 feeder was out (blown lightning arrestor)	304	1.25	380
APRIL 17	18 Hwy 11 East	2	2 - Loss of Supply	Interruption due to Hydro One feeder	60	4	240
MAY 6	Morin rd	2	2 - Loss of Supply	Blown fuse	1	1	1
MAY 10	186 McNee st	5	5 - Defective equipment	Broken switch	1	1	1
MAY 20	7th Boulley st.	3	3 - Tree Contact	Tree fell on line	19	1.5	28.5
Jun-19	342 Hwy	9	9 - Foreign Interference	21M2 guy wire from radio tower into primary	2063	3	6189
Jun-19	21M3	6	6 - Adverse Weather	feeder lockout - lightning	304	2.75	836
JUNE 29	Morin Rd.	2	2 - Loss of Supply	Hydro One circuit down	4	1.25	5
JULY 2	708 Prince st	9	9 - Foreign Interference	Blown fuse (bird)	8	1	8

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer Hours
JULY 14	Morin rd.	5	5 - Defective equipment	Broken insulator, blown transformer	1	2	2
AUG 15	Hwy 583 South	9	9 - Foreign Interference	Blown fuses (crow)	5	1	5
AUG 25	507 Edward	9	9 - Foreign Interference	Blown fuse (bird)	10	0.5	5
AUG 26	149 McNee	5	5 - Defective equipment	Blown fuse	1	2.25	2.25
NOV 18	Collin & Bosnick rd.	5	5 - Defective equipment	Replace dead end insulator + fuse	6	1.5	9
NOV 20	302 Bergeron	5	5 - Defective equipment	Blown switch & lightning arrestor	419	1.5	628.5
NOV 20	302 Bergeron			Due to HPD defective equipment, H1 was offline	0	1.5	0
					3242	**30.25**	**8413.75**

Outage Detail 2013

Date	**Location**	**Code**	**Description**	**Cause**	**Customer Interrup. No. Customers affected**	**Duration (Hours)**	**Customer Hours**
					A	**B**	**A x B**
JAN. 16	M1 FEEDER(H1)	2	Loss of Supply	TRANSFORMER ON FIRE	419	1	419.00
JAN. 17	H1 (M1)	2	Loss of Supply	TRANSFORMER ON FIRE	419	5	2095.00
				BETWEEN HEARST & LOWTHER			
							0.00
							0.00
APRIL	510 KITCHENER	9	Foreign Interference	NO POWER - CHANGE 6 AMP FUSE	3	0.75	2.25
							0.00
May-19	M1	2	Loss of Supply	PERMANENT FAULT (H1 PROBLEM)	419	3.5	1466.50
							0.00
May-28	807 FRONT	5	Defective Equipment	REPLACE TRANSFORMER	1	4.5	4.50
Jun-08	Most of the Town M2	5	Defective Equipment	change lightning arrester at 289 Hwy 583 South	2063	1.5	3094.50
Jun-08	Most of Town M2	2	Loss of Supply	Hydro One SCADA communications down. Travelling Operator needed from Timmins. Wait time to restore power.	2063	3	6189.00
Jun-30	53 McNee	9	Foreign Interference	refuse tx & line fuse	10	1.25	12.50
Jul-06	Riverside Drive	5	Defective Equipment	replace broken switch	22	1.5	33.00
Jul-14	8TH STREET	5	Defective Equipment	replace switch & fuses	8	1.5	12.00

Date	**Location**	**Code**	**Description**	**Cause**	**Customer Interrup. No. Customers affected**	**Duration (Hours)**	**Customer Hours**
Jul-15	Piper Street	9	Foreign Interference	crow	12	1	12.00
Jul-17	Labelle Street	5	Defective Equipment	blown transformer	5	1.5	7.50
Aug-04	12 Begin Rd.	4	Lightning	blown fuses	2	2	4.00
Aug. 16	14 Vandette	5	Defective Equipment	blown fuse	3	0.75	2.25
Aug. 21	M3 Feeder	6	Adverse Weather	thunder storm	300	1	300.00
				Totals	**5749**	**29.75**	**13654.00**

Outage Detail 2014 (January to end of October)

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer - Hours
					A	B	A x B
JAN.13	527 Veilleux st.	5	5 - Defective equipment	blown fuses	10	0.5	5
MAR.8	9 Samson rd	5	5 - Defective equipment	blown transformer	1	2.25	2.25
APRIL 26	ALL WYBORN	2	2 - Loss of Supply	broken switch on Hydro One pole	81	2.5	202.5
APRIL 29	CLOUTIER RD NORTH	2	2 - Loss of Supply	BROKEN X-ARM, SWITCH, ARRESTER & FUSE	20	1	20
		2	2 - Loss of Supply		340	1	340
		2	2 - Loss of Supply		1	1	1
MAY 9	TREMBLAY ST.	5	5 - Defective equipment	Defective dead-end insulators which blew fuse	48	1.5	72
MAY 9	TREMBLAY ST.	5	5 - Defective equipment	Defective dead-end insulators which blew fuse	67	0.5	33.5
MAY 19	305 HWY 583 N.	5	5 - Defective equipment	broken switch & refuse	2	18.5	37
MAY 21	TOTAL AREA	2	2 - Loss of Supply	FIE Tripped on Hydro One pole	2777	0	0
MAY 22	TOTAL AREA	2	2 - Loss of Supply	FIE Tripped on Hydro One pole	2777	0.25	694.25

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer - Hours
JUNE 2	East half of St-Pie X and Hwy 11 E	5	5 - Defective equipment	Lightning arrestor	424	2.25	954
June 14	Airport	5	5 - Defective equipment	Replace arrestor and fuse	4	4.25	17
June 21	1589 Hwy 11 west	9	9- Foreign Interference	Replace fuse	1	1	1
June 22	MTO garage on Hwy 11 west	9	9- Foreign Interference	Replace fuse	1	6.75	6.75
July 3	7 Girard drive	1	1 - Scheduled Outage	Planned outage (replace pole)	1	1	1
July 8	58 Cloutier rd South	1	1 - Scheduled Outage	Planned outage (replace pole)	1	1	1
July 10	144 Fontaine	1	1 - Scheduled Outage	Planned outage (replace pole)	2	1	2
July 11	7 Girard drive	1	1 - Scheduled Outage	Planned outage (transfer pri. U/G onto new pole)	1	3.5	3.5
July 14	1649 Hwy 11 W	9	9- Foreign Interference	Crow	1	1	1
July 15	1762 Hwy 11 W	0	0 - Unknown	No apparent cause found (Replaced fuse)	1	1	1
July 16	48 Labelle st	9	9- Foreign Interference	Crow	4	2.5	10
July 17	89 Depres rd.	1	1 - Scheduled Outage	Planned outage (replace pole)	2	1.5	3

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer - Hours
July 21	Riverside drive	4	4 - Lightning	Severe thunderstorms in area	13	1	13
July 22	Riverside drive	3	3 - Tree Contact	Wind cause tree to fall down on hydro pole	26	1.5	39
July 26	Irwin Street	2	2 - Loss of Supply	Broken Switch	2	1	2
July 31	1762 Hwy 11 W	0	0 - Unknown	Unknown	2	0.5	1
Aug 2	100 Rosevear rd.	0	0 - Unknown	Unknown	1	7.25	7.25
Aug 7	West, St-Laurent, Pearson, Mongeon, Flood, Frost, Vanier, Laurier	1	1 - Scheduled Outage	Scheduled outage: replace transformer base	157	3.5	549.5
Aug 21	Airport rd.	1	1 - Scheduled Outage	Scheduled outage: replace pole	5	3.5	17.5
Aug 24	9th Street	5	5 - Defective equipment	Transformer leaking oil	10	1	10
Sep 4	1589 Hwy 11 W	0	0 - Unknown	2 fuses blew, no apparent reason found	1	0.5	0.5
Sep 19	47, 9th street	1	1 - Scheduled Outage	Replaced pole	5	2	10
Sep 24	6, Front street	1	1 - Scheduled Outage	Replaced pole	3	2	6

Date	Location	Code	Description	Cause	Customer Interrup. No. Customers affected	Duration (Hours)	Customer - Hours
Oct 8	2 Fontaine drive	9	9- Foreign Interference	Wires hit by Villeneuve Construction's Truck	2	3	6
Oct 8	6 Fontaine drive	9	9- Foreign Interference	Wires hit by Villeneuve Construction's Truck	8	1	8
Oct-30	Riverside drive	3	3 - Tree Contact	Beaver a cut tree that fell on powerline	12	1.5	18
					6814		3096.5

5.3.Appendix C

Capital program details and explanations

HPDC	**Plant Capital for 2010**			
	Amounts are in dollars			
Category	**Description**	**Plan**	**Actual**	**Variance**
System Access				
	no projects	$0	$0	$0
System Renewal				
	1830/1835 - Distribution Overhead - Replace Poles	n/a	$4,782	
	1845 - U/G conductors and devices - Install new base	n/a	$2,690	
	1850 - Line Transformers - Replace transformer	n/a	$10,782	
	Total	$53,300	$18,254	$35,046
System Service				
	no projects	$30,300	0	$30,300
General Plant				
	1915 - Office Furniture Equipment -	n/a	$5,236	
	Total	$67,550	$5,236	$62,314
	Total Capital	$151,150	$23,490	$127,660

There are no material projects that were completed. See 5.3.3 [the last three paragraphs] for an explanation of the large underspending variances in the capital categories.

HPDC	Plant Capital for 2011			
	Amounts are in dollars			
Category	**Description**	**Plan**	**Actual**	**Variance**
System Access				
	no projects	$0	$0	$0
System Renewal				
	1830/1835 - Distribution Overhead - Replace Poles	n/a	$7,571	
	1845 - U/G conductors and devices - Install new base	n/a	$484	
	1850 - Line Transformers - Replace transformer	n/a	$5,806	
	Total	$58,499	$13,861	$44,638
System Service				
	1860 - Meters - New meters	$5,000	$5,338	-$338
General Plant				
	1930 - Transportation - New boom insert installed on bucket truck T95-1	n/a	$25,129	
	1940 - Tools & Equipment - Pressure washer	n/a	$1,651	
	Total	$205,500	$25,129	$180,371
	Total Capital	$268,999	$44,328	$224,671

There are no material projects that were completed. See 5.3.3 [the last three paragraphs] for an explanation of the large underspending variances in the capital categories. In 2011 General Plant there was the intention to purchase a new bucket truck but only the boom insert was installed.

HPDC	Plant Capital for 2012			
	Amounts are in dollars			
Category	**Description**	**Plan**	**Actual**	**Variance**
System Access				
	no projects	$0	$0	$0
System Renewal				
	1830/1835 - Distribution Overhead - Replace Poles & load brake switch	n/a	$22,120	
	1845 - U/G conductors and devices - Install new base	n/a	$6	
	Total	$58,001	$22,126	$35,875
System Service				
	1855 - Services	n/a	$142	
	1860 - Meters - New PT, CT transformers for meters	n/a	$197	
	Total	$2,500	$339	$2,161
General Plant				
	1908 - Building & Fixtures - New overhead door	n/a	$13,597	
	1908 - Building & Fixtures - New sidewalk and pavement	n/a	$4,294	
	1925 - Computer Software - Billing software upgrade	n/a	$5,795	
	1930 - Transportation - New Bucket & Boom truck	n/a	$218,139	
	Total	$67,000	$241,825	-$174,825
	Total Capital	$127,501	$264,290	-$138,950

The only activity that exceeds the materiality threshold is the General Plant item, the purchase of a bucket truck to replace a unit that was purchased in 1986 and was at end of life. The unit was budgeted in 2011 but only the aerial device was received in 2011. The truck, body and the aerial device mounting etc. was done in 2012. There was no budget transfer or carryover set up. However, in 2011 there was an under expenditure of $180,371 and in 2012 there was an over expenditure of $174,825 so the projects in the general plant category were completed $5546 under budget when the two years are taken together.

Bucket Truck Justification:

The original truck, cab and chassis, was purchased in 1986 and an existing aerial device, which was purchased in 1973, was fitted to the 1986 cab and chassis. In about 2002 the aerial device was refurbished to extend its life. Both the cab and chassis and the aerial device were replaced in 2012. Thus the cab and chassis was 26 years old and the aerial device was 39 years old.

The cost for the replacement was:

$ 25,129	in 2011
$218,139	in 2012
$243,268	total cost

The fact that the truck worked successfully for 26 years and aerial device, a 1973 Pelican, worked for 39 years demonstrates that the equipment was well maintained and cared for. In some utilities the planning rule of thumb is that the cab and chassis last for 7 years and the aerial device lasts 14 years. Clearly, for HPDC this has not been the practice. Some reasons for this may include that because HPDC has a relatively small service area the amount of driving is lower and the winter conditions for corrosion may be different. However, these assets eventually arrive at an economic and functional end of life situation.

The economic end of life considerations that lead to the replacement of the vehicle was the major rust and corrosion to the cab and chassis

In addition, the aerial device was not adequate for the job. The lift capacity of the Pelican aerial device was small, essentially a person and some tools, and with any material like switches etc. it was not able to provide sufficient lift. More material handling capability was required. In addition the unit was only a 36 foot aerial device and line staff would sometimes need to take unsafe positions, like standing on the edge of the bucket, to be able to reach beyond the device limitations to complete their work. The current unit has material handling capability and is a 47 foot aerial device. So it overcomes both the limitations of the old unit.

This new unit improves the ability to reach fuses and switches or make repairs with the added reach and lifting capacity. This improves outage response capability which in turn can help reduce customer interruption durations.

HPDC	**Plant Capital for 2013**			
	Amounts are in dollars			
Category	**Description**	**Plan**	**Actual**	**Variance**
System Access				
	no projects	$0	$0	$0
System Renewal				
	1830/1835 - Distribution Overhead - Replace Poles	n/a	$9,735	
	1845 - U/G conductors and devices - Install new base	n/a	$10,036	
	Total	$58,486	$19,771	-$38,715
System Service				
	1860 - Meters - New polyphase meters	n/a	$7,258	
	Total	$2,500	$7,258	$4,758
General Plant				
	1915 - Office Furniture Equipment - New desktops	n/a	$3,732	
	1930 - Transportation - New pickup	n/a	$28,201	
	Total	$44,250	$31,933	-$12,317
	Total Capital	$105,236	$58,962	-$46,274

There are no material projects that were completed. See 5.3.3 [the last three paragraphs] for an explanation of the large underspending variances in the capital categories.

HPDC	Plant Capital for 2014			
	Amounts are in dollars			
Category	**Description**	**Plan**	**Forecast**	**Variance**
System Access				
	Lecours Motor Sales		$8,000	-$8,000
	Mattawishkwia Solar Park		$5,000	-$5,000
	Pepco		$10,000	-$10,000
	New construction/service		$10,000	-$10,000
		$0	$33,000	-$33,000
System Renewal				
	1830 - Distribution Overhead - Poles	$12,464	$24,181	$11,717
	1835 - Distribution Overhead - O/C	$13,750	$30,862	$17,112
	1845 - U/G conductors and devices	$10,161	$4,377	-$5,784
	1850 - Line Transformers	$11,120	$5,324	-$5,796
	Total	$47,495	$64,743	$17,248
System Service				
	1855 - Services	$0	$298	$298
	1860 - Meters	$0	$1,765	$1,765
	Total	$0	$2,063	-$473
General Plant				
	1908 - Building & Fixtures - New exterior siding, insulation, windows & doors	$70,000	$57,228	-$12,772
	1915 - Office Furniture Equipment	$2,500	$2,855	$355
	1920 - Computer Equipment Hardware	$11,250	$10,153	-$1,097
	1925 - Computer Software	$11,500	$5,351	-$6,150
	1930 - Transportation	$0	$403	$403
	1940 - Tools & Equipment	$8,450	$4,481	-$3,969
	Total	$103,700	$80,469	-$23,231
	Total Capital		$180,274	
	Contributed Capital		$33,000	
	Net Capital	$151,195	$147,274	-$3,921

For 2014 there are no distribution plant capital projects that exceed the materiality threshold. Information is presented on the System Access work that is carried out. In the past this was not available and not reported since it was all contributed capital. In 2014 HPDC is recording this work and recording the capital contributions as indicated in the Chapter 5 filing requirements. For 2015

and moving forward HPDC will be budgeting for the projects anticipated and reporting the actual cost as well as any capital contributions.

A material expenditure was made in the General plant category on the Building assets. The justification for this project is given as follows.

2014 Building modifications - Service Centre

The building was constructed in 1958 by Ontario Hydro. It was purchased by Hearst Public Utilities Commission in 1979. Windows and doors were replaced in 1993, a cold storage addition was constructed in 1995 and as well as re-roofing in 2009.

The facility is used to park the line vehicles inside so that they are clear of snow and ice when starting the workday. The facility is also the meter shop, warehouse for revenue meters, tools, plant consumables like fuse links, connectors etc., the office for the lead hand, and the safety training area for line staff. Because of the multiple uses and because of the computers and other equipment stored and used there, the temperature needs to be kept reasonable for working during the daytime.

The facility had a lot of air leaks which made it drafty and resulted in high heating bills. The facility is electrically heated.

Consumption before renovations and the corresponding Climate Canada “heating degree days” (HDD) information (http://climate.weather.gc.ca/prods_servs/cdn_climate_summary_e.html using the “KAPUSKASING A” weather station information) was:

Jan 2010 – 12,086 kWh, HDD-979.5
Jan 2011 – 13,401 kWh, HDD -1145
Jan 2012 – 12,812 kWh, HDD -992.8
Jan 2013 – 13,566 kWh, HDD -1072.1
Jan 2014 – 14,189 kWh; HDD -1163

After renovations it was:

Jan (very cold month) 2015 – 10,727 kWh; HDD -1139.3

The Jan 2015 energy consumption is about a 20% energy saving over the Jan 2011 consumption which has the closest HDD value.

Basically, due to the fast rising cost of electricity, the cost is still higher in 2015 than in 2010 but the consumption went down significantly. The estimated energy saving is over 15,000 kWh per year which at current electric power rates amounts to approximately $1900 per year.

The modifications consisted of replacing all the doors and windows with new energy efficient units sealed in place to prevent air leaks. There was 1.5 inches of ISO type rigid insulation panels installed on the outside of the existing outside walls which was then covered with aluminium siding. Also, attic insulation was added and overhead garage door sills were replaced. This further insulated the building and sealed it against air leaks.

The actual cost of this work was $54,363. At the current price of power this would result in a payback of about 29 years. With increasing energy costs the payback period would be shorter.

In addition to the actual savings in heating costs, this project also has a positive impact on the environment by reducing the energy use. Doing this project thus also added credibility to the energy conservation message by HPDC within this community.

Pictures of the warehouse can be found in Appendix F.

HPDC	Plant Capital for 2015	
Category	**Description**	**Plan**
System Access		
	New construction/service	$11,000
	Total	$11,000
System Renewal		
	1830 - Distribution Overhead - Replace Poles (20)	$70,000
	1835 - Distribution Overhead - Overhead Conduits	$5,000
	1845 - U/G conductors and devices - Install new base	$5,431
	1850 - Line Transformers - Replace transformer	$6,017
	Total	$86,448
System Service		
	1860 - Meters - New meters	$2,625
	1835 - Overhead Conductors & Devices - Replace porcelain surge arrestors	$13,000
	1835 - Overhead Conductors & Devices - New solid blade switch	$3,000
	Total	$18,625
General Plant		
	1908 - Building & Fixtures - New natural gas furnace + Building sign	$7,500
	1915 - Office Furniture Equipment - New phone system	$2,500
	1920 - Computer Equipment Hardware - New desktop at warehouse (3,000$) + New laser printer for billing (7,000$)	$10,000
	1925 - Computer Software - GIS software, billing software upgrades	$5,000
	1930 - Transportation - New pickup	$28,000
	1940 - Tools & Equipment - New Locator	$7,000
	Total	$60,000
	Total Capital	$176,073
	Contributed Capital	$11,000
	Net Capital	$165,073

The pole replacement program is the only project that exceeds the materiality threshold. The justification for this program is in Appendix D.

The purchase of a new pickup truck in the General Plant category is to replace a truck purchased in 2007. This unit is very rusted and in need of considerable maintenance.

HPDC	Plant Capital for 2016	
Category	**Description**	**Plan**
System Access		
	New construction/service	$12,000
	Total	$12,000
System Renewal		
	1830 - Distribution Overhead - Replace Poles (20)	$73,500
	1835 - Distribution Overhead - Overhead Conduits	$5,250
	1845 - U/G conductors and devices - Install new base	$5,702
	1850 - Line Transformers - Replace transformer	$6,318
	Total	$90,771
System Service		
	1860 - Meters - New meters	$2,756
	1835 - Overhead Conductors & Devices - Replace porcelain surge arrestors	$15,000
	1835 - Overhead Conductors & Devices - New solid blade switch	$3,120
	Total	$20,876
General Plant		
	1908 - Building & Fixtures - Warehouse interior renovations (Interior flooring, walls & doors)	$20,000
	1925 - Computer Software - GIS & billing software upgrades	$5,200
	1930 - Transportation - misc. repairs	$20,000
	1940 - Tools & Equipment - New tools	$2,500
	Total	$47,700
	Total Capital	$171,347
	Contributed Capital	$12,000
	Net Capital	$159,347

The pole replacement program is the only project that exceeds the materiality threshold. The justification for this program is in Appendix D.

HPDC	Plant Capital for 2017	
Category	**Description**	**Plan**
System Access		
	New construction/service	$13,000
	Total	$13,000
System Renewal		
	1830 - Distribution Overhead - Replace Poles (20)	$77,175
	1835 - Distribution Overhead - Overhead Conduits	$5,513
	1845 - U/G conductors and devices - Install new base	$5,988
	1850 - Line Transformers - Replace transformer	$6,634
	Total	$95,309
System Service		
	1860 - Meters - New meters	$2,894
	1835 - Overhead Conductors & Devices - New solid blade switch	$3,245
	Total	$6,139
General Plant		
	1908 - Building & Fixtures - New desk and cabinets at warehouse	$10,000
	1925 - Computer Software - GIS & billing software upgrades	$5,408
	1930 - Transportation - misc. repairs	$21,000
	1940 - Tools & Equipment - New tools	$2,600
	Total	$39,008
	Total Capital	$153,456
	Contributed Capital	$13,000
	Net Capital	$140,456

The pole replacement program is the only project that exceeds the materiality threshold. The justification for this program is in Appendix D.

HPDC	Plant Capital for 2018	
Category	**Description**	**Plan**
System Access		
	New construction/service	$14,000
	Total	$14,000
System Renewal		
	1830 - Distribution Overhead - Replace Poles (20)	$81,034
	1835 - Distribution Overhead - Overhead Conduits	$5,788
	1845 - U/G conductors and devices - Install new base	$6,287
	1850 - Line Transformers - Replace transformer	$6,966
	Total	$100,074
System Service		
	1860 - Meters - New meters	$3,039
	1835 - Overhead Conductors & Devices - New solid blade switch	$3,375
	Total	$6,413
General Plant		
	1915 - Office Furniture Equipment - New folding machine	$18,000
	1925 - Computer Software - GIS & billing software upgrades	$5,624
	1930 - Transportation - misc. repairs	$25,000
	1940 - Tools & Equipment - New tools	$2,704
	Total	$51,328
	Total Capital	$171,816
	Contributed Capital	$14,000
	Net Capital	$157,816

The pole replacement program is the only project that exceeds the materiality threshold. The justification for this program is in Appendix D.

HPDC	Plant Capital for 2019	
Category	**Description**	**Plan**
System Access		
	New construction/service	$15,000
	Total	$15,000
System Renewal		
	1830 - Distribution Overhead - Replace Poles (20)	$85,085
	1835 - Distribution Overhead - Overhead Conduits	$6,078
	1845 - U/G conductors and devices - Install new base	$6,601
	1850 - Line Transformers - Replace transformer	$7,314
	Total	$105,078
System Service		
	1860 - Meters - New meters	$3,191
	1835 - Overhead Conductors & Devices - New solid blade switch	$3,510
	Total	$6,700
General Plant		
	1908 - Building & Fixtures - Safety fence repairs	$20,000
	1920 - Computer Equipment Hardware - 3 new desktops for offices	$12,000
	1925 - Computer Software - GIS & billing software upgrades	$5,849
	1930 - Transportation - misc. repairs	$26,250
	1940 - Tools & Equipment - New tools	$2,812
	Total	$66,911
	Total Capital	$193,690
	Contributed Capital	$15,000
	Net Capital	$178,690

The pole replacement program is the only project that exceeds the materiality threshold. The justification for this program is in Appendix D.

5.4.Appendix D

Justification for the Pole Replacement program.

Justification for the Pole Replacement program

HPDC has replaced poles that were at end of life in previous years. An issue that was not clear was the criteria for the decision to replace a pole.

HPDC has more than 1,000 poles in service that were installed in the 1950's and 1960's. The photographs below are a few of the photographs taken at random to illustrate the condition of the poles. As a result the pole assessment detailed in Appendix E was developed so that an objective assessment could be carried out that was independent of the "opinion" of any one person but based on the physical features that were observable. The assessment process was tried out by the Lead hand and the Line crew members individually and there was close agreement on the rating of the poles after the initial training on the approach to the assessment. The assessment process was accepted by all as a valid approach and there was confidence by each person that they were performing the assessments correctly and that each of them produced equally valid assessments. The people trained to do the assessments between the three of them visited and assessed all the poles with 35 or more years in service.

The assessment produced a single measure of the condition of the pole condition and HPDC set a level of 17 and lower where the poles would be replaced. This resulted in 126 poles that needed to be replaced. It was also decided that only the poles that needed to be replaced per the assessment would be included in this pole replacement program and that total street rebuilds would not be done. However any open wire services from a replaced pole would be upgraded to the current standard triplex service. In several cases consecutive poles need to be replaced. In these sections the secondary bus is also converted from an open wire to a triplex bus per current standards. Otherwise the replacement is like for like.

The pole replacement is needed because of the condition of the poles. Maintenance will not restore strength to these poles and any maintenance treatment to slow the deterioration would be costly and ineffective when compared to the replacement option.

The timing of the project is such that it can be completed over several years with no increased costs to complete the program other than the changing costs of material and labour in each year of the program. HPDC estimates that this escalation is 5% per year and the annual projections reflect this though the actual work to be performed remains constant. HPDC decided to complete the pole replacement program over a 5 year period to achieve workload and capital expenditure smoothing thus minimizing customer rate increase impacts while still addressing the work that needs to be done at a reasonable pace.

If the current work were not carried out there would be a continued deterioration in pole strength and this would most likely result in single or grouped pole failures in adverse weather situations that would result in increased Operating and Maintenance costs as well as long power restoration times, likely to many customers. By taking the current approach HPDC is addressing the need for asset replacement on a planned basis prior to in-service failure, which is the lowest cost method, and doing it at a modest pace to ease the customer rate impact and maintains current system reliability performance.

Photographs:

An example of Shell Rot

Pole deforming due to reduced fiber strength and side force loading

An example of wood fiber deterioration

An example of wood deterioration

An “old” pole- installed in 1951

An example of long deep cracks

5.5.Appendix E

Pole Inspection Process – Poles in Service More Than 35 Years

Pole Condition Assessment

Rating system for pole condition:

Several factors impact the condition of a pole and the assessment of its capabilities and useful life expectancy:

Some of these factors are:

- Age of the pole
- Surface deterioration or shell rot
- Longitudinal cracks along the pole
    - Characterized by depth of the crack [accessible from the ground]
    - Characterized by the length of the crack
    - Characterized by the number of cracks in the pole
    - Characterized by the presence of rot in the crack
- Ground line deterioration of the pole to 6 inches below grade
    - Check with a sharp object or screwdriver to what distance the wood is soft from deterioration. Check in 4 quadrants and get an average depth of penetration.
- Test with a hammer to see if the heart of the pole sounds solid or not.

These factors combine to give an overall rating of the pole.

Hearst Power has decided to use the following factors and rating for each factor:

Age (A):

Rating Value	Criteria or measurements
1	over 50 years old
2	40 to 50 years old
3	30 to 40 years old
4	20 to 30 years old
5	less than 20 years old

(B) Sum of depth of all separate cracks accessible by a person at ground level

Rating Value	Criteria or measurements
1	Greater than 12 inches
2	10 to 12 inches
3	8 to 10 inches
4	4 to 8 inches
5	Less than 4 inches

(C) Length of cracks one inch or more deep- reachable by a person on the ground.

Rating Value	Criteria or measurements
1	More than 50% of the pole height
2	25% to 50% of the pole height
3	10% to 25% of the pole height
4	Less than 10% of the pole height

(D) Number of cracks on the pole that are significant [appear to be deep- 1 inch or more- and wide – ¼ inch or more and visible from the ground if above the secondary level.]

Rating Value	Criteria or measurements
1	More than 10
2	8 to 10
3	6 to 8
4	3 to 6
5	Less than 3

(E) Presence of rot or growth in cracks or spur gaffs

Rating Value	Criteria or measurements
1	Rot / growth is present
2	No rot / growth present

(F) Condition at ground line [at grade]. Take 4 measurements 90 degrees apart. Sum the values of the penetration.

Rating Value	Criteria or measurements
1	More than 12 inches
2	10 to 12 inches
3	8 to 10 inches
4	4 to 8 inches
5	Less than 4 inches

(G) Hammer test no more than 1 foot above ground level and take soundings 90 degrees apart

Rating Value	Criteria or measurements
1	Definite Core deterioration
2	Possible Core deterioration
3	No perceived core deterioration

In each measure a low number is a poorer condition pole.

To come up with a single value each of the factors A to G are weighted equally relative to the other factors. Hence to get an overall assessment of the pole condition, add the rating values of the factors together for each pole. For example the worst score would be A+B+C+D+E+F+G=7 and the best score would be 29.

HPDC used the above criteria and surveyed 1123 poles that have been in service for 35 or more years. The criteria for replacement are a rating of 17 or lower. The lower the rating the poorer the pole condition is. The table below shows the poles that need to be replaced based on the survey and the selection criterion. Note that there is a mixture of single phase and three phase lines and that a significant number of these poles also have transformers mounted on them.

Hearst Power Distribution Company Limited					
Poles to be replaced [with condition assessment 2014]					
Pole #	**Location**	**Height**	**total condition rating**	**Phase**	**Tx**
434	5th St. MOE lift pumphouse	45	17	3	Y
	1300 Prince (in yard)	25	16	NA	N
616	1440 Prince	30	17	NA	N
390	1122 Alexandra	35	17	1	N
223	Edward (west of St-Louis)	45	17	3	Y
232	1124 Edward	45	16	3	N
239	14th & Edward	45	17	3	N
31_1	3rd & Front (north side)	50	14	3	N
176	3rd St.	50	12	3	Y
471	6th St. (between Alexandra & Prince)	40	17	3	N
470	6th St. (between Alexandra & Prince)	40	17	3	N
468	6th St. (between Prince & George)	40	12	3	Y
500	9th St. (Caisse Pop. Park)	40	12	3	N
501	9th St. (Caisse Pop. Park)	40	17	3	Y
513	9th (between Edward & Kitchener)	40	13	3	N
514	9th (Pavillon Notre Dame school driveway)	40	9	3	Y
515	9th & Kitchener	40	14	3	N
519	9th St. (north of bridge)	40	17	3	Y
	10th St. (next to river - OCWA)	40	11	NA	N
1284	Tricept yard	50	17	3	N
1285	Tricept yard	45	17	3	N
	Front St. (CFP weigh scale)	45	17	3	N
1305	Front St.	45	17	3	N
175	3rd & Front (south west)	45	12	3	N
	Front & Hwy 11E. (east side)	35	14	NA	N
	6th & Front St.	40	13	1	N
325	Front St. (PEPCO yard)	35	17	NA	N
324	7th & Front St. (south west)	35	7	NA	N
321	715 Front	40	16	3	n
366	1020 Front (behind Assurance Aubin)	45	16	3	Y
30	Hwy 11 E (OCWA lift station)	55	17	3	Y
90	508 Hwy 11 E	45	17	1	N

Hearst Power Distribution Company Limited					
Poles to be replaced [with condition assessment 2014]					
Pole #	**Location**	**Height**	**total condition rating**	**Phase**	**Tx**
88	518 Hwy 11 E	35	17	1	N
87	518 Hwy 11 E	40	17	1	N
86	Hwy 11 E & Blanchard	40	17	1	Y
85	526 Hwy 11 E	35	16	1	N
84	530 Hwy 11 E	35	15	1	N
44	Mailloux & Tremblay (north west)	45	17	3	N
48	2 Fontaine Dr.	40	12	3	N
	618 Tremblay	30	15	NA	N
142	1 Rouse	25	16	NA	N
110	627 Allen	40	17	1	Y
105	5 Rouse	35	17	1	N
147	Rouse & Veilleux (south east)	35	17	NA	N
149	629 Veilleux	30	17	NA	N
101	620 Veilleux	35	17	NA	N
1356	19 Picard	35	17	1	Y
1345	7 Picard	35	17	1	N
1316	416 Tremblay	40	17	1	N
1320	400 Tremblay	40	14	1	N
1317	413 Tremblay	30	17	NA	N
10016	Airport Rd (2nd from Johnson Lake Rd)	35	16	3	N
10018	Airport Rd (4th from Johnson Lake Rd)	35	16	3	N
	Airport Rd (10th from Johnson Lake Rd)	35	7	3	N
1227	Riverside Dr (river crossing)	40	13	1	N
1238	64 Riverside Dr	35	17	1	N
1239	Riverside Dr	35	17	1	N
1242	84 Riverside Dr	35	16	1	Y
123	Hwy 11E (south side near bridge)	40	17	3	N
1134	222 Hwy 11E	25	16	NA	N
1139	218 Hwy 11E (south side)	55	17	3	N
1126	103 Hwy 11E	40	16	1	Y
1065	Hwy 11E & Lafond Rd (south side of hwy)	55	13	1	N
1013	45 Hwy 11E	25	17	NA	N

Hearst Power Distribution Company Limited					
Poles to be replaced [with condition assessment 2014]					
Pole #	**Location**	**Height**	**total condition rating**	**Phase**	**Tx**
1008	21 Hwy 11E	40	16	1	N
1007	21 Hwy 11E	50	13	1	N
1004	21 Hwy 11E	35	15	NA	N
1000	2 Hwy 11E	30	16	NA	N
1064	Collin Rd (1st south of tracks)	55	14	1	N
1062	Collin Rd (2nd south of tracks)	40	15	1	N
1060	17 Collin Rd	35	16	1	N
1059	Collin Rd	40	17	1	N
1058	Collin Rd	35	14	1	N
1055	Collin Rd	35	15	1	N
1054	Collin Rd	35	17	1	N
1053	Collin Rd	35	17	1	N
1050	Collin Rd	35	15	1	N
1049	Collin Rd	40	14	1	N
1042	1 Bosnick Rd	35	17	1	N
1041	Bosnick Rd & Collin Rd	35	16	1	N
1040	Bosnick Rd	35	16	1	N
1038	21 Bosnick Rd	35	17	1	Y
	37 Bosnick Rd (in yard)	35	17	1	N
1035	Bosnick Rd	35	15	1	N
1034	Bosnick Rd	35	16	1	N
1032	Bosnick Rd	35	16	1	N
1140	P'tite Gaspesie Rd (old Levesque Lumber)	40	16	3	N
1143	P'tite Gaspesie Rd (old Levesque Lumber)	40	16	3	N
1145	P'tite Gaspesie Rd (old Levesque Lumber)	45	17	3	N
1150	P'tite Gaspesie Rd (old Levesque Lumber)	40	17	3	N
1152	P'tite Gaspesie Rd (old Levesque Lumber)	40	16	1	N
1153	15 P'tite Gaspesie Rd (old Levesque Lumber)	35	16	1	Y
1156	14 P'tite Gaspesie Rd (near garage)	35	17	1	N
1157	14 P'tite Gaspesie Rd (near garage)	35	17	1	Y

Hearst Power Distribution Company Limited					
Poles to be replaced [with condition assessment 2014]					
Pole #	**Location**	**Height**	**total condition rating**	**Phase**	**Tx**
1158	29 P'tite Gaspesie Rd (in yard)	35	17	1	Y
1159	P'tite Gaspesie Rd	35	14	1	N
1163	P'tite Gaspesie Rd	35	16	1	N
1170	P'tite Gaspesie Rd	40	15	3	N
698	Girard Dr (2nd to Girard farm)	35	17	1	N
	270 Hwy 583S	35	17	1	N
	270 Hwy 583S	35	15	1	N
896	19 Blais Rd (6th from Hwy 583S)	35	17	1	Y
899	Blais Rd (8th from Hwy 583S)	35	17	1	N
	37 Blais Rd (west of driveway)	35	17	NA	N
904	Blais Rd (13th from Hwy 583S)	35	16	1	N
914	1 Roy Rd	35	16	1	Y
764	McNee	40	17	1	N
781.1	186 McNee	25	16	NA	N
791	213 McNee	35	17	1	Y
801	Cloutier Rd S	35	16	1	N
810	Cloutier Rd S	35	14	1	N
815	Cloutier Rd S	35	17	1	N
818	Cloutier Rd S	35	15	1	N
820	Cloutier Rd S	35	15	1	N
823	Cloutier Rd S	40	16	1	Y
824	Cloutier Rd S (south side of river)	40	15	1	N
825	Cloutier Rd S (north side of river)	40	17	1	N
827	Cloutier Rd S	35	17	1	N
847	Cloutier Rd N	40	14	1	N
861	42 Cloutier Rd N	40	16	1	Y
876	Cloutier Rd N (3 span north of #58)	35	17	1	N
879	97 Cloutier Rd N (west side)	40	14	1	Y
1424	10 Stolz	40	16	1	Y
1447	5 Vandette	40	12	3	Y
1465	1867 Hwy 11W	35	16	NA	N
	54 Morin Rd (dead end at Morin camping)	40	13	1	Y

5.6.Appendix F

Photographs of HDDCL Warehouse Improvements

Front of Warehouse

Before

Front of Warehouse

After

Back of Warehouse

Before

Back of Warehouse

After

Service Quality and Reliability Performance

Ex.2/Tab 7/Sch.1 - Service Quality and Reliability Performance

HPDC records and reports annually the following Service Reliability Indices:

- SAIDI = Total Customer-Hours of Interruptions/Total Customers Served
- SAIFI = Total Customer Interruptions/Total Customers Served
- CAIDI = Total Customer-Hours of Interruptions/Total Customer Interruptions

These indices provide HPDC with annual measures of its service performance that are used for internal benchmarking purposes when making comparisons with other distribution companies (e.g. to better understand the rankings that will support the OEB's Incentive Rate Making Mechanism and Performance Based Regulation). They are reported in accordance with Section 7.3.2 of the OEB's Electricity Distribution Rate Handbook.

Appendix 2-G - Service Reliability Indicators

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2010	2011	2012	2013	2014*	2010	2011	2012	2013	2014*
SAIDI	6.06	2.88	3.02	4.9	1.11	0.64	0.27	2.80	1.25	0.65
SAIFI	3.1	0.95	1.16	2.06	2.45	0.76	0.21	1.03	0.87	0.29

	5 Year Historical Average			
SAIDI		3.594		0.455
SAIFI		1.944		0.632

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

*Up to Oct 31, 2014

Indicator	OEB Minimum Standard	2009	2010	2011	2012	2013
Low Voltage Connections	90.0%					
High Voltage Connections	90.0%					
Telephone Accessibility	65.0%	95.3%	96.7%	95.0%	92.5%	100.0%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Written Response to Enquires	80.0%					
Emergency Urban Response	80.0%					
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%					
Appointment Scheduling	90.0%					
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1