niagara peninsula energy

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March 1, 2011

Delivered by RESS and Courier

Ontario Energy Board
P.O. Box 2319
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2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Re: Niagara Peninsula Energy Inc. Application for 2011 Distribution Rates
Board File Number: EB-2010-0138
Response to Interrogatories – Energy Probe

Dear Ms. Walli:

Please find attached Niagara Peninsula Energy Inc.'s responses to interrogatories on its 2011 Electricity Distribution Cost of Service Rate Application. Two hard copies will follow by courier.

If further information is required, please contact Suzanne Wilson, Vice-President Finance at 905-353-6004 or Suzanne.Wilson@npei.ca.

Yours truly,

Brian Wilkie
President & CEO

Cc: Intervenors of Record

NIAGARA PENINSULA ENERGY INC. RESPONSES
2011 RATES REBASING CASE
EB-2010-0138

ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

Interrogatory #1

Ref: Exhibit 1, page 13

Please provide the asset condition study and Asset Management Plan prepared by Kinetics. If this is still not available, when does NPEI expect it will be available?

Response

The Asset Management Plan which includes the Asset Condition Assessment study was submitted to the Ontario Energy Board on February 14th, 2011.

Please see Appendix A.

Interrogatory #2

Ref: Exhibit 1, page 15

Has NPEI completed an updated depreciation study for the new IFRS componentization rules? If so, please file the study and indicate what impact it would have on the depreciation expense in the 2011 test year if it were to be used in place of the current depreciation rates.

Response

NPEI has not commenced or completed an updated depreciation study for the new IFRS componentization rules. NPEI was waiting for the asset condition assessment study from Kinetrics. NPEI will commence this study in 2011.

Interrogatory #3

Ref: Exhibit 1, page 48

Are there any costs included in the 2011 revenue requirement associated with the Board of Directors of either Niagara Falls Holding Corporation or Peninsula West Power Inc.? If yes, please quantify these amounts and indicate what they related to.

Response

There are no costs associated with the Board of Directors of either Niagara Falls Hydro Holding Corporation or Peninsula West Power Inc. included in the 2011 revenue requirement.

Interrogatory #4

Ref: Exhibit 2, page 27, Table 2-7

a) **Please update Table 2-7 to reflect actual capital expenditures for 2010. If actual data for 2010 is not yet available, please update the 2010 bridge year forecast to reflect the most recent year-to-date actuals available, along with a projection for the remainder of the year.**

b) **Please explain the negative figures shown for account 1815 in 2005 and 2006.**

Response

a) The following table is an updated version of Table 2-7 that includes actual capital expenditures for 2010, based on the most up-to-date information available as at February 22, 2011.

Table 2.7

Summary of Capital Additions by Year - Updated to Include 2010 Actuals

USoA	Description	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Forecast	2010 Actual	2011 Test
1806	Land Rights	159,411	89,984	30,031	-	-	-		-
1808	Buildings and Fixtures	0	10,204	18,296	-	-	-		-
1815	Transformer Station Equipment	(301,622)	(218,750)	-	-	-	-	43,487	-
1820	Distribution Station Equipment	9,351	28,197	-	-	276,481	185,185	476,632	462,963
1830	Poles, Towers and Fixtures	635,300	1,639,570	2,901,140	1,856,704	1,982,247	2,860,613	1,960,627	2,482,838
1835	Overhead Conductors and Devices	850,779	1,487,310	2,527,454	2,865,321	2,060,811	1,231,327	1,528,973	972,176
1840	Underground Conduit	2,312,448	928,142	660,180	650,997	471,148	1,175,040	1,123,895	1,369,289
1845	Underground Conductors and Devices	1,803,836	2,293,204	1,978,131	1,738,623	2,200,580	1,723,794	1,943,735	1,572,596
1850	Line Transformers	1,581,156	1,378,952	2,048,116	1,189,608	1,222,298	1,384,010	1,075,315	1,284,894
1855	Services	547,476	567,794	701,366	342,962	324,654	486,923	394,289	499,935
1860	Meters	480,925	352,242	334,706	200,905	258,429	4,369,541	4,374,664	185,185
1905	Land	229,465	-	-	-	279,505	-		-
1908	Buildings and Fixtures	50,705	45,388	430,422	4,146,632	2,385,705	188,557	67,188	-
1915	Office Furniture and Equipment	65,635	73,858	18,181	174,930	161,652	70,564	35,091	92,593
1920	Computer Equipment - Hardware	183,075	119,227	101,762	525,453	185,269	273,500	257,960	291,898
1925	Computer Software	643,900	213,418	62,326	208,496	369,215	278,954	250,022	182,870
1930	Transportation Equipment	214,249	515,857	227,707	576,543	589,462	824,149	869,037	462,963
1935	Stores Equipment	(0)	-	-	-	18,090	18,900	26,336	-
1940	Tools, Shop and Garage Equipment	154,514	48,599	60,052	38,218	49,335	94,342	94,973	92,593
1945	Measurement and Testing Equipment	38,940	71,867	-	6,083	12,160	4,690	5,700	-
1955	Communication Equipment	(0)	-	1,866	28,326	45,272	2,843	9,662	-
1960	Miscellaneous Equipment	0	-	-	24,228	5,586	5,049	5,049	-
1995	Contributions and Grants	(3,920,772)	(1,354,458)	(1,683,128)	(1,712,904)	(1,197,961)	(1,200,000)	(1,160,428)	(850,000)
	Total Capital Additions	5,738,770	8,290,606	10,418,607	12,861,125	11,699,938	13,977,982	13,382,205	9,102,793
	Dollar increase (decrease)		2,551,836	2,128,000	2,442,518	(1,161,187)	2,278,044	(595,776)	(4,279,413)
	Percent increase (decrease)		44.5%	25.7%	23.4%	-9.0%	19.5%	-4.3%	-32.0%

Total 2010 Capital Additions per Energy Probe IR 4	13,382,205
Total 2010 Capital Additions per SEC IR 10	13,136,861
Difference	245,344

NPEI notes that the total fixed asset additions for 2010, as per the above table, is $13,382,205. In response to the School Energy Coalition (“SEC”) Interrogatory #10, NPEI indicated that the 2010 actual additions were $13,136,861. The difference of $245,344 relates to 2010 lot rebates that were entered into NPEI’s accounting system on February 22, 2011, after the SEC response had been prepared.

b) The negative figures shown for additions to account 1815 in 2005 and 2006 relate to Scientific Research and Experimental Development (“SR&ED”) tax credits. Niagara Falls Hydro’s expenditures for the Kalar Transformer Station qualified for the SR&ED tax credit, which was credited to account 1815 when received. The credit of ($479,652) received in 2005 relates to qualifying 2003 expenditures. The credit of ($218,750) received in 2006 relates to qualifying 2004 expenditures.

Interrogatory #5

Ref: Exhibit 2, page 4, Table 2-10

a) **Please explain why the disposal shown for accumulated depreciation is greater than the disposal shown for gross additions for account 1915 in Table 2-10 for 2008.**

b) **Please explain why there is no disposal shown for accumulated depreciation in account 1955 in Table 2-10 for 2008.**

Response

a) The continuity schedule for 2007 sums the RRR Trial Balances of the former Peninsula West Utilities and the former Niagara Falls Hydro. Instead of adjusting the opening 2008 balances (which currently link to the 2007 ending values) NPEI made reallocation adjustments on the 2008 continuity schedule in order to arrive at the ending 2008 balances. The total additions for 2008 of $12,861,125 tie to the 2008 audited financial statements.

The total disposal on cost = $1,177,648 and the total disposal on accumulated depreciation was 1,180,297. The difference is $2,649 which related to Land Rights. The former Peninsula West Utilities combined accumulated depreciation of account 1915 and account 1955 in one account.

Account 1915 Disposal Cost	104,959
Account 1995 Disposal Cost	34,501
Total	139,460
Account 1915 Accumulated Depreciation Disposal	(139,460)

The net impact is zero.

b) The accumulated depreciation in account 1955 was included in account 1915 by the former Peninsula West Utilities and therefore the adjustment need to be taken from its original source on the continuity schedule.

Interrogatory #6

Ref: Exhibit 2, page 42, Table 2-12

a) **Please provide a version of Table 2-12 that reflects a full year of depreciation for assets added in 2010 similar to the methodology used in 2006 through 2009, rather than the half-year methodology.**

b) **Please provide an updated Table 2-12 to reflect actual data for 2010, or if not yet available, to reflect the most recent year-to-date information available, along with a projection for the remainder of the year. Please calculate the additions to accumulated depreciation based on the full year methodology as requested in part (a) above.**

Response

a) The 2010 fixed asset continuity schedule below reflects a full year of depreciation for assets added in 2010.

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2010

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	507,274	0	0	507,274	0	0	0	0	507,274
1806	Land Rights	1,598,170	0	0	1,598,170	633,336	56,850	0	690,185	907,984
1808	Buildings and Fixtures	111,638	0	0	111,638	91,869	9,661	0	101,530	10,108
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Prima	6,558,514	0	0	6,558,514	757,613	144,978	0	902,591	5,655,923
1820	Distribution Station Equipment - Normally Primar	4,507,465	185,185	0	4,692,651	2,809,726	133,277	0	2,943,003	1,749,648
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	28,665,012	2,860,613	0	31,525,625	14,461,696	889,782	0	15,351,478	16,174,146
1835	Overhead Conductors and Devices	31,395,023	1,231,327	0	32,626,350	15,490,537	1,192,512	0	16,683,049	15,943,301
1840	Underground Conduit	10,367,640	1,175,040	0	11,542,680	3,142,094	195,965	0	3,338,059	8,204,622
1845	Underground Conductors and Devices	54,396,854	1,723,794	0	56,120,648	28,314,738	2,342,098	0	30,656,836	25,463,813
1850	Line Transformers	31,103,686	1,384,010	0	32,487,696	15,981,171	1,151,174	0	17,132,345	15,355,351
1855	Services	3,459,629	486,923	0	3,946,552	626,179	157,860	0	784,039	3,162,513
1860	Meters	6,677,338	4,369,541	3,163,008	7,883,872	3,921,874	319,253	2,204,477	2,036,650	5,847,221
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	508,970	0	0	508,970	0	0	0	0	508,970
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	12,391,184	188,557	0	12,579,740	1,817,234	212,204	0	2,029,438	10,550,302
1910	Leasehold Improvements	120,252	0	0	120,252	120,252	0	0	120,252	(0)
1915	Office Furniture and Equipment	1,107,299	70,564	0	1,177,863	628,664	78,052	0	706,717	471,147
1920	Computer Equipment - Hardware	2,624,840	273,500	0	2,898,340	1,953,498	274,708	0	2,228,206	670,134
1925	Computer Software	1,920,006	278,954	0	2,198,960	1,735,390	418,760	0	2,154,150	44,810
1930	Transportation Equipment	5,484,897	824,149	0	6,309,047	3,706,634	449,904	0	4,156,538	2,152,509
1935	Stores Equipment	200,261	18,900	0	219,161	182,660	4,454	0	187,114	32,047
1940	Tools, Shop and Garage Equipment	1,566,110	94,342	0	1,660,452	1,257,226	67,291	0	1,324,517	335,935
1945	Measurement and Testing Equipment	183,146	4,690	0	187,835	133,421	28,484	0	161,905	25,931
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	158,934	2,843	0	161,777	92,379	19,222	0	111,601	50,176
1960	Miscellaneous Equipment	67,903	5,049	0	72,952	46,643	6,952	0	53,595	19,357
1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	128,961	0	0	128,961	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(16,320,649)	(1,200,000)	0	(17,520,649)	(3,370,553)	(677,746)	0	(4,048,298)	(13,472,350)
2005	Property under Capital Lease	143,036	0	0	143,036	0	0	0	0	143,036
	Total before Work in Process	**189,633,833**	**13,977,982**	**3,163,008**	**200,448,806**	**94,663,241**	**7,475,696**	**2,204,477**	**99,934,461**	**100,514,346**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**189,633,833**	**13,977,982**	**3,163,008**	**200,448,806**	**94,663,241**	**7,475,696**	**2,204,477**	**99,934,461**	**100,514,346**

		Less: Fully Allocated Depreciation	
1925	Transportation	Transportation	0
1930	Stores Equipment	Communication	
		Net Depreciation	7,475,696

The following table summarizes the effects of changing to a full year of depreciation in 2010:

2011 Test Year	Per Application (Half Year Rule applied in 2010)	Per EP IR 6a (Full Year of Depreciation taken in 2010)	Difference
2010 Depreciation Expense	7,000,940	7,475,696	474,756
2011 Opening Net Book Value	100,989,102	100,514,346	(474,756)
2011 Depreciation Expense	7,143,688	7,143,688	-
2011 Closing Net Book Value	102,948,206	102,473,450	(474,756)
2011 Rate Base	119,144,943	118,670,187	(474,756)
2011 Deemed Interest Expense	4,340,146	4,322,851	(17,294)
2011 Deemed Return on Equity	4,694,311	4,675,605	(18,705)
2011 Revenue Deficiency (before tax)	2,451,313	2,419,960	(31,353)
2011 Revenue Deficiency (grossed up)	3,378,275	3,334,910	(43,364)
2011 Service Revenue Requirement	32,421,330	32,377,965	(43,364)

b) The 2010 fixed asset continuity schedule below reflects a full year of depreciation for assets added in 2010 and is based on NPEI’s actual 2010 additions, based on the most up-to-date information available as at February 22, 2011.

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2010

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	507,274	0	0	507,274	0	0	0	0	507,274
1806	Land Rights	1,598,170	0	0	1,598,170	633,336	56,850	0	690,185	907,984
1808	Buildings and Fixtures	111,638	0	0	111,638	91,869	9,661	0	101,530	10,108
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Prima	6,558,514	43,487	0	6,602,001	757,613	146,065	0	903,678	5,698,323
1820	Distribution Station Equipment - Normally Primar	4,507,465	476,632	0	4,984,097	2,809,726	144,935	0	2,954,661	2,029,436
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	28,665,012	1,960,627	0	30,625,639	14,461,696	853,783	0	15,315,479	15,310,160
1835	Overhead Conductors and Devices	31,395,023	1,528,973	0	32,923,995	15,490,537	1,204,418	0	16,694,955	16,229,040
1840	Underground Conduit	10,367,640	1,123,895	0	11,491,536	3,142,094	193,919	0	3,336,013	8,155,523
1845	Underground Conductors and Devices	54,396,854	1,943,735	0	56,340,589	28,314,738	2,350,896	0	30,665,633	25,674,956
1850	Line Transformers	31,103,686	1,075,315	0	32,179,000	15,981,171	1,138,826	0	17,119,997	15,059,003
1855	Services	3,459,629	394,289	0	3,853,918	626,179	154,154	0	780,333	3,073,584
1860	Meters	6,677,338	4,374,664	3,163,008	7,888,994	3,921,874	319,459	2,204,477	2,036,856	5,852,139
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	508,970	0	0	508,970	0	0	0	0	508,970
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	12,391,184	67,188	0	12,458,371	1,817,234	210,181	0	2,027,415	10,430,956
1910	Leasehold Improvements	120,252	0	0	120,252	120,252	0	0	120,252	(0)
1915	Office Furniture and Equipment	1,107,299	35,091	0	1,142,390	628,664	74,505	0	703,169	439,221
1920	Computer Equipment - Hardware	2,624,840	257,960	0	2,882,799	1,953,498	271,600	0	2,225,098	657,701
1925	Computer Software	1,920,006	250,022	0	2,170,029	1,735,390	389,828	0	2,125,218	44,810
1930	Transportation Equipment	5,484,897	869,037	0	6,353,934	3,706,634	455,515	0	4,162,149	2,191,786
1935	Stores Equipment	200,261	26,336	0	226,597	182,660	5,198	0	187,858	38,739
1940	Tools, Shop and Garage Equipment	1,566,110	94,973	0	1,661,083	1,257,226	67,354	0	1,324,580	336,503
1945	Measurement and Testing Equipment	183,146	5,700	0	188,846	133,421	28,686	0	162,107	26,739
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	158,934	9,662	0	168,596	92,379	20,926	0	113,305	55,291
1960	Miscellaneous Equipment	67,903	5,049	0	72,952	46,643	6,952	0	53,595	19,356
1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	128,961	0	0	128,961	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(16,320,649)	(1,160,428)	0	(17,481,077)	(3,370,553)	(676,163)	0	(4,046,716)	(13,434,361)
2005	Property under Capital Lease	143,036		0	143,036	0	0	0	0	143,036
	Total before Work in Process	**189,633,833**	**13,382,205**	**3,163,008**	**199,853,030**	**94,663,241**	**7,427,549**	**2,204,477**	**99,886,313**	**99,966,717**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**189,633,833**	**13,382,205**	**3,163,008**	**199,853,030**	**94,663,241**	**7,427,549**	**2,204,477**	**99,886,313**	**99,966,717**
						Less: Fully Allocated Depreciation				
1925	Transportation					Transportation	0			
1930	Stores Equipment					Communication				
						Net Depreciation	7,427,549			

The following table summarizes the impact of using 2010 actual fixed asset additions:

2011 Test Year	Per EP IR 6a (2010 Forecast, Full Year of Depreciation taken in 2010)	Per EP IR 6b (2010 Actual, Full Year of Depreciation taken in 2010)	Difference
2010 Depreciation Expense	7,475,696	7,427,549	(48,147)
2011 Opening Net Book Value	100,514,346	99,966,717	(547,629)
2011 Depreciation Expense	7,143,688	7,095,541	(48,148)
2011 Closing Net Book Value	102,473,450	101,973,969	(499,481)
2011 Rate Base	118,670,187	118,146,632	(523,555)
2011 Deemed Interest Expense	4,322,851	4,303,780	(19,072)
2011 Deemed Return on Equity	4,675,605	4,654,977	(20,628)
2011 Revenue Deficiency (before tax)	2,419,960	2,352,301	(67,659)
2011 Revenue Deficiency (grossed up)	3,334,910	3,241,556	(93,354)
2011 Service Revenue Requirement	32,377,965	32,284,611	(93,354)

Interrogatory #7

Ref: Exhibit 2, page 14 and Tables 2-8 through 2-11

At page 14 it is indicated that prior to 2010 full amortization was recorded in the year of acquisition and that the amortization rate used for computer software was 100%.

a) **In light of the above, please explain why the figures shown for computer software in Tables 2-8 through 2011 reflect a net book value greater than $0 for computer software. In particular, if acquisitions are fully amortized in the first year, why is there an ongoing positive net book value?**

b) **Please explain why the depreciation shown for 2009 is less than the additions to this account, given the accounting policy detailed above.**

Response

a) NPEI uses a stand alone fixed asset sub-ledger software program called WORTHIT which is used to record additions for Accounts 1915 to 1980. This sub-ledger records depreciation starting in the first month following the asset being put into service (usually the following month from the invoice date). As a result software additions purchased in say November of one year will have 11 months net book value remaining on the books at year end date of December 31.

b) Please see the Table below calculating the 2009 depreciation for software expense:

Depreciation Start Date	2008 Additions	2008 Depreciation	NBV Dec 31 2008	2009 Depreciation		Depreciation Start Date	2009 Additions	2009 Depreciation on 2009 Additions	NBV Dec 31 2009	Total 2009 Depreciation
Jan-08	-		-	-		Jan-09	-	-	-	-
Feb-08	75,947	69,514	6,433	6,433		Feb-09	102,357	93,667	8,690	100,100
Mar-08	46,310	38,720	7,590	7,590		Mar-09	-	-	-	7,590
Apr-08	6,000	4,508	1,492	1,492		Apr-09	69,023	52,002	17,021	53,493
May-08	-	-	-	-		May-09	-	-	-	-
Jun-08	-	-	-	-		Jun-09	3,246	1,903	1,343	1,903
Jul-08	12,540	6,304	6,236	6,236		Jul-09	67,423	35,162	32,261	41,398
Aug-08	-	-	-	-		Aug-09	-	-	-	-
Sep-08	-	-	-	-		Sep-09	-	-	-	-
Oct-08	11,120	2,796	8,325	8,325		Oct-09	-	-	-	8,325
Nov-08	56,579	9,432	47,147	47,147		Nov-09	3,104	519	2,586	47,666
Dec-08			-	-		Dec-09	15,854	1,346	14,508	1,346
						Jan-10	108,207	-	108,207	-
	208,497	131,274	77,223	77,223			369,215	184,599	184,616	261,821
										Sum of Yellows

As a result of monthly depreciation, the total 2009 depreciation of 261,821 is less than the 2009 additions of 369,215.

Interrogatory #8

Ref: Exhibit 2, page 43, Table 2-13

a) **Please explain why the depreciation expense shown for computer software (account 1925) is one-half of the additions for the year in the account. In particular, why is there no additional depreciation expense for the assets that are not fully depreciated at the end of 2010?**

b) **Does NPEI capitalize any depreciation expense, such as the depreciation on transportation equipment? If yes, please show the historical amounts for 2006 through 2010 and the forecasted amount for 2011.**

Response

a) Using the Table below for 2010 Actual, the NBV remaining from 2010 will actually be $224,045 which will be recorded as depreciation in 2011. The actual monthly timing of purchases in 2010 was different than was estimated in the rate application and therefore the depreciation estimated is also different.

							Actual	Actual	Actual	Actual
Depreciation	2009	2009 Depreciation	NBV	Total 2010		Depreciation	2010	2010 Depreciation	NBV	Total 2010
Start Date	Additions	on 2009 Additions	Dec 31 2009	Depreciation		Start Date	Additions	on 2010 Additions	31-Dec-10	Depreciation
Jan-09	-	-	-	-		Jan-10	108,207	108,207	-	108,207
Feb-09	102,357	93,667	8,690	8,690		Feb-10			-	8,690
Mar-09	-	-	-	-		Mar-10	11,621	9,743	1,878	9,743
Apr-09	69,023	52,002	17,021	17,021		Apr-10			-	17,021
May-09	-	-	-	-		May-10			-	-
Jun-09	3,246	1,903	1,343	1,343		Jun-10	4,261	2,498	1,763	3,841
Jul-09	67,423	35,162	32,261	32,261		Jul-10			-	32,261
Aug-09	-	-	-	-		Aug-10	21,400	8,971	12,429	8,971
Sep-09	-	-	-	-		Sep-10			-	-
Oct-09	-	-	-	-		Oct-10			-	-
Nov-09	3,104	519	2,586	2,586		Nov-10	4,985	423	4,562	3,009
Dec-09	15,854	1,346	14,508	14,508		Dec-10	51,142	4,342	46,800	18,850
Jan-10	108,207	-	108,207	-		Jan-11	156,613		156,613	-
	369,215	184,599	184,616	76,409			250,022	134,184	224,045	210,594
								2010 Bridge Year Depreciation		279,283
								Understated		68,689

The rate application depreciation expense for software in 2011 estimated a zero NBV from 2010 and estimated that all of 2011 additions would be made in the first half of the year. Total 2011 software depreciation is 91,435 which will be understated by $224,045. The estimate should be $315,480 based on the actual 2010 timing of additions.

b) NPEI does not capitalize any depreciation expense such as depreciation on transportation equipment.

Interrogatory #9

Ref: Exhibit 2, page 103, Table 2-21

a) **For each bridge year project/line item listed in Table 2-21 please provide the following in a table:**
   i) **the budgeted total cost;**
   ii) **the actual total cost (or the best estimate now available if the final figures are not yet available);**
   iii) **whether or not the project was in service at the end of 2010;**
   iv) **for any projects not completed, please indicate if the project will be in service by the end of 2011.**

b) **Please add any projects completed and placed in service in 2010 that were not included in the budget forecast to the table requested in (a) above at the bottom of the table.**

Response

a) The Table below provides the requested information for each 2010 project/line item. NPEI notes that in Table 2-21 of the application, the total amount of forecast HST ITC savings for 2010 was included as a separate line item. In the table below, the forecast HST savings have been included in each project or line item, to allow for a better comparison to the 2010 actual costs.

Project Number	Project Description	Forecast Total Cost per Table 2-21	2010 Actual Cost	In Service at the end of 2010?	Expected to be in Service by end of 2011?
2010-0001	Robinson St. - Allendale to Fallsview	316,603	304,689	Yes	
2010-0002	High Street Area	225,908	263,441	Yes	
2010-0006	Switchgear Replacement - 4 Units	384,083	470,650	Yes	
2010-0007	Murray St. Area	226,667	208,195	Yes	
2010-0008	Oakwood Drive	194,807	200,502	Yes	
2010-0016	Dorchester NS&T to Morrison	174,917	181,985	Yes	
2010-0017	Campden DS Feeder Egress/Poles	159,501	265,488	Yes	
2010-0020	Kiosk Conversions	496,361	481,606	Yes	
2010-0023	Durham Voltage Conversion	261,315	273,614	Yes	
2010-0024	Cherry Ave.	176,768	181,680	Yes	
2010-0026	South Pelham St. Fonthill	663,166	806,255	Yes	
2010-0033	Fernwood Estates Ph II	197,539	185,784	Yes	
2010-0053	Oakwood Dr at McLeod - Relocate	153,875	158,191	Yes	
2010-1007	Minor Betterments	626,932	656,371	Yes	
2010-1008	Demand Work	265,621	269,926	Yes	
2010-1009	Subdivision & New Lot Connections	499,014	534,966	Yes	
2010-1010	Pole Changes	361,199	466,081	Yes	
2010-2007	Minor Betterments	163,388	350,882	Yes	
2010-2008	Demand Work	130,984	162,579	Yes	
2010-2009	Underground Servicing PW Area	107,381	108,383	Yes	
2010-2010	Pole Changes	295,306	310,440	Yes	
	Meters	194,531	199,654	Yes	
	Mobile Substation	185,185	-	No	Yes
	Contributions and Grants	(1,200,000)	(1,160,428)	Yes	
	Buildings and Fixtures	188,557	67,188	Yes	
	Office Furniture and Equipment	70,564	35,091	Yes	
	Computer Hardware	273,500	257,960	Yes	
	Computer Software	278,954	250,022	Yes	
	Transportation Equipment	824,149	869,037	Yes	
	Tools & Equipment	125,824	141,720	Yes	
	All Projects Under Materiality Threshold	2,632,063	1,451,309	Yes	
2010-0009	Kalar Road Catalina to Beaverdams	148,310	253,934	Yes	
	Total	**9,802,972**	**9,207,196**		
	Add: Smart Meters to Rate Base	4,175,010	4,175,010	Yes	
	Revised Total	**13,977,982**	**13,382,205**		

b) NPEI has identified one 2010 project (Project #2010-0009 Kalar Road Catalina to Beaverdams) with actual total cost above the materiality threshold that was placed in service in 2010, but not included as a separate line item in the original Table 2-21. The 2010 forecast amount for this project was $148,310, which is below NPEI's materiality threshold. Accordingly, the forecast amount was included in the "Projects Under Materiality" line. The actual 2010 cost is $253,934. This project has been added to the bottom of the table above.

Interrogatory #10

Ref: Exhibit 2, page 140

a) **Does NPEI have separate historical information related to capital contributions for the Niagara area and the Peninsula West area? If yes, please provide the total contributions for each for 2006 through 2010, or whatever years are available.**

b) **Please provide a breakdown of the capital contributions forecast for 2011 between the two areas noted above.**

Response

a) Please see the Table below for capital contributions separated by area for the years 2006 to 2010.

IR 10 Capital Contributions By Area

	PenWest Area	Niagara Area	Total
2006	350,450	1,004,008	1,354,458
2007	1,004,002	679,126	1,683,128
2008	543,356	1,169,545	1,712,900
2009	392,325	805,636	1,197,961
2010	676,384	484,044	1,160,428
	2,966,516	4,142,359	7,108,875

b) The capital contributions for 2011 are as follows:

Niagara area	700,000
Peninsula West area	150,000
Total	850,000

Interrogatory #11

Ref: Exhibit 2, pages 151-152, Tables 2-27 & 2-28

a) **Please update the cost of power calculations to reflect the Regulated Price Plan Price Report dated October 18, 2010 and the transmission rates approved by the Board in the EB-2010-0002 proceeding.**

b) **Please replace the cost of power commodity calculations from part (a) above using a Non-RPP Supply Cost of $64.66/MWh and a RPP Supply Cost of $67.36/MWh, as calculated below for Calendar 2011 based on the October 18, 2010 Regulated Price Plan Price Report.**

Ontario Electricity Market Price Forecast

Quarter	Calendar Period	Average	Months in 2011	Weighted Calculation
Q1	Nov 10 - Jan 11	43.59	1	43.59
Q2	Feb 11 - Apr 11	40.59	3	121.77
Q3	May 11 - Jul 11	35.20	3	105.60
Q4	Aug 11 - Oct 11	37.57	3	112.71
Q1	Nov 11 - Jan 12	37.87	2	75.74
	Weighted Average - Calendar 2011			38.28
	Global Adjustment			26.38
	Non-RPP Supply Cost			64.66

Average Supply Cost for RPP Consumers

Load-Weighted Price for RPP Consumers - Nov 10 - Oct 11	42.16
Forecast Wholesale Electricity Price - Nov 10 - Oct 11	39.23
Ratio	1.07468774
Forecast Wholesale Electricity Price - Jan 11 - Dec 11	38.28
Ratio (from above)	1.07468774
Load-Weighted Price for RPP Consumers - Jan 11 - Dec 11	41.14
Global Adjustment	26.38
Adjustment to Address Bias Towards Unfavourable Variance	1.00
Adjustment to Clear Existing Variance	(1.16)
RPP Supply Cost	67.36

Response

a) The table below contains the cost of power calculation, updated to reflect the Regulated Price Plan Report that was issued on October 18, 2010 and the Uniform Transmission Rates ("UTRs") effective January 2011, that were approved in EB-2010-0002 . NPEI notes that the calculation is based on proposed Retail Transmission Service Rates ("RTSRs"), not the UTRs. The RTSRs incorporated in the calculation below were obtained by updating the Board's RTSR Workform to reflect the new UTRs.

Electricity - Commodity	**2011 Forecasted**				
Class per Load Forecast	**Metered kWhs - RPP**	**2011 Loss Factor**		**2011**	
Residential	388,590,040	1.0560	410,347,303	$0.06838	$28,059,549
Street Lighting	6,569,845	1.0560	6,937,692	$0.06838	$474,399
Sentinel Lighting	179,047	1.0560	189,072	$0.06838	$12,929
GS<50kW	101,825,576	1.0560	107,526,818	$0.06838	$7,352,684
GS>50kW	88,078,213	1.0560	93,009,737	$0.06838	$6,360,006
Intermediate		1.0560	0	$0.06838	$0
Unmetered Scattered Load	1,211,706	1.0560	1,279,549	$0.06838	$87,496
TOTAL	**586,454,426**		**619,290,171**		**$42,347,062**

Electricity - Commodity	**2011 Forecasted**				
Class per Load Forecast	**Metered kWhs - Non-RPP**	**2011 Loss Factor**		**2011**	
Residential	70,816,883	1.0560	74,781,940	$0.06561	$4,906,443
Street Lighting	897,746	1.0560	948,011	$0.06561	$62,199
Sentinel Lighting	113,770	1.0560	120,140	$0.06561	$7,882
GS<50kW	19,611,967	1.0560	20,710,046	$0.06561	$1,358,786
GS>50kW	535,728,457	1.0560	565,724,040	$0.06561	$37,117,154
Intermediate		1.0560	0	$0.06561	$0
Unmetered Scattered Load	1,123,722	1.0560	1,186,640	$0.06561	$77,855
TOTAL	**628,292,545**		**663,470,818**		**$43,530,320**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	485,129,243	$0.0061	$2,945,196
Street Lighting		kW	20,107	$1.7148	$34,479
Sentinel Lighting		kW	809	$1.6794	$1,359
GS<50kW		kWh	128,236,864	$0.0055	$705,075
GS>50kW		kW	1,806,009	$2.2682	$4,096,472
Intermediate		kW		$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0055	$13,560
TOTAL					**$7,796,140**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	485,129,243	$0.0046	$2,253,933
Street Lighting		kW	20,107	$1.2375	$24,883
Sentinel Lighting		kW	809	$1.3460	$1,089
GS<50kW		kWh	128,236,864	$0.0041	$521,320
GS>50kW		kW	1,806,009	$1.6108	$2,909,162
Intermediate		kW	0	$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0042	$10,264
TOTAL					**$5,720,652**

Wholesale Market Service					
Class per Load Forecast				**2011**	
Residential		kWh	485,129,243	$0.0052	$2,522,672
Street Lighting		kWh	7,885,703	$0.0052	$41,006
Sentinel Lighting		kWh	309,212	$0.0052	$1,608
GS<50kW		kWh	128,236,864	$0.0052	$666,832
GS>50kW		kWh	658,733,777	$0.0052	$3,425,416
Intermediate		kWh	0	$0.0052	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0052	$12,824
TOTAL					**$6,670,357**

Rural Rate Assistance					
Class per Load Forecast				**2011**	
Residential		kWh	485,129,243	$0.0013	$630,668
Street Lighting		kWh	7,885,703	$0.0013	$10,251
Sentinel Lighting		kWh	309,212	$0.0013	$402
GS<50kW		kWh	128,236,864	$0.0013	$166,708
GS>50kW		kWh	658,733,777	$0.0013	$856,354
Intermediate		kWh	0	$0.0013	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0013	$3,206
TOTAL					**$1,667,589**

	2011
4705-Power Purchased	$85,877,382
4708-Charges-WMS	$6,670,357
4714-Charges-NW	$7,796,140
4716-Charges-CN	$5,720,652
4730-Rural Rate Assistance	$1,667,589
4750-Low Voltage	$360,512
TOTAL	**108,092,632**

The updated cost of power calculation results in a total 2011 forecast cost of power of $108,092,632 versus $99,990,688 as originally filed in the application. This is an increase of $8,101,944, which gives an increase in working capital allowance of $1,215,292 (= $8,101,944 * 15%).

b) The table below contains the cost of power calculation, updated to reflect the requested weighted average 2011 RPP and non-RPP supply costs.

Electricity - Commodity Class per Load Forecast	2011 Forecasted Metered kWhs - RPP	2011 Loss Factor	2011		
Residential	388,590,040	1.0560	410,347,303	$0.06736	$27,640,994
Street Lighting	6,569,845	1.0560	6,937,692	$0.06736	$467,323
Sentinel Lighting	179,047	1.0560	189,072	$0.06736	$12,736
GS<50kW	101,825,576	1.0560	107,526,818	$0.06736	$7,243,006
GS>50kW	88,078,213	1.0560	93,009,737	$0.06736	$6,265,136
Intermediate		1.0560	0	$0.06736	$0
Unmetered Scattered Load	1,211,706	1.0560	1,279,549	$0.06736	$86,190
TOTAL	**586,454,426**		**619,290,171**		**$41,715,386**

Electricity - Commodity Class per Load Forecast	2011 Forecasted Metered kWhs - Non-RPP	2011 Loss Factor	2011		
Residential	70,816,883	1.0560	74,781,940	$0.06466	$4,835,400
Street Lighting	897,746	1.0560	948,011	$0.06466	$61,298
Sentinel Lighting	113,770	1.0560	120,140	$0.06466	$7,768
GS<50kW	19,611,967	1.0560	20,710,046	$0.06466	$1,339,112
GS>50kW	535,728,457	1.0560	565,724,040	$0.06466	$36,579,716
Intermediate		1.0560	0	$0.06466	$0
Unmetered Scattered Load	1,123,722	1.0560	1,186,640	$0.06466	$76,728
TOTAL	**628,292,545**		**663,470,818**		**$42,900,023**

Transmission - Network Class per Load Forecast		Volume Metric	2011		
Residential		kWh	485,129,243	$0.0061	$2,945,196
Street Lighting		kW	20,107	$1.7148	$34,479
Sentinel Lighting		kW	809	$1.6794	$1,359
GS<50kW		kWh	128,236,864	$0.0055	$705,075
GS>50kW		kW	1,806,009	$2.2682	$4,096,472
Intermediate		kW		$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0055	$13,560
TOTAL					**$7,796,140**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**	**2011**		
Residential		kWh	485,129,243	$0.0046	$2,253,933
Street Lighting		kW	20,107	$1.2375	$24,883
Sentinel Lighting		kW	809	$1.3460	$1,089
GS<50kW		kWh	128,236,864	$0.0041	$521,320
GS>50kW		kW	1,806,009	$1.6108	$2,909,162
Intermediate		kW	0	$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0042	$10,264
TOTAL					**$5,720,652**

Wholesale Market Service					
Class per Load Forecast			**2011**		
Residential		kWh	485,129,243	$0.0052	$2,522,672
Street Lighting		kWh	7,885,703	$0.0052	$41,006
Sentinel Lighting		kWh	309,212	$0.0052	$1,608
GS<50kW		kWh	128,236,864	$0.0052	$666,832
GS>50kW		kWh	658,733,777	$0.0052	$3,425,416
Intermediate		kWh	0	$0.0052	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0052	$12,824
TOTAL					**$6,670,357**

Rural Rate Assistance					
Class per Load Forecast			**2011**		
Residential		kWh	485,129,243	$0.0013	$630,668
Street Lighting		kWh	7,885,703	$0.0013	$10,251
Sentinel Lighting		kWh	309,212	$0.0013	$402
GS<50kW		kWh	128,236,864	$0.0013	$166,708
GS>50kW		kWh	658,733,777	$0.0013	$856,354
Intermediate		kWh	0	$0.0013	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0013	$3,206
TOTAL					**$1,667,589**

	2011
4705-Power Purchased	$84,615,409
4708-Charges-WMS	$6,670,357
4714-Charges-NW	$7,796,140
4716-Charges-CN	$5,720,652
4730-Rural Rate Assistance	$1,667,589
4750-Low Voltage	$360,512
TOTAL	**106,830,659**

This updated cost of power calculation results in a total 2011 forecast cost of power of $106,830,659 versus $99,990,688 as originally filed in the application. This is an increase of $6,839,971, which gives an increase in working capital allowance of $1,025,996 (= $6,839,971 * 15%).

Interrogatory #12

Ref: Exhibit 3, page 5

a) **Please explain what is meant on line 8 by "forecasted actual revenue".**

b) **How many months, if any, of actual data, is contained in the 2010 bridge year forecast?**

Response

a) The referenced term “forecasted actual revenue” refers to NPEI’s forecast of what actual 2010 revenues would be, as opposed to a weather normalized forecast.

b) The 2010 Bridge Year forecast contains 7 months of actual revenue, and 5 months of forecasted revenue.

Interrogatory #13

Ref: Exhibit 3, pages 17-19, Tables 3-3, 3-4 & 3-5

a) **Are the customer/connection figures shown in Table 3-3 averages for the year or year-end figures?**

b) **Please update Tables 3-3, 3-4 and 3-5 to reflect actual data for 2010.**

Response

a) The customer/connection figures shown in Table 3-3 are average figures.

b) Please see the updated Tables 3-3, 3-4 and 3-5 to reflect actual data for 2010.

Table 3.3
Summary of Load and Customer/Connection Forecast
Updated

Year	Billed (kWh)	Growth (kWh)	Percentage Change (%)	Customer/ Connection (Count)	Growth (Count)	Percentage Change (%)
2003	1,108,347,420			59,715		
2004	1,135,405,804	27,058,384	2.44%	60,323	608	1.02%
2005	1,208,894,249	73,488,445	6.47%	61,003	680	1.13%
2006	1,184,184,647	-24,709,603	-2.04%	61,856	853	1.40%
2007	1,220,452,820	36,268,173	3.06%	62,459	603	0.97%
2008	1,188,897,732	-31,555,088	-2.59%	63,057	598	0.96%
2009	1,161,778,118	-27,119,614	-2.28%	64,026	968	1.54%
2010	1,170,387,731	8,609,613	0.74%	64,775	749	1.17%
2010 Actual	1,193,712,076	31,933,958	2.73%	64,264	238	0.37%
2011	1,214,746,971	44,359,240	3.79%	65,533	758	1.17%

3.4
Billed Energy and Number of Customers/Connections
By Rate Class
Updated

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Billed Energy (kWh)							
2003	418,838,012	126,366,945	553,710,685	6,713,622	298,685	2,419,471	1,108,347,420
2004	404,285,804	122,937,633	598,431,001	7,027,058	299,222	2,425,087	1,135,405,804
2005	463,562,202	125,194,926	609,950,002	7,458,446	336,743	2,391,930	1,208,894,249
2006	450,017,939	122,020,708	601,216,533	8,236,754	317,191	2,375,520	1,184,184,647
2007	462,721,168	125,994,115	622,092,059	7,023,291	295,243	2,326,944	1,220,452,820
2008	450,470,690	122,663,804	605,669,659	7,504,236	286,832	2,302,512	1,188,897,732
2009	438,952,918	119,930,976	592,972,281	7,271,510	294,273	2,356,161	1,161,778,118
2010	442,125,159	118,817,295	599,437,064	7,368,898	293,544	2,345,772	1,170,387,731
2010 Actual	451,343,387	121,294,614	611,065,862	7,368,898	293,544	2,345,772	1,193,712,076
2011	459,406,923	121,437,543	623,806,670	7,467,591	292,817	2,335,428	1,214,746,971
Number of Customers/Connections							
2003	42,507	3,982	864	11,358	582	422	59,715
2004	42,859	4,033	819	11,588	602	422	60,323
2005	43,068	4,437	802	11,752	522	422	61,003
2006	43,724	4,438	871	11,807	594	422	61,856
2007	44,325	4,339	853	11,933	569	440	62,459
2008	44,955	4,260	847	11,986	564	445	63,057
2009	45,761	4,257	852	12,136	566	454	64,026
2010	46,327	4,304	850	12,271	563	460	64,775
2010 Actual	45,840	4,357	851	12,334	417	465	64,264
2011	46,900	4,352	848	12,408	560	465	65,533

Table 3.5
Annual Usage per Customer/Connection by Rate Class
By Rate Class
Updated

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Energy Usage per Customer/Connection (kWh)						
2003	9,853	31,735	640,869	591	513	5,733
2004	9,433	30,483	730,685	606	497	5,747
2005	10,763	28,216	760,536	635	645	5,668
2006	10,292	27,495	690,260	698	534	5,629
2007	10,439	29,038	729,299	589	519	5,289
2008	10,020	28,794	715,076	626	508	5,175
2009	9,592	28,175	695,793	599	520	5,190
2010	9,550	27,622	705,394	600	522	5,104
2010 Actual	9,846	27,840	718,056	597	704	5,045
2011	9,507	27,080	715,128	602	523	5,020
Annual Growth Rate in Usage per Customer/Connection						
2003						
2004	-4.27%	-3.94%	14.01%	2.59%	-3.15%	0.23%
2005	14.11%	-7.44%	4.09%	4.66%	29.79%	-1.37%
2006	-4.38%	-2.56%	-9.24%	9.92%	-17.22%	-0.69%
2007	1.43%	5.61%	5.66%	-15.63%	-2.83%	-6.05%
2008	-4.01%	-0.84%	-1.95%	6.38%	-2.03%	-2.15%
2009	-4.27%	-2.15%	-2.70%	-4.30%	2.37%	0.29%
2010	-0.45%	-1.96%	1.38%	0.23%	0.23%	-1.65%
2010 Actual	2.65%	-1.19%	3.20%	-0.29%	35.28%	-2.80%
2011	-0.45%	-1.96%	1.38%	0.23%	0.23%	-1.65%

Interrogatory #14

Ref: Exhibit 3, page 25, Table 3-6

Please explain how the 2006 persistence figure for 2011 of 2,653,450 was determined.

Response

The OPA provided NPEI with an Excel spreadsheet containing the results of NPEI's CDM initiatives for 2006 to 2008, including initial year savings and persistence values up to 2011. The 2006 persistence figure for 2011 of 2,653,450 was taken from this spreadsheet. Please see Appendix B, which contains the information that was provided by the OPA.

Interrogatory #15

Ref: Exhibit 3

a) **Please expand Table 3-11 to include historical data for 2002, 2003 and 2004.**

b) **Please update Table 3-11a based on the average loss factor calculated in part (a) above.**

c) **Please update Tables 3-12 and 3-13 to reflect actual 2010 data and the corresponding 2004 through 2010 geometric mean of growth rates.**

d) **Based on the data provided in response to part (c) above, please update Table 3-14 to reflect the level of 2010 actual customers and the 2004 - 2010 geometric means.**

e) **Please update Table 3-16 to reflect 2010 actual data and calculate the geometric mean over the 2003 through 2010 period.**

f) **Please update Table 3-17 to reflect the growth rates determined in part (e) above.**

g) **Based on the results of parts (a) through (f) above, please update Tables 3-18 and 3-20 for the 2011 test year.**

h) **Please update Tables 3-21 and 3-22 to reflect actual 2010 data.**

i) **Please update Table 3-23 to reflect the 2003 - 2010 average ratio from Table 3-22 requested in part (h) above.**

Response

a) Please see below for an updated version of Table 3-11 which includes historical data for 2003 and 2004. NPEI does not have accurate billing data for 2002.

Table 3.11
Historical Distribution Loss Factor
Updated to include 2003 & 2004

Year	Actual Purchases (GWh)	Actual Billed (GWh)	Loss Factor
2003	1,152	1,108	3.94%
2004	1,205	1,135	6.15%
2005	1,272	1,209	5.24%
2006	1,248	1,184	5.39%
2007	1,284	1,220	5.20%
2008	1,248	1,189	5.00%
2009	1,218	1,162	4.80%
		Average	5.10%

b) Please see below for a revised version of Table 3-11a, which has been updated to reflect the average loss factor calculated in a).

Table 3.11a
Weather Normalized Billed Energy
Using 7 Year Average Loss Factor

Year	Predicted Purchases (kWh)	Average Distribution Loss Factor	Weather Normalized Billed Energy (kWh)
	A	B	C = A / B
2010	1,230,381,346	1.0510	1,170,640,367
2011	1,277,014,423	1.0510	1,215,009,182

c) Tables 3-12 and 3-13 below have been updated to reflect actual 2010 data, and the corresponding updated geometric mean of 2004 through 2010.

Table 3.12
Historical Customer/Connection Data
Updated to reflect 2010 Actuals

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2003	42,507	3,982	864	11,358	582	422	59,715
2004	42,859	4,033	819	11,588	602	422	60,323
2005	43,068	4,437	802	11,752	522	422	61,003
2006	43,724	4,438	871	11,807	594	422	61,856
2007	44,325	4,339	853	11,933	569	440	62,459
2008	44,955	4,260	847	11,986	564	445	63,057
2009	45,761	4,257	852	12,136	566	454	64,026
2010 Forecast	46,327	4,304	850	12,271	563	460	64,775
2010 Actual	45,840	4,357	851	12,334	417	465	64,264

Table 3.13
Growth Rate in Customer/Connections
Updated Geometric Mean

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Growth Rate in Customer/Connections						
2003						
2004	0.83%	1.28%	-5.21%	2.03%	3.44%	0.00%
2005	0.49%	10.02%	-2.08%	1.42%	-13.29%	0.00%
2006	1.52%	0.02%	8.60%	0.47%	13.79%	0.00%
2007	1.37%	-2.23%	-2.07%	1.07%	-4.21%	4.27%
2008	1.42%	-1.82%	-0.70%	0.44%	-0.83%	1.13%
2009	1.79%	-0.08%	0.62%	1.26%	0.22%	2.03%
2010	0.17%	2.35%	-0.14%	1.63%	-26.26%	2.42%
Original 2004-2009 Geometric Mean of Growth Rate	1.0124	1.0112	0.9977	1.0111	0.9952	1.0123
2004 - 2010 Geometric Mean of Growth Rate	1.0108	1.0129	0.9978	1.0119	0.9535	1.0140

d) Table 3-14 below has been updated to reflect the actual 2010 data and 2004-2010 geomean as computed in part c).

Table 3.14
Customer/Connection Forecast
Updated to Reflect 2010 Actuals & 2004-2010 Geometric mean

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2010 Forecast	46,327	4,304	850	12,271	563	460	64,775
2011 Forecast (Updated)	46,900	4,352	848	12,408	560	465	65,533
2010 Actual	45,840	4,357	851	12,334	417	465	64,264
2011 Forecast (Updated)	46,337	4,413	849	12,481	398	471	64,949

e) Updated versions of Tables 3-15 and 3-16 are given below, which reflect actual 2010 data and a 2011 forecast based on the updated 2004-2010 geomean.

Table 3.15
Historical Annual Usage per Customer
Updated to reflect 2010 actual usage per customer

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Annual kWh Usage per Customer/Connection						
2003	9,853	31,735	640,869	591	513	5,733
2004	9,433	30,483	730,685	606	497	5,747
2005	10,763	28,216	760,536	635	645	5,668
2006	10,292	27,495	690,260	698	534	5,629
2007	10,439	29,038	729,299	589	519	5,289
2008	10,020	28,794	715,076	626	508	5,175
2009	9,592	28,175	695,793	599	520	5,190
2010 Forecast	9,550	27,622	705,394	600	522	5,104
2010 Actual	9,900	28,000	714,368	600	522	5,104

Table 3.16
Growth Rate in Usage per Customer/Connection
Updated to include 2010 actual

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Annual Growth Rate in Usage per Customer/Connection						
2003						
2004	-4.27%	-3.94%	14.01%	2.59%	-3.15%	0.23%
2005	14.11%	-7.44%	4.09%	4.66%	29.79%	-1.37%
2006	-4.38%	-2.56%	-9.24%	9.92%	-17.22%	-0.69%
2007	1.43%	5.61%	5.66%	-15.63%	-2.83%	-6.05%
2008	-4.01%	-0.84%	-1.95%	6.38%	-2.03%	-2.15%
2009	-4.27%	-2.15%	-2.70%	-4.30%	2.37%	0.29%
2010 Actual	3.20%	-0.62%	2.67%	0.23%	0.23%	-1.65%
Geomean 2004-2010	1.0007	0.9823	1.0156	1.0023	1.0023	0.9835
Original Geomean 2004-2009	0.9955	0.9804	1.0138	1.0023	1.0023	0.9835

f) The version of Table 3-17 below reflects the revised growth rates that were computed in part e)

Table 3.17
Forecast Annual kWh Usage per Customer/Connection
Updated to reflect 2010 actual usage/customer and 2004-2010 geometric mean

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Forecast Annual Usage per Customer/Connection (kWh)						
2010 Forecast	9,550	27,622	705,394	600	522	5,104
2011 Forecast	9,507	27,080	715,128	602	523	5,020
2010 Actual	9,900	28,000	714,368	600	522	5,104
2011 Forecast (Updated)	9,906	27,503	725,534	602	523	5,020

g) Tables 3-18 and 3-20 below have been updated to reflect the results of parts a) to f).

Table 3.18
Non-Normalized Weather Billed Energy Forecast
Updated

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2010 Forecast	442,398,095	118,890,644	599,781,373	7,368,898	293,544	2,345,772	1,171,078,325
2011 Forecast	445,870,313	117,859,337	606,668,653	7,467,591	292,817	2,335,428	1,180,494,138
2010 Actual	451,343,387	121,294,614	611,065,862	7,368,898	293,544	2,345,772	1,193,712,076
2011 Forecast (Updated)	456,877,791	120,377,805	619,655,604	7,462,120	305,633	2,331,508	1,207,010,461

Table 3.20
Alignment of Non-Normal to Weather Normal Forecast
Updated

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2010 Forecast	442,398,095	118,890,644	599,781,373	7,368,898	293,544	2,345,772	1,171,078,325
2011 Forecast	445,870,313	117,859,337	606,668,653	7,467,591	292,817	2,335,428	1,180,494,138
2010 Actual	451,343,387	121,294,614	611,065,862	7,368,898	293,544	2,345,772	1,193,712,076
2011 Forecast (Updated)	456,877,791	120,377,805	619,655,604	7,462,120	305,633	2,331,508	1,207,010,461
Adjustment for Weather (kWh)							
2010 Forecast	-272,936	-73,349	-344,309	0	0	0	-690,594
2011 Forecast	13,536,610	3,578,206	17,138,017	0	0	0	34,252,833
2010 Actual	0	0	0	0	0	0	0
2011 Forecast (Updated)	6,140,162	1,617,805	7,748,860	0	0	0	15,506,828
Weather Normalized Billed Energy Forecast (kWh)							
2010 Forecast	442,125,159	118,817,295	599,437,064	7,368,898	293,544	2,345,772	1,170,387,731
2011 Forecast	459,406,923	121,437,543	623,806,670	7,467,591	292,817	2,335,428	1,214,746,971
2010 Actual	451,343,387	121,294,614	611,065,862	7,368,898	293,544	2,345,772	1,193,712,076
2011 Forecast (Updated)	463,017,953	121,995,611	627,404,464	7,462,120	305,633	2,331,508	1,222,517,289

h) Tables 3-21 and 3-22 below have been updated to reflect actual 2010 data.

Table 3.21
Historical Annual kW per Applicable Rate Class
Updated for 2010 Actuals

Year	General Service > 50 kW	Streetlights	Sentinel Lights
2003	1,573,551	17,588	968
2004	1,673,046	19,480	933
2005	1,719,941	19,789	892
2006	1,777,691	19,932	831
2007	1,884,479	20,188	825
2008	1,735,816	20,371	733
2009	1,753,191	20,319	695
2010 Forecast	1,735,456	19,842	811
2010 Actual	1,769,836	19,656	653

Table 3.22
Historical kW/kWh Ratio per Applicable Rate Class

Year	General Service > 50 kW	Streetlights	Sentinel Lights
2003	0.2842%	0.2620%	0.3241%
2004	0.2796%	0.2772%	0.3118%
2005	0.2820%	0.2653%	0.2649%
2006	0.2957%	0.2420%	0.2620%
2007	0.3029%	0.2874%	0.2794%
2008	0.2866%	0.2715%	0.2556%
2009	0.2957%	0.2794%	0.2362%
2010	0.2896%	0.2667%	0.2225%
Average 2003-2010	0.2895%	0.2689%	0.2696%
Original Average 2003-2009	0.2895%	0.2693%	0.2763%

i) Table 3-23 below has been updated to reflect the average ratio including 2010 data, as calculated in part h).

Table 3.23
kW Forecast by Applicable Rate Class
Updated to Reflect 2010 Actuals

Year	General Service > 50 kW			Streetlights			Sentinel Lights		
	Weather Normalized Billed Forecast (kWh)	Average kW / kWh Ratio	Resulting Forecast kW	Weather Normalized Billed Forecast (kWh)	Average kW / kWh Ratio	Resulting Forecast kW	Weather Normalized Billed Forecast (kWh)	Average kW / kWh Ratio	Resulting Forecast kW
	A	B	C = A*B	D	E	F = D*E	G	H	I = G*H
2010 Forecast	599,437,064	0.2895%	1,735,456	7,368,898	0.2693%	19,842	293,544	0.2763%	811
2011 Forecast	623,806,670	0.2895%	1,806,009	7,467,591	0.2693%	20,107	292,817	0.2763%	809
2010 Actual	611,065,862	0.2896%	1,769,836	7,368,898	0.2667%	19,656	293,544	0.2225%	653
2011 Forecast (Updated)	627,404,464	0.2895%	1,816,517	7,462,120	0.2689%	20,069	305,633	0.2696%	824

Interrogatory #16

Ref: Exhibit 3, page 55, Table 3-30

Please update Table 3-30 to reflect actual 2010 figures.

Response

Please see the updated Table 3-30 Other Operating Revenues

Table 3.30
Other Operating Revenues - Restated for Consistency
Updated for 2010 Actuals

Uniform System of Account #	Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2010 Actual	2011 Test
4080	SSS Administrative Charge	(126,178)	(125,297)	(124,047)	(136,567)	(114,808)	(126,094)	(128,390)	(126,094)
4235	Miscellaneous Service Revenues	(918,570)	(974,099)	(1,028,043)	(912,222)	(951,925)	(884,942)	(853,058)	(956,878)
4225	Late Payment Charges	(432,381)	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(531,694)	(518,557)
4082	RS Rev	(44,777)	(54,443)	(86,142)	(83,876)	(80,996)	(80,748)	(75,303)	(80,748)
4084	Serv Tx Requests	(462)	(4,742)	(5,376)	(2,492)	(1,124)	(2,970)	(3,111)	(2,970)
4090	Electric Services Incidental to Energy Sales	-	-	-	-	-	-	-	-
4205	Interdepartmental Rents	-	-	-	-	-	-	-	-
4210	Rent from Electric Property	(3,894)	-	-	-	-	-	-	-
4215	Other Utility Operating Income	(320,130)	(369,759)	(374,635)	(392,591)	(356,071)	(348,352)	(359,475)	(348,352)
4220	Other Electric Revenues	(33,843)	-	-	-	-	-	-	-
4240	Provision for Rate Refunds	-	-	-	-	-	-	-	-
4245	Government Assistance Directly Credited to Income	-	-	-	-	-	-	-	-
4305	Regulatory Debits	-	-	-	-	-	-	-	-
4310	Regulatory Credits	-	-	-	-	-	-	-	-
4315	Revenues from Electric Plant Leased to Others	-	-	-	-	-	-	-	-
4320	Expenses of Electric Plant Leased to Others	-	-	-	-	-	-	-	-
4325	Revenues from Merchandise, Jobbing, Etc.	(6)	-	-	881	-	-	-	-
4330	Costs and Expenses of Merchandising, Jobbing, Etc	-	-	-	-	-	-	-	-
4335	Profits and Losses from Financial Instrument Hedges	-	-	-	-	-	-	-	-
4340	Profits and Losses from Financial Instrument Investments	-	-	-	-	-	-	-	-
4345	Gains from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-	-
4350	Losses from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-	-
4355	Gain on Disposition of Utility and Other Property	(11,984)	(10)	(186,178)	-	(2,450)	-	(2,850)	-
4360	Loss on Disposition of Utility and Other Property	-	-	-	-	-	-	-	-
4365	Gains from Disposition of Allowances for Emission	-	-	-	-	-	-	-	-
4370	Losses from Disposition of Allowances for Emission	-	-	-	-	-	-	-	-
4375	Revenues from Non-Utility Operations	-	-	-	(50,899)	(182,223)	(116,200)	(110,758)	(65,480)
4380	Expenses of Non-Utility Operations	-	182,603	-	-	-	-	-	-
4385	Expenses of Non-Utility Operations	-	-	-	-	-	-	-	-
4390	Miscellaneous Non-Operating Income	(612,150)	(29,237)	(21,326)	-	(27,284)	(39,937)	(39,937)	(40,000)
4395	Rate-Payer Benefit Including Interest	-	-	-	-	-	-	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	-	-	-	-	-	-	-
4405	Interest and Dividend Income	(475,005)	(455,887)	(769,014)	(461,947)	(81,675)	(46,668)	(74,856)	(46,668)
4415	Equity in Earnings of Subsidiary Companies	-	-	-	-	-	-	-	-
	Total	**(2,979,380)**	**(2,337,359)**	**(3,147,126)**	**(2,389,737)**	**(2,298,920)**	**(2,164,469)**	**(2,179,432)**	**(2,185,747)**
Specific Service Charges		(918,570)	(974,099)	(1,028,043)	(912,222)	(951,925)	(884,942)	(853,058)	(956,878)
Late Payment Charges		(432,381)	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(531,694)	(518,557)
Other Distribution Revenues		(529,284)	(554,241)	(590,199)	(615,526)	(552,999)	(558,164)	(566,280)	(558,164)
Other Income and Expenses		(1,099,145)	(302,531)	(976,518)	(511,965)	(293,632)	(202,805)	(228,401)	(152,148)
Total		**(2,979,380)**	**(2,337,359)**	**(3,147,126)**	**(2,389,737)**	**(2,298,920)**	**(2,164,469)**	**(2,179,432)**	**(2,185,747)**

Interrogatory #17

Ref: Exhibit 3, pages 56 - 57, Table 3-31

a) **Please explain the decrease for 2010 and the increase in 2011 for pole rental revenues shown for account 4235.**

b) **Account 4375 shows OPA incentive revenues of $65,480 for the 2011 test year. Is this the total revenue, or the total revenue less any costs associated with the OPA programs? If the former, please show where the costs associated with the OPA programs is shown.**

c) **Are any vehicles being replaced in 2011? If yes, are these vehicles fully depreciated when they are replaced?**

d) **How are the proceeds from the sale of depreciable property (including vehicles) accounted for? In particular, if any vehicles are being replaced in 2011, why are no proceeds shown in account 4355?**

Response

a) In 2010, NPEI recorded Joint Use payments to Bell in the amount of $33,498 which related to 2009. These payments were missed from being accrued for in 2009. Restated 2009 would be $243,570.

b) Account 4375 includes the total revenue less any costs associated with the OPA programs, 2010 Actual revenues from OPA programs was $60,038. For 2010, NPEI installed Poles for Bell Canada and received $50,720 for this service. This $50,720 is included in account 4375 in 2010. This service is not anticipated to be done in 2011.

c) In 2011, Vehicle #22, a 2000 GMC Safari van for a cost of $22,043 and a Net Book Value of zero will be disposed of. This vehicle is being replaced with a 2011 Cargo Van. If NPEI can obtain a trade-in allowance from this disposal the vehicle being purchased will be recorded at a reduced cost. If NPEI cannot obtain a trade-in allowance NPEI will attempt to sell the vehicle as is and maybe receive $500 to $1,000 in proceeds. Also, PW#14, a 2001 Sterling Bucket truck which is also fully depreciated will be disposed of in the same manner mentioned above.

d) Proceeds from disposal are as follows: a trade-in allowance received reduces the cost of the new vehicle, and any sale proceeds received are recorded on the income statement. No proceeds are recorded in account 4355 for 2011 due to the immateriality and conservative nature of budgeting.

Interrogatory #18

Ref: Exhibit 4, page 5, Table 4-1

a) **Please update Table 4-1 to reflect actual 2010 data. If actual 2010 data is not yet available, please provide a table in the same level of detail as shown in Table 4-1 showing the year-to-date expenditures for 2010 for the most recent period available, along with the corresponding year-to-date figures for 2009.**

b) **How has the inflation rate of 2.0% for 2011 been forecast?**

c) **How has the inflation rate of 1.3% for 2010 been forecast?**

Response

a) Please see the updated Table 4-1 to reflect actual 2010 data as at February 24th 2011.

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year 2010	Variance Bridge 2010 2009 Actuals	Actual 2010	Actual 2010 vs 2009 Actuals	Actual 2010 vs Bridge Year 2010	Test Year 2011	Variance Test 2011 - Bridge 2010	Variance Test 2011 - Actual 2010
Operation	2,811,476	3,603,532	792,055	3,718,160	114,628	3,198,913	(519,247)	3,152,389	(46,524)	3,392,217	239,828	3,305,582	153,193	86,635	3,573,690	181,473	268,108
Maintenance	2,509,155	1,952,232	(556,923)	2,231,951	279,718	2,320,969	89,018	2,390,126	69,157	2,542,929	152,803	2,385,167	(4,959)	157,761	2,568,416	25,488	183,249
Billing and Collecting	2,971,181	3,232,894	261,713	3,371,741	138,847	3,771,715	399,974	3,630,381	(141,334)	3,884,221	253,840	3,999,116	368,735	(114,895)	4,195,729	311,509	196,614
Community Relations	98,291	72,955	(25,336)	83,295	10,340	36,877	(46,418)	64,569	27,692	79,548	14,979	55,391	(9,178)	24,156	81,464	1,916	26,073
Administrative and General	4,138,033	3,691,084	(446,949)	3,816,177	125,093	3,464,139	(352,038)	3,833,199	369,060	3,802,684	(30,516)	3,782,799	(50,401)	19,885	3,876,135	73,452	93,337
Total OM&A Expenses	12,528,137	12,552,697	24,560	13,221,323	668,626	12,792,613	(428,710)	13,070,664	278,051	13,701,598	630,934	13,528,055	457,391	173,543	14,295,435	593,837	767,380
Variance from Previous Year			24,560		668,626		(428,710)		278,051		630,934		457,391	173,543		593,837	767,380
Percent Change (year over year)			0.20%		5.33%		-3.24%		2.17%		4.83%		3.50%	1.27%		4.33%	5.67%
Percent Change (2011 Test vs 2009 actuals)															9.37%		
Percent Change (2011 Test vs 2006 Board Approved)															14.11%		
Average for 2007, 2008, 2009		1.42%															
Compound Annual Growth Rate (for 2007, 2008, 2009)		1.36%															
Inflation Rate		2.1%		1.9%		2.1%		2.3%		1.3%					2.0%		

b) NPEI used an estimate of 2.0% inflation for 2011 which is the same as was used in the Waterloo North Hydro 2011 Cost of Service Rate Application.

c) NPEI used 1.3% inflation for 2010 based on the 2010 IRM rate application where the Price Escalator was 2.3% less 1.0% for productivity factor.

Interrogatory #19

Ref: Exhibit 4, page 14

Please confirm that the Board of Directors costs included in account 5605 are only for the Board of Directors of NPEI and do not include any costs associated with the Board of Directors of any related companies. If this cannot be confirmed, please indicate the amount included in account 5605 in 2011 for the Board of Directors of the related companies.

Response

Account 5605 includes the expenses for the President and only the Board of Directors for NPEI, this account does not include any costs associated with the Board of Directors of any related companies.

Interrogatory #20

Ref: Exhibit 4, page 18, Table 4-3

a) **What is the inflationary payroll increase percentage forecast for 2010 and 2011? If different by group of employees, please provide the percentages for each group of employees (i.e. union, non-union, management).**

b) **What was the actual percentage increase provided in 2010 for each group of employees?**

c) **What is the impact of a 1% reduction in the increase in 2011 for each group of employees on the OM&A costs?**

d) **Were the new positions forecast to be hired in 2010 filled in 2010? If not, please provide details of when these new positions are now forecast to be filled.**

Response

a) The inflationary payroll increase forecasted for 2010 and 2011 were as follows:

Executive and Management received 3% payroll inflationary increase effective January 1st 2010. Two Non-Union employees also received 3% payroll inflationary increases effective January 1, 2010. The Union employees received a 3% payroll inflationary increase effective April 1st 2010, thereby having an annual effective rate of 2.25% for 2010. For 2011 the same forecast was used as an estimate since the collective agreement expires on March 31, 2011.

b)

The actual percentage provided in 2010 for each group was:
Executive and Management received 3% payroll inflationary increase effective January 1st 2010. Two Non-Union employees also received 3% payroll inflationary increases effective January 1, 2010. The Union employees received a 3% payroll inflationary increase effective April 1st

2010, thereby having an annual effective rate of 2.25% for 2010. On November 1st, 2010, the COLA (Cost of Living Adjustment) adjustment of 1% as per the union contract was also adjusted for, for all NPEI employees. This resulted in an effective rate of 3.16667% for executive, management and 5 non-union employees and 2.416667% for union employees for 2010.

c) The impact on OM&A of a 1% reduction in the inflationary payroll increase in 2011 would be as follows calculating a 2% increase for Executive & Management and 5 Non-Union management employees effective January 1 2011 and a 1.5% effective increase for the union and remaining non-union employees (2% increase effective April 1st or 9 months = 1.5%)

	3% or 2.25%	2% or 1.5%	Impact on OM&A
Executive & Management	56,988	37,992	(18,996)
Union	72,009	48,006	(24,003)
NonUnion	6,110	4,074	(2,036)
	135,107	90,072	(45,035)

d) Yes the new positions forecast to be hired in 2010 were filled.

Interrogatory #21

Ref: Exhibit 4, page 54, Table 4-7

Please explain how the costs for services offered to NFHHC, PWP and PWS are accounted for by NPEI. In particular, are the costs shown included in OM&A with a revenue offset in other revenues, or are the cost shown netted out of the OM&A expenses included in the revenue requirement?

Response

The costs shown on Table 4-7 for shared services offered to NFHHC, PWP and PWS are netted out of the OM&A expenses included in the revenue requirement.

Interrogatory #22

**Ref: Exhibit 4, pages 55 - 56, Table 4-8 &
Exhibit 3, page 56 - 57, Table 3-31 &
Exhibit 4, pages 27 - 28, Table 4-5**

a) The evidence related to the charges to affiliates for service provided talks about a profit margin of between 10% and 15%. However, the costs shown in Table 4-8 are equal to the revenues shown (exclude the late payment penalties). Please reconcile.

b) For each of the four cost items shown in Table 4-8, please show where the associated revenues are included in Table 3-31 for the 2011 test year.

c) For each of the four cost items shown in Table 4-8, please show (by account number) where the associated costs are included in Table 4-5 for the 2011 test year.

d) If any of the costs noted above are included in the OM&A costs included in the 2011 revenue requirement, please explain why these amounts are not netted out of the OM&A costs and included in account 4380 in Table 3-31.

Response

a) The total revenue for allocated expenses for 2011 is estimated at $295,000 with actual expenses shown below estimated at $260,000 shown in various different accounts in Table 4-5. Hence the profit margin of 35,000 divided by the total revenue for allocated costs of 295,000 is 11.86%.

b) and c)

Please see the table below detailing the four line items in Table 4-8 outlining how each is recorded.

Cost	2011 Costs	Revenue Account Table 3-31	Expense Account Table 4-5
Labour	435,404	Costs are netted out of the OM&A and not included in the Revenue Requirement, there is no revenue offset. Cost is recorded directly as a receivable from the affiliate	Costs are netted out of the OM&A and not included in the Revenue Requirement, there is no revenue offset. Cost is recorded directly as a receivable from the affiliate
Meter Reading	82,241	Costs are netted out of the OM&A and not included in the Revenue Requirement, there is no revenue offset. Cost is recorded directly as a receivable from the affiliate	Costs are netted out of the OM&A and not included in the Revenue Requirement, there is no revenue offset. Cost is recorded directly as a receivable from the affiliate
Costs directly recorded to affiliate	517,645		

Costs recorded in Revenue and in Expenses

		Revenue Account Table 3-31	Expense Account Table 4-5 Account #	Amount
Depreciation	18,112	Included in Miscellaneous line in Account 4235 last line in Table 3-31 on page 56 see Table from Board IR 9b)	In Depreciation expense account # 5705 which is not included in Table 4-5	18,112
Allocated Expenses	295,000	Account 4215 in Table 3-31	5315	192,313
		Water Billing Admin Charge	5610	42,191
		2011 amount = (295,169)	5615	14,264
			5620	11,232
				260,000
	313,112			278,112

d) NPEI has recorded the revenues and expenses for these affiliate services in account 4215, 4235 and all of the expense accounts noted above consistently since 2002 on the RRR filings. NPEI will consider changing the recording of these affiliate services revenues and expenses to account 4380 on the 2010 RRR filing.

Interrogatory #23

Ref: Exhibit 4, page 57

a) Please provide the actual cost associated with the Asset Management Plan prepared by Kinetrics when the report is completed.

b) What is the total amount invoiced to date or to be invoiced for legal fees associated with the 2011 rate application?

Response

a) The total cost is $75,000 for the Kinetrics Asset Condition Assessment and Asset Management Plan. In account 1190 Prepaid Regulatory as at December 31, 2010, there was $55,000 of this $75,000 incurred. The balance of $20,000 will be paid and recorded in 2011.

b) The total of account 1190 Prepaid Regulatory as at December 31, 2010 is as follows:

Account 1190-Prepaid Regulatory
2011 Rate Application
Expenses incurred up to December 31,2010

Legal fees	$11,442.42
Audit Smart Meters	$4,650.00
Notice in Paper	$2,747.72
	$18,840.14
Kinetrics-Asset condition	$55,000.00
	$73,840.14

Note the balance of Kinetrics to be recorded and paid in 2011

Interrogatory #24

Ref: Exhibit 4, page 60, Table 4-12

a) **Are the figures shown in Table 4-12 an average for the year, or the year-end number of employees?**

b) **Please update Table 4-12 to reflect actual figures for 2010.**

Response

a) The figures shown in Table 4-12 employees by department are the year end number of employees as at December 31, 2010.

b) Please see below an updated Table 4-12 that reflects actual figures for 2010.

Table 4-12 Updated
2010 Number of Employees by Department

	Original	Original	Original	Updated at Dec 31 2010
	2010	2004		2010
Department	**Number**	**Number**	Change	**Number**
Executive	5	7	-2	5
Finance(General Admin, Accounting & Regulatory)	10	6	4	10
Customer Service (Customer Service & Billing & Collection)	36	32	4	38
Engineering	18	13	5	18
Operations & Maintenance	55	44	11	52
Purchasing/Stores	3	4	-1	3
Health Safety and HR	3	1	2	3
Information Technology	3	1	2	3
Total Employees by Major Department	**133**	**108**	25	132

Interrogatory #25

Ref: Exhibit 4, pages 87 - 88, Tables 4-25 & 4-26

a) **Please provide a revised Table 4-25 for the 2010 bridge year assuming that a full year of depreciation was taken on the capital additions in the same manner as they were in 2009 and prior years.**

b) **Please provide a revised Table 4-26 for the 2011 test year (based on the half year rule as used) if there is any impact from the changes requested in part (a) above (for example, an increase in the fully depreciated amount for 2011 that may result from the higher depreciation expense in 2010).**

Response

a) The Table below is a revised version of Table 4-25, reflecting a full year of depreciation taken on additions.

Account	Description	Openning Balance	Less Fully Depreciated	Net for Depreciation	Disposal	Additions	Closing Balance 2006	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Adjustments	Total Depreciation
		(a)	(b)	© =(a) - (b)	(c1)	(d)		(e)= (©-c1)+1.0x(d)	(f)	(g)=1/(f)	(h)=(e)/(f)	(i)	(j)=(h)+(i)
1805	Land	507,274	0	507,274		0	507,274	507,274			0	0	0
1806	Land Rights	1,598,170	0	1,598,170		0	1,598,170	1,598,170	25	0.04	63,927	(7,077)	56,850
1808	Buildings and Fixtures	111,638	0	111,638		0	111,638	111,638	25	0.04	4,466	5,196	9,661
1810	Leasehold Improvements	0	0	0		0	0	0			0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,558,514	0	6,558,514		0	6,558,514	6,558,514	40	0.03	163,963	(18,985)	144,978
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,507,465	924,634	3,582,831		185,185	4,692,651	3,768,017	25	0.04	150,721	(17,443)	133,277
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	28,665,012	8,329,566	20,335,446		2,860,613	31,525,625	23,196,059	25	0.04	927,842	(38,060)	889,782
1835	Overhead Conductors and Devices	31,395,023	2,048,498	29,346,525		1,231,327	32,626,350	30,577,852	25	0.04	1,223,114	(30,602)	1,192,512
1840	Underground Conduit	10,367,640	0	10,367,640		1,175,040	11,542,680	11,542,680	25	0.04	461,707	(265,743)	195,965
1845	Underground Conductors and Devices	54,396,854	321,277	54,075,577		1,723,794	56,120,648	55,799,371	25	0.04	2,231,975	110,123	2,342,098
1850	Line Transformers	31,103,686	3,366,951	27,736,735		1,384,010	32,487,696	29,120,745	25	0.04	1,164,830	(13,656)	1,151,174
1855	Services	3,459,629	0	3,459,629		486,923	3,946,552	3,946,552	25	0.04	157,862	(2)	157,860
1860	Meters	6,677,338	1,340,931	5,336,407	958,531	4,369,541	10,088,349	8,747,418	25	0.04	349,897	(30,643)	319,254
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	508,970	0	508,970		0	508,970	508,970			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	12,391,184	1,817,234	10,573,950		188,557	12,579,740	10,762,506	60	0.02	179,375	32,829	212,204
1910	Leasehold Improvements	120,252	120,252	(0)		0	120,252	(0)	3	0.33	(0)	0	0
1915	Office Furniture and Equipment	1,107,299	628,664	478,635		70,564	1,177,863	549,199	10	0.10	54,920	23,133	78,052
1920	Computer Equipment - Hardware	2,624,840	1,953,498	671,341		273,500	2,898,340	944,841	5	0.20	188,968	85,739	274,708
1925	Computer Software	1,920,006	1,735,390	184,616		278,954	2,198,960	463,570	1	1.00	463,570	(44,810)	418,760
1930	Transportation Equipment	5,484,897	3,706,634	1,778,263		824,149	6,309,047	2,602,413	8	0.13	325,302	124,602	449,904
1935	Stores Equipment	200,261	182,660	17,601		18,900	219,161	36,501	10	0.10	3,650	804	4,454
1940	Tools, Shop and Garage Equipment	1,566,110	1,257,226	308,884		94,342	1,660,452	403,226	10	0.10	40,323	26,969	67,291
1945	Measurement and Testing Equipment	183,146	133,421	49,725		4,690	187,835	54,415	5	0.20	10,883	17,601	28,484
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	158,934	92,379	66,555		2,843	161,777	69,398	4	0.25	17,350	1,872	19,222
1960	Miscellaneous Equipment	67,903	46,643	21,260		5,049	72,952	26,309	5	0.20	5,262	1,691	6,952
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	128,961	0		0	128,961	0	15	0.07	0	0	0
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(16,320,649)	0	(16,320,649)		(1,200,000)	(17,520,649)	(17,520,649)	25	0.04	(700,826)	23,080	(677,746)
2005	Property under Capital Lease	143,036	143,036	0		0	143,036	0	25	0.04	0	0	0
	Total before Work in Process	**189,633,833**	**28,277,856**	**161,355,977**	**958,531**	**13,977,982**	**202,653,283**	**174,375,428**			**7,489,096**	**(13,400)**	**7,475,697**
	Work in Process												
	Total after Work in Process	**189,633,833**	**28,277,856**	**161,355,977**	**958,531**	**13,977,982**	**202,653,283**	**174,375,428**			**7,489,096**	**(13,400)**	**7,475,697**

The following table indicates the effect of using a full year of depreciation in 2010:

2011 Test Year	Per Application (Half Year Rule applied in 2010)	Per EP IR 25 (Full Year of Depreciation taken in 2010)	Difference
2010 Depreciation Expense	7,000,940	7,475,696	474,756
2011 Opening Net Book Value	100,989,102	100,514,346	(474,756)
2011 Depreciation Expense	7,143,688	7,143,688	-
2011 Closing Net Book Value	102,948,206	102,473,450	(474,756)
2011 Rate Base	119,144,943	118,670,187	(474,756)
2011 Deemed Interest Expense	4,340,146	4,322,851	(17,294)
2011 Deemed Return on Equity	4,694,311	4,675,605	(18,705)
2011 Revenue Deficiency (before tax)	2,451,313	2,419,960	(31,353)
2011 Revenue Deficiency (grossed up)	3,378,275	3,334,910	(43,364)
2011 Service Revenue Requirement	32,421,330	32,377,965	(43,364)

b) There is no impact on the 2011 depreciation expense.

Interrogatory #26

**Ref: Exhibit 4, pages 94 - 96 &
Exhibit 4, page 71, Table 4-13**

a) **Please confirm that the Ontario surtax claw-back on the first $500,000 of taxable income was eliminated effective July 1, 2010 and that the provincial income tax rate on the first $500,000 of taxable income was reduced to 4.50%.**

b) **Has NPEI included a tax reduction of $36,250 related to the Ontario small business tax rate on the first $500,000 in taxable income (calculated as $500,000 times the difference between 11.75% and 4.50%)? If not, why not?**

c) **Please explain how the $40,000 in other additions (apprenticeship tax credits) shown in Table 4-31 was derived.**

d) **Please provide a calculation of the Ontario apprenticeship training tax credit, showing the number of eligible positions and the amount that can be claimed for each position for the 2011 test year.**

e) **Please provide a calculation of the Federal Apprenticeship Job Creation Tax Credit, showing the number of eligible positions and the amount that can be claimed for each position for the 2011 test year.**

f) **Please reconcile the number of positions used in the responses for parts (d) and (e) with the number of apprentices hired in 2008 through 2011 as shown in Table 4-13.**

g) **Has NPEI included any tax credits related to the cooperative education tax credit? If not, why not? Please show the number of positions that qualify for the credit and the average amount of the credit, along with the total credit that could be claimed in 2011, if applicable.**

Response

a) NPEI confirms that the Ontario surtax claw-back on the first $500,000 of taxable income was eliminated effective July 1, 2010 and that the provincial income tax rate on the first $500,000 of taxable income was reduced to 4.50%.

b) NPEI did not include a tax reduction of $36,250 related to the Ontario small business tax rate on the first $500,000 in taxable income because NPEI was unaware that cell E20 on Tab Q. PILs, Tax Provision of the CoS Tax Model needed to be an input cell. NPEI was not aware of this change at the time it submitted its rate application. Please see a revised Tab Q with the reduction below

PILS OR INCOME TAXES WORK FORM

Name of LDC: Niagara Peninsula Energy Inc.

File Number: EB-2010-0138

Rate Year: 2011

PILs,Tax Provision

						Wires Only	
Regulatory Taxable Income						$ 6,287,703	A
Ontario Income Taxes							
Income tax payable	**Ontario income tax**	11.75%	B	$ 738,805	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D				
	Rate reduction	-7.25%	E	-$ 36,250	F = D * E		
Ontario Income tax						$ 702,555	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.17%	K = J / A		
	Federal tax rate			16.50%	L		
	Combined tax rate					27.67%	M = L + L
Total Income Taxes						$ 1,740,026	N = A * M
Investment Tax Credits						$ 11,000	O
Miscellaneous Tax Credits						$ 40,000	P
Total Tax Credits						$ 51,000	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						$ 1,689,026	R = N - Q
Corporate PILs/Income Tax Provision Gross Up				72.33%	S = 1 - M	$ 646,253	T = R / S - N
Income Tax (grossed-up)						$ 2,335,279	U = R + T
Ontario Capital Tax (not grossed-up)						$ -	V
Tax Provision for Test Year Rate Recovery						$ 2,335,279	W = U + V

c) The $40,000 in other additions (apprenticeship tax credits) shown in Table 4-31 was estimated based on 2009's actual ATC of $39,937.

d) The following table calculates the 2011 Ontario Apprenticeship Job Creation Tax Credit

Provincial

Hired by NPEI per Table 4-13	Registration Date	36th month end date	48th month end date hired after 26-Mar-09	NPEI Start date	2011 Employ Eligible wages	Claim amount 2011 T4	APPC = Lessor of 35% or 10,000 2011	2011APPC
2008 Apprentice	7-Feb-08	6-Feb-11		2-Sep-08	Not returning in 2011	-	-	-
2008 Apprentice	7-Feb-08	6-Feb-11		2-Sep-08	Jan to Feb 5th 2011	4,492	1,572	1,572
2009 Apprentice	4-Nov-08	4-Nov-11		19-May-09	Jan to Nov 4th 2011	27,509	9,628	9,628
2009 Apprentice	4-Nov-08	4-Nov-11		19-May-09	Jan to Nov 4th 2011	25,899	9,065	9,065
2010 Apprentice	6-Jan-10		5-Jan-14	30-Aug-10	Sept - December 2011	13,441	4,704	4,704
2010 Apprentice	6-Jan-10		5-Jan-14	30-Aug-10	Sept - December 2011	13,413	4,695	4,695
						84,755	29,664	29,664

e) The following table calculates the 2011 Federal Apprenticeship Job Creation Tax Credit for 2011:

Federal

Hired by NPEI per Table 4-13	Registration Date	24th month end date	NPEI Start date	2011 Employ Eligible wages	Claim amount 2011 T4	ITC = Lessor of 10% or 2,000 2011	Federal 2011 ITC
2010 Apprentice	6-Jan-10	6-Jan-12	30-Aug-10	Sept - December	13,441	1,344	1,344
2010 Apprentice	6-Jan-10	6-Jan-12	30-Aug-10	Sept - December	13,413	1,341	1,341
					26,855	2,685	2,685

f) Please see the following summary and reconciliation of the number of positions used above reconciled to Table 4-13 for the apprentices hired from 2008 to 2011:

Summary

	2010 Actual	2011 Estimate	2011 Test Year Per Rate Application
Federal Apprenticeship	7,411	2,685	11,000
Provincial Apprenticeship	68,443	29,664	40,000
	75,854	32,350	51,000

Federal

Hired by NPEI per Table 4-13	Registration Date	24th month end date	NPEI Start date	2011 Employ Eligible wages	Claim amount 2011 T4	ITC = Lessor of 10% or 2,000 2011	Federal 2011 ITC
2008 Apprentice	7-Feb-08	6-Feb-10	2-Sep-08	None	-	-	0
2008 Apprentice	7-Feb-08	6-Feb-10	2-Sep-08	None	-	-	-
2009 Apprentice hired FT	11-Apr-07	10-Apr-09	21-Dec-09	None	-	-	0
2009 Apprentice hired FT	5-Sep-07	4-Sep-09	23-Nov-09	None	-	-	0
2009 Apprentice	4-Nov-08	4-Nov-10	19-May-09	None	-	-	0
2009 Apprentice	4-Nov-08	4-Nov-10	19-May-09	None	-	-	0
2009 Apprentice	1-Jun-05	1-Jun-07	27-Apr-09	None	-	-	0
2010 Apprentice	6-Jan-10	6-Jan-12	30-Aug-10	Sept - December	13,441	1,344	1,344
2010 Apprentice	6-Jan-10	6-Jan-12	30-Aug-10	Sept - December	13,413	1,341	1,341
					26,855	2,685	2,685

Provincial

Hired by NPEI per Table 4-13	Registration Date	36th month end date	48th month end date hired after 26-Mar-09	NPEI Start date	2011 Employ Eligible wages	Claim amount 2011 T4	APPC = Lessor of 35% or 10,000 2011	2011APPC
2008 Apprentice	7-Feb-08	6-Feb-11		2-Sep-08	Not returning in 2011	-	-	-
2008 Apprentice	7-Feb-08	6-Feb-11		2-Sep-08	Jan to Feb 5th 2011	4,492	1,572	1,572
2009 Apprentice hired FT	11-Apr-07	10-Apr-10		21-Dec-09	None	-	-	-
2009 Apprentice hired FT	5-Sep-07	4-Sep-10		23-Nov-09	None	-	-	-
2009 Apprentice	4-Nov-08	4-Nov-11		19-May-09	Jan to Nov 4th 2011	27,509	9,628	9,628
2009 Apprentice	4-Nov-08	4-Nov-11		19-May-09	Jan to Nov 4th 2011	25,899	9,065	9,065
2009 Apprentice	1-Jun-05	31-May-08		27-Apr-09	None	-	-	-
2010 Apprentice	6-Jan-10		5-Jan-14	30-Aug-10	Sept - December 2011	13,441	4,704	4,704
2010 Apprentice	6-Jan-10		5-Jan-14	30-Aug-10	Sept - December 2011	13,413	4,695	4,695
						84,755	29,664	29,664

g) NPEI has not included a cooperative education tax credit for the 2011 test year because it does not plan to hire a cooperative position in 2011.

Interrogatory #27

Ref: Exhibit 4, page 96, Table 4-31

Are there any regulatory assets included in the reserves added or deducted in the adjustments to accounting income? If yes, please separate out the amounts associated with regulatory assets from the remainder of the reserves forecast for additions and deductions from the accounting income.

Response

Yes the reserves added and deducted include regulatory assets. Please see a revised Table 4-30 Adjustments to Accounting Income for 2010 and a revised Table 4-31 Adjustments to Accounting Income for 2011 separating out the amounts associated with regulatory assets.

Revised Table 4-30
Adjustments to Accounting Income 2010
Separate out Regulatory asset/liability Reserve changes

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Interest and penalties on taxes	103	1,039	0	1,039
Amortization of tangible assets	104	7,000,940	0	7,000,940
Reserves from financial statements- balance at end of year **non reg asset/liability**	126	3,654,594	0	3,654,594
Reserves from financial statements- balance at end of year		8,059,280		
Other Additions (Apprenticeship Tax Credits)	295	39,937	0	39,937
Total Additions		**18,755,790**	**0**	**10,696,510**
Deductions:				
Capital cost allowance from Schedule 8	403	7,329,316	0	7,329,316
Cumulative eligible capital deduction from Schedule 10	405	91,378	0	91,378
Reserves from financial statements - balance at beginning of year **non reg asset**	414	3,612,877	0	3,612,877
Reserves from financial statements - balance at beginning of year		7,629,013		
Total Deductions		**18,662,584**	**0**	**11,033,571**
Tax Adjustments to Accounting Income		**93,207**	**0**	**(337,060)**

Change in Reserves non- regulatory asset/liab revised	41,717
Change in Reserves regulatory asset/liability	430,267
	471,984

Revised Table 4-31
Separate out Regulatory asset/liability Reserve changes
Adjustments to Accounting Income 2011

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Amortization of tangible assets	104	7,143,688	0	7,143,688
Reserves from financial statements- balance at end of year **non reg asset/liability**	126	3,696,311	0	3,696,311
Reserves from financial statements- balance at end of year		8,250,360		
Other Additions (Apprenticeship Tax Credits)	295	40,000	0	40,000
Total Additions		**19,130,359**	**0**	**10,879,999**
Deductions:				
Capital cost allowance from Schedule 8	403	7,463,388	0	7,463,388
Cumulative eligible capital deduction from Schedule 10	405	84,982	0	84,982
Reserves from financial statements - balance at beginning of year **non reg asset**	414	3,654,594	0	3,654,594
Reserves from financial statements - balance at beginning of year		8,059,280		
Total Deductions		**19,262,243**	**0**	**11,202,963**
Tax Adjustments to Accounting Income		**(131,884)**	**0**	**(322,964)**

Change in Reserves revised	41,717
Change in Reserves regulatory asset/liability	191,080
	232,797

Interrogatory #28

Ref: Exhibit 4, page 107

a) **What is the amount of LEAP that will be included in the revenue requirement?**

b) **Has NPEI included any other assistance in the 2011 revenue requirement? If yes, please quantify the amount included.**

Response

a) The LEAP amount would be 0.12% times $32,421,330 = $38,906.

b) NPEI has not included any other assistance in the 2011 revenue requirement.

Interrogatory #29

Ref: Exhibit 5, page 3, Table 5-1, Appendix A

a) **Please explain the Date of Issuance of September 30, 2015 for the term loan for smart meters.**

b) **Please explain the sentence at lines 13 through 15 on page 3. In particular, please clarify the phrase "either upon demand by the City of Niagara Falls ($22,000,000) or Niagara Falls Hydro Holding Corporation ($3,605,090) respectively".**

c) **Please show the specific wording in the promissory notes shown in Appendix A that indicates that these notes are callable with one year's notice.**

Response

a) The actual Date of Issuance for the term loan for smart meters is September 30, 2010 with a term September 30, 2015. This was a typing mistake. Please see a revised Table 5-1 which was also submitted to the Board Staff question number 15c).

Table 5-1: 2011 Weighted Average Cost of Capital							
Description	Debt Holder	Affiliated with LDC?	Date of Issuance	Principal Balance at December 31, 2011	Term (Years)	Rate%	Interest Cost Per Amortization Schedule
Long term note payable	City of Niagara Falls	Y	April 1, 2000	$22,000,000	20	7.25%	$1,595,000
Long term note payable	Niagara Falls Hydro Holding Corporation	Y	April 1, 2000	$3,605,090	20	7.25%	$261,369
Long term bank loan	Scotiabank	N	June 1, 2004	$3,398,502	10	6.44%	$192,771
Term loan	TD	N	July 19, 2009	$7,965,243	10	4.58%	$348,793
Term loan smart meters	Scotiabank	N	September 30, 2010	$4,143,643	10	4.97%	$215,605
Total				$41,112,478			$2,613,538
Weighted Average Cost of Long Term Debt						6.36%	

b) The phrase should read “either upon demand by the City or on April 1, 2020 (the Maturity Date)” and the phrase “either upon demand by HoldCo or on April 1, 2020 (the Maturity Date)” which come directly from the promissory notes in the last sentence of the first paragraph.

c) The phrase “either upon demand by the City or on April 1, 2020 (the Maturity Date)” which is the last sentence of the first paragraph combined with paragraph four “At the option of the City, on one year’s prior written notice to WiresCo, the Maturity Date and any of the terms of the Promissory Note may be revised, changed or restated by the City in consultation with WiresCo. The same wording is in the HoldCo Promissory note.

Interrogatory #30

Ref: Exhibit 8, page 26, Table 8-22

a) **The loss factors shown in Table 8-22 illustrate a continuing decline from 2006 through 2009. To what does NPEI attribute this trend?**

b) **Please update Table 8-22 to add actual data for 2010.**

Response

a) As indicated in Exhibit 8 of the application, NPEI has several initiatives in place which have and will continue to reduce distribution losses including:

- Distribution transformers that are purchased for use on Niagara Peninsula Energy's system are assessed to ensure that no load and full load losses are minimized.

- Distribution transformers are sized with consideration given to minimizing losses for new or replacement installations.

- Line losses are considered by the Engineering Department when selecting a particular primary or secondary conductor size for use on Niagara Peninsula Energy's system.

- Feeders are monitored regularly and re-configured as necessary to ensure that load is evenly distributed across station transformers and feeders.

NPEI has also completed several voltage conversion projects, which are described in Exhibit 2, that have contributed to an improved loss factor.

b) Table 8-22 below has been updated to reflect actual 2010 data.

	Table 8-22 Loss Factor Calculations Updated to Include 2010							
		2005	2006	2007	2008	2009	2010 Actual	6 Year Average
	Losses in Distributor's System							
A_1	"Wholesale" kWh delivered to distributor (higher value)	1,277,916,200	1,253,674,100	1,289,693,990	1,253,960,160	1,223,022,413	1,265,254,731	7,563,521,594
A_2	"Wholesale" kWh delivered to distributor (lower value)	1,272,191,339	1,248,057,840	1,283,916,366	1,248,342,618	1,217,543,467	1,259,586,591	7,529,638,222
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)							
C	Net "Wholesale" kWh delivered by distributor **(A_2)-(B)**	1,272,191,339	1,248,057,840	1,283,916,366	1,248,342,618	1,217,543,467	1,259,586,591	7,529,638,222
D	"Retail" kWh delivered by distributor	1,208,894,249	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	1,193,712,076	7,157,919,642
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)							
F	Net "Retail" kWh delivered by distributor **(D)-(E)**	1,208,894,249	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	1,193,712,076	7,157,919,642
G	Loss Factor in distributor's system **[(C)/(F)]**	1.0524	1.0539	1.0520	1.0500	1.0480	1.0552	1.0519
	Losses Upstream of Distributor's System							
H	Supply Facility Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses							
I	Total Loss Factor **[(G)x(H)]**	1.0571	1.0587	1.0567	1.0547	1.0527	1.0599	1.0567

Interrogatory #31

Ref: Exhibit 8, page 38

There are significant increases in the monthly fixed charge for a number of classes in the proposed rates as compared to those currently in place for the Peninsula West customers. These increases will have a significant impact on low volume customers in each rate class. Did NPEI consider phasing in the increase in the fixed charges to help mitigate the impact on low volume customers? If not, why not?

Response

NPEI did consider phasing in the harmonization of the Residential rates in order to mitigate the greater than 10% total bill impacts for all of NPEI's customers. NPEI has operated as a merged company since January 1, 2008. For three years the former Peninsula West Utilities residential urban and suburban customers have had lower rates than the residential customers from the former Niagara Falls Hydro. In 2010 the delivery portion of a monthly hydro bill for a Niagara Falls residential customer using 800 kWh per month is $26.84, a Peninsula West urban residential customer using the same 800 kWh per month is $24.44 and a Peninsula West suburban customer is $21.37. One purpose of harmonization is to ensure there is no cross subsidization within a rate class for customers who receive the same service. In this rate application NPEI harmonized all residential customers into one class. There are, low volume customers in both the Niagara Falls area and the Peninsula West area however there is no low volume rate class and hence no rate mitigation is being proposed for any residential customers whether they are low volume or not. Treating low volume Peninsula West residential customers differently than low volume Niagara Falls residential customers is not prudent or fair.

The government has initiated programs such as LEAP to assist low income customers and NPEI will participate in these programs.

We continue to work with all of NPEI's customers on conservation education to decrease usage and payment arrangements due to the impact of any bill.

Appendix A
Asset Management Plan

Niagara Peninsula Energy Incorporated

Asset Management Plan
2011 – 2015

TABLE OF CONTENTS

1 Executive Summary

1.1 Objective of AMP

Niagara Peninsula Energy Inc.'s (NPEI) Asset Management Plan provides a high level overview of the corporation as well as a summary of the corporate objectives, strategies, and practices that go into developing a business plan.

The resultant business plan is summarized in this document for the period 2011-2015 with more details, such as major projects and programs, included for 2011, by dividing expenditures in the major investment buckets under capital, O&M, Billing and Collecting and General and Administrative categories.

The Asset Management Plan could and should be used as a means of sharing information about NPEI and the rational for investments it makes with customers, shareholders, regulators and the general public.

1.2 AMP Components

The Asset Management Plan includes a number of sections. The following is a brief description of the contents for each section:

<u>About NPEI – Section 2</u>

This section provides a description of NPEI's company's overview, geographic location and demand and energy consumption (both historical and forecasted).

<u>Corporate Information – Section 3</u>

This section provides high level corporate information that governs decision making processes and includes vision, mission statement, and corporate values.

<u>System Description and Reliability Performance – Section 4</u>

This section gives a description of the NPEI's distribution system and provides information on all supply points, SCADA, major asset categories and reliability performance, including historical values for SAIFI, SAIDI and CAIDI.

<u>Major External Challenges – Section 5</u>

This section lists external challenges that, in order to be addressed properly, require NPEI to make significant investments, mostly capital in nature. These external challenges include Smart Grid development, DG connections, new loads, both residential and commercial, and municipal infrastructure improvement projects, such as a road widening.

Internal Initiatives – Section 6

This section describes major internal initiatives aimed at improving the performance of NPEI's distribution system. These initiatives include a number of programs, such as replacement of high voltage switching kiosks and submersible transformers, inspection and replacement of poles and pad mounted equipment, and vegetation management.

Business Practices –Section 7

This section describes NPEI's business practices and approach specifically regarding replacement and maintenance of existing distribution assets.

Asset Condition Assessment – Section 8

This section presents results and recommendations from the Asset Condition Assessment study for the distribution assets performed by an external consultant (Kinectrics Inc).

2011 Business Plan – Section 9

This section presents 2011 Business Plan divided into 6 major buckets: Sustainment Capital, Development Capital, Other Capital, Operations & Maintenance, Billing and Collecting and General and Administration. Major programs and projects are also identified within each investment bucket.

2012-2015 Business Plan – Section 10

This section presents the 2012-2015 Business Plans for each of the years in the range using the same buckets as for 2011 Business Plan but without identifying major projects and programs.

2 About NPEI

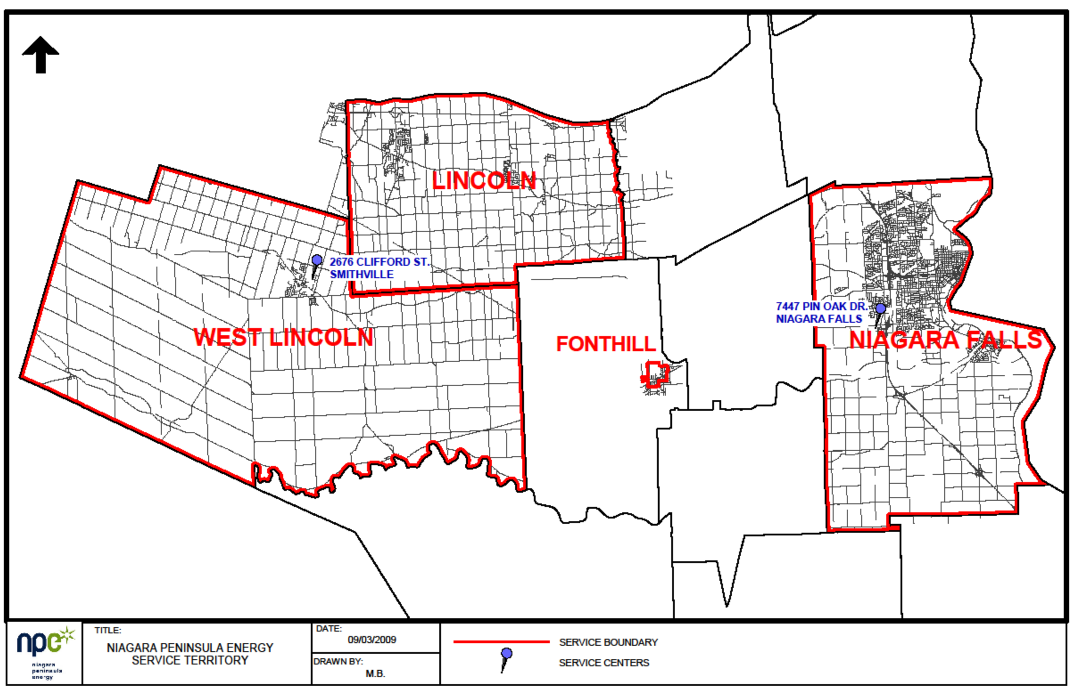
2.1 Company Overview

Niagara Peninsula Energy Inc. (NPEI) was established in 2008 as a result of the amalgamation of Niagara Falls Hydro Incorporated and Peninsula West Utilities Limited. NPEI is a medium sized utility in the Province of Ontario and is responsible for providing all regulated electricity distribution services to over 50,000 residential and business customers in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. Niagara Peninsula Energy has a service area of 827 sq. km.

The table below shows NPEI's Provincial ranking in 3 major categories: number of customers, Net Book Value of Assets and geographic territory.

	Area (sq. km.)	Number of Customers	NBV ($M)
NPEI	827	> 50,000	101
Ontario Rank	6	14	9

2.2 Geographic Map



NPEI's neighboring utilities are Fortis, Welland Hydro, Niagara-on-the Lake Hydro, Hydro One, Horizon Utilities, Haldimand County Hydro and Grimsby Power.

2.3 Customer Base

Niagara Peninsula Energy Inc. (NPEI) services approximately 45,616 residential and 5,311 commercial customers. Customers in urban portions of the service territory are as follows:

Area	Size	Customers
Niagara Falls Urban	60.8 sq. km.	31,850
Beamsville	10.3 sq. km.	4,153
Vineland	5.9 sq. km.	1,714
Fonthill	1.8 sq. km.	1,161

The majority of NPEI's service territory is rural. NPEI has 748.2 sq. km. of rural territory servicing approximately 12,049 customers.

2.4 Demand and Energy

2.4.1 Energy Usage

The following table summarizes NPEI's energy usage in 2009 and 2010 to present. The remaining columns for 2012 to 2015 are the projected demand forecast for NPEI:

	Energy (gWh)						
Month	2009	2010	2011	2012	2013	2014	2015
January	118	112	117	117	117	118	118
February	98	99	103	103	103	103	104
March	102	100	103	104	104	104	105
April	92	89	92	93	92	93	93
May	91	98	101	102	102	102	103
June	98	107	111	111	111	111	112
July	106	130	135	135	135	136	136
August	118	125	130	130	130	131	131
September	97	98	102	102	102	102	103
October	94	95	99	99	99	99	100
November	94	95	98	99	99	99	100
December	110	111	115	116	116	116	117

Legend:

	Actual Usage Data
	Forecasted Using the Weather Normalization Model
	Forecasted Based on Assumptions

Energy Usage Forecast Assumptions:

In the years 2012 through 2015, a moderate energy growth of 0.5% is expected year to year. In 2013, NPEI anticipates that energy usage will drop by 0.25% based on the expected completion of the Ontario Power Generation tunnel project in Niagara Falls.

2.4.2 Demand

The following table summarizes NPEI's demand between 2009 and 2015. From 2009 to August 2010, the demand values were obtained from metered data. The remainder of the table contains the projected demand values based on the assumptions stated below:

	Demand (MW)						
Month	2009	2010	2011	2012	2013	2014	2015
January	180	190	187	188	185	186	187
February	183	181	190	191	187	188	189
March	187	167	181	182	178	179	180
April	150	156	156	157	153	154	155
May	157	220	198	199	196	197	198
June	223	223	241	242	239	240	241
July	205	261	265	266	262	264	265
August	255	253	271	272	268	270	271
September	187	188	196	197	193	194	195
October	161	163	169	170	166	167	168
November	177	179	186	187	184	184	185
December	194	196	202	204	201	202	203

Legend:

	Actual Demand Data
	Forecasted Based on Assumptions

Demand Forecast Assumptions:

In the years 2011 through 2015, the forecasted demand is based on the energy usage forecast and average load factor per month from 2009 and 2010. In 2013, NPEI anticipates that demand will drop by 3 MW based on the expected completion of the Ontario Power Generation tunnel project in Niagara Falls. The tunnel project's demand on NPEI's system averages 3 MW per month.

2.4.3 Load Factor

The following table summarizes NPEI's calculated load factor between 2009 and 2015:

	Demand (MW)						
Month	2009	2010	2011	2012	2013	2014	2015
January	89.6%	80.9%	85.3%	85.3%	86.7%	86.7%	86.7%
February	73.2%	74.7%	74.0%	74.0%	75.1%	75.1%	75.1%
March	74.6%	81.9%	78.3%	78.3%	79.6%	79.6%	79.6%
April	84.0%	78.1%	81.0%	81.0%	82.6%	82.6%	82.6%
May	79.2%	60.9%	70.0%	70.0%	71.1%	71.1%	71.1%
June	60.2%	65.5%	62.8%	62.8%	63.6%	63.6%	63.6%
July	71.3%	68.1%	69.7%	69.7%	70.5%	70.5%	70.5%
August	63.7%	67.7%	65.7%	65.7%	66.4%	66.4%	66.4%
September	71.1%	71.1%	71.1%	71.1%	72.2%	72.2%	72.2%
October	79.9%	79.9%	79.9%	79.9%	81.3%	81.3%	81.3%
November	72.4%	72.4%	72.4%	72.4%	73.6%	73.6%	73.6%
December	77.8%	77.8%	77.8%	77.8%	79.0%	79.0%	79.0%

Legend:

	Calculated Load Factor

3 Corporate Information

3.1 Vision Statement

Niagara Peninsula Energy is committed to delivering environmentally responsible and sustainable energy for the future of our communities.

3.2 Mission Statement

Niagara Peninsula Energy delivers safe, efficient and reliable electricity through dedicated employees in an environmentally sustainable and technologically focused manner. We provide excellence in customer service and respond to the needs of our communities.

3.3 Corporate Values

Niagara Peninsula Energy and its staff will maintain conduct with commitment to the values of:

- Integrity- we are ethical and our actions are truthful and trustworthy
- Fairness- we treat everyone equally and free of bias
- Responsibility- we provide services with safety first for our customers and employees
- Respect- we listen to each other and see value that each member of the team brings and respect the needs of our stakeholders
- Transparency- we are open and accountable for our actions and decisions

4 System Description and Reliability Performance

4.1 System Description

NPEI's distribution system consists of 1059 km of overhead primary feeders and 482 km of underground primary cable. The distribution system operates at one of the following four primary voltages:

- 27.6kV
- 13.8kV
- 8.32kV
- 4.16kV

NPEI's distribution system receives power from the Hydro One operated transmission system through one of the following supply points:

Substation Name	Primary Voltage	Secondary Voltage	# of Transformers	Station Owner	City/Town
Pelham DS	27.6 kV	4.16 kV	1	NPEI	Fonthill
Station DS	27.6 kV	4.16 kV	1	NPEI	Fonthill
Beamsville TS	115 kV	27.6 kV	2	Hydro One	Lincoln
Campden DS	27.6 kV	8.32 kV	1	NPEI	Lincoln
Greenlane DS	27.6 kV	8.32 kV	2	NPEI	Lincoln
Jordan DS	27.6 kV	8.32 kV	1	NPEI	Lincoln
Vineland DS	115 kV	27.6 kV	2	Hydro One	Lincoln
Kalar TS	115 kV	13.8 kV	2	NPEI	Niagara Falls
Murray TS	115 kV	13.8 kV	4	Hydro One	Niagara Falls
NF Station 3	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 6	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 7	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 8	13.8 kV	4.16 kV	2	NPEI	Niagara Falls
NF Station 10	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 14	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 17	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 18	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 22	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
NF Station 23	13.8 kV	4.16 kV	1	NPEI	Niagara Falls
Stanley TS	13.8 kV	4.16 kV	2	Hydro One	Niagara Falls
Bismark DS	27.6 kV	8.32 kV	1	Hydro One	West Lincoln
Niagara West TS	230 kV	27.6 kV	2	NWTC	West Lincoln
Smithville DS	27.6 kV	8.32 kV	1	NPEI	West Lincoln

NPEI monitors its distribution system through a supervisory control system at its main office located in Niagara Falls. The system is used to monitor and control all TS supply breakers feeding NPEI's distribution system. The Supervisory Control and Data Acquisition System ("SCADA") is monitored twenty-four hours a day, seven days a week.

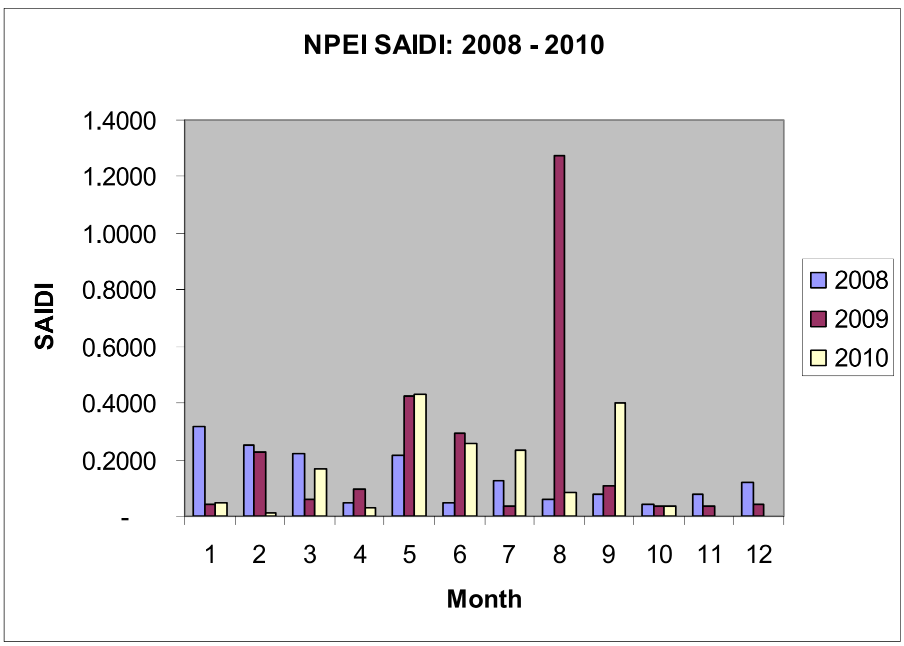
4.2 Main Asset Categories

The table below shows the number of assets in each of NPEI's major asset categories:

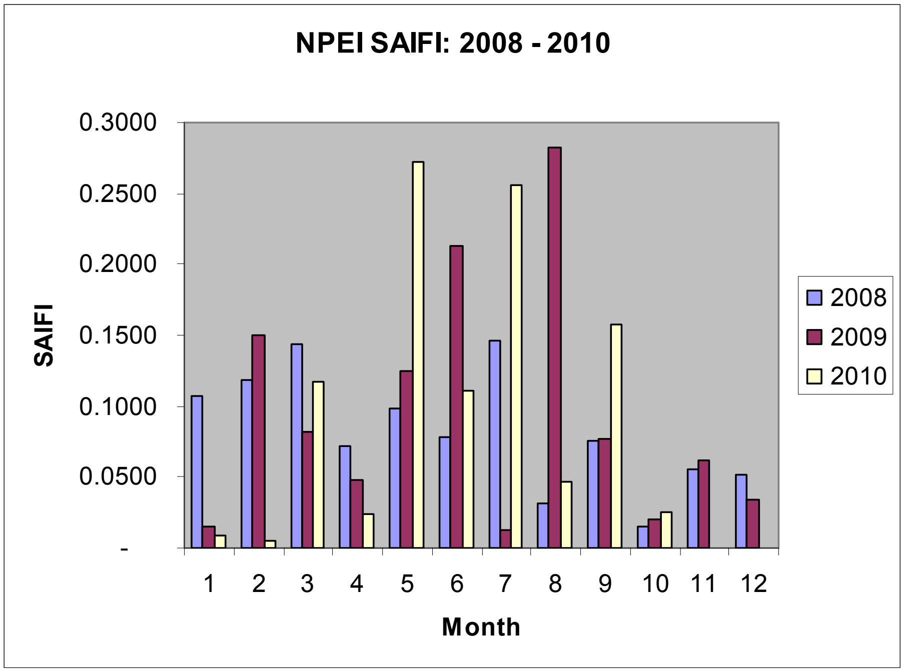
Asset Description	Population
Station Power Transformers	21
Large Pad Mounted Transformers (> 750 kVA)	56
Standard Pad Mounted Transformers (< 750 kVA)	2408
Pole Top Transformers	6835
Poles	22247
Pad Mounted Switchgear	89

4.3 System Performance

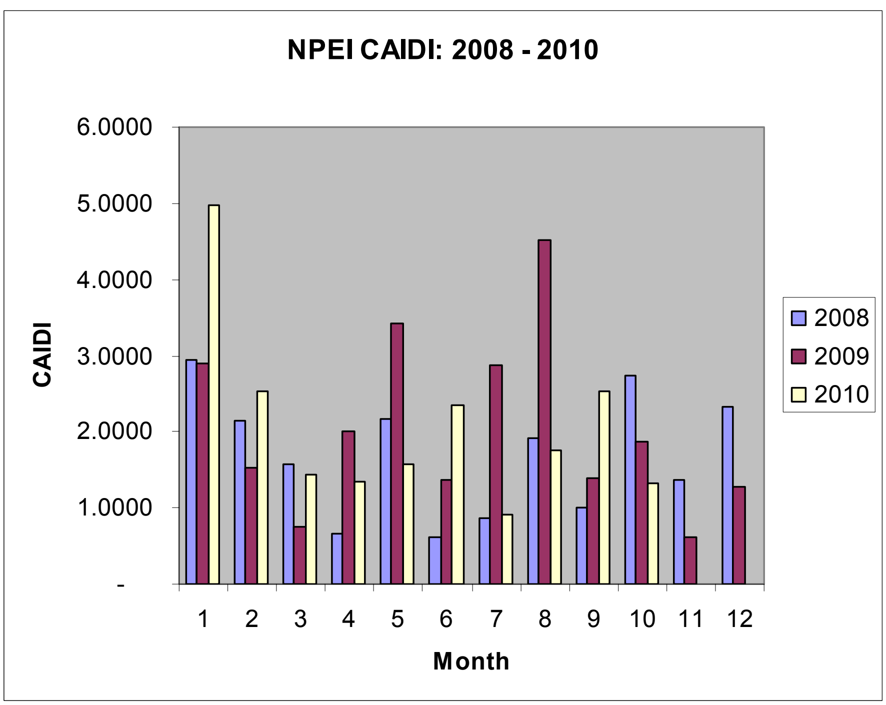
The following chart summarizes NPEI's System Average Interruption Duration Index (SAIDI) by month for 2008 through 2010:



The following chart summarizes NPEI's System Average Interruption Frequency Index (SAIFI) by month for 2008 through 2010:



The following chart summarizes NPEI's Customer Average Interruption Duration Index (CAIDI) by month for 2008 through 2010:



NPEI has compiled outage data used to derive SAIDI, SAIFI, and CAIDI since the merger. This data as well as historical values from the former two utilities indicate higher than desired values for SAIDI, specifically in the western portion of NPEI's service territory. Following the merger, NPEI has implemented initiatives that specifically target improving this index such as the installation of feeder sectionalizing and advanced reclosing devices. In 2010 NPEI's distribution system performed with an improved SAIDI compared to previous years.

5 Major External Challenges

5.1 Smart Grid

NPEI is in the early stages of developing a formal smart grid strategy. NPEI leverages a mature geographic information system (GIS) to manage asset data. NPEI'S high level strategy is to build on the current GIS functionality in support of smart grid operations.

NPEI is currently implementing a work force management / outage management (WFMS/OMS) system that leverages GIS data. This system is used to manage the distribution of work to NPEI crews as well as to manage the distribution system operationally. NPEI has a long term strategy to integrate smart meters and smart devices with the OMS as the foundation of its smart grid.

Smart Grid technologies are factored into new equipment purchases where feasible from a technical and cost perspective.

5.2 DG Connections

NPEI currently has 30 microFIT connections on its system and is averaging 5 new connections per month as of December 2010. NPEI also has 1.25MW of generation connected under the FIT program as well as applications for an additional 10MW.

5.3 Municipal Commitments – Load Growth

NPEI has experienced a moderate and consistent level of load growth in the residential customer class. Approximately 500 new residential customer connections have been performed per year since the incorporation of NPEI.

Commercial development in NPEI's service area has been consistent since incorporation. Approximately 1.5 MVA of new commercial load has been connected to NPEI's system per year.

Currently, NPEI does not supply any significant industrial sector load.

NPEI anticipates that the level of growth in both the residential and commercial customer classes will remain consistent in the coming years. A capital expenditure allowance has been established to permit the connection of new customer loads based upon historical levels.

5.4 Municipal Commitments – Infrastructure

NPEI's capital expenditures have been influenced significantly by external factors in recent years. Federal and provincial stimulus funding for infrastructure improvements has resulted in a substantial increase in municipally driven construction activities. Due to obligations under the Municipal Act to accommodate road reconstruction projects, NPEI has substantially increased capital expenditures related to these activities.

We anticipate that a return to pre-stimulus infrastructure spending levels will reduce the capital requirement for these types of projects. Going forward, NPEI has allocated capital funding for such projects based on pre-stimulus historical requirements. As such projects are externally driven; NPEI may experience elevated levels of investments in this area.

6 Major Internal Initiatives

6.1 Information Technology Initiatives

NPEI manages data related to its assets in a corporate geographic information system (GIS). The GIS is Intergraph's G/Technology system designed and customized for electric utilities based in Ontario. All of the distribution assets that are managed by NPEI are modeled within the GIS. NPEI has invested heavily in GIS data as it provides a foundation for managing the lifecycle of assets. NPEI has integrated the GIS to its corporate customer information system (CIS), financial systems, analysis software, and its outage management system.

Inspection data collected by NPEI is linked to specific asset features within GIS. The GIS is used to analyze inspection results and prioritize the required corrective maintenance or replacement activities. Any maintenance activity and associated data is also tracked in the GIS.

NPEI routinely uses Distribution Engineering Simulation Software (DESS) to analyze the distribution system. NPEI has integrated DESS with the GIS to ensure that the model used for engineering analysis is kept current with minimal effort. DESS supports decisions made by NPEI's engineering and operations staff related to the design and operation of the distribution system.

NPEI is currently implementing an outage management system (OMS). The GIS provides the data utilized by the OMS and as such, the two systems have been integrated. The OMS automates several stages of outage management for operations staff at the utility. The system tracks and manages calls, predicts probable points of failure, and provides a mechanism to dispatch outage related work orders to field crews electronically. Beyond outage type work flows, the system also provides work force management capability. The system is utilized to mange work assignment to operations field staff electronically.

6.2 Kiosk/Submersible Replacement Program

NPEI's distribution system contains approximately 200 legacy switching cubicle installations referred to as kiosks. A kiosk is a masonry structure with a metal or concrete lid that contains primary voltage switching apparatus. These installations do not conform to current distribution standards and are at end of life. The installations are inspected on a 5 year cycle to confirm condition. The inspection results are assessed annually to prioritize units that require replacement with new equipment. In a typical year, NPEI replaces 15 to 20 kiosks.

NPEI also has submersible distribution transformer installations on its system which are at end of life. These installations do not meet current standards and are subject to premature failure. A program is in place to replace these installations with pad mounted transformation. At the end of 2010, NPEI had 18 submersible installations remaining on its distribution system. NPEI typically replaces approximately 20 of these installations a year which will lead to the elimination of submersible transformers from the system by the end of 2011.

6.3 Pole Replacement Program

NPEI has been inspecting and testing poles on its distribution system since 2004. Approximately 5000 poles are tested per year. Wood poles are tested using a sound and bore method. Steel and concrete poles are visually inspected. All overhead distribution apparatus installed on poles are visually inspected at the time of the pole test.

The resulting data from the annual pole testing program is analyzed in order to prioritize the required pole replacements. NPEI replaces between 150 and 250 poles annually under the pole replacement program.

6.4 Switchgear Replacement Program

NPEI has 89 primary voltage switchgear installations on its distribution system. Approximately 20 units are inspected annually. The inspection consists of a visual condition assessment, infrared scan, and ultrasonic scan.

The resulting data from the annual switchgear inspection program is analyzed in order to prioritize the required switchgear replacements. NPEI replaces approximately 4 units per year under the switchgear replacement program.

6.5 Vegetation Management

Following the merger in 2008, NPEI adjusted its tree trimming program for the overall service area. The western portion of the service area (Lincoln, West Lincoln and Fonthill) is split into 4 trimming areas (1 per year) based on experience in growth rate. The eastern portion of the service area (Niagara Falls) is split into 5 trimming areas (1 per year).

6.6 Other Reliability Initiatives

NPEI strives to improve reliability on its distribution system through the design and incorporation of features such as:

- Wildlife Bushing Guards
- Insulated Drop Leads
- Insulated Switch Brackets/Bases
- Over Insulated Components
- Increased Designed Clearances
- Encapsulated Switching and Terminal Components
- Covered Line Wire
- Advanced Reclosers and Controls

The application of these components minimizes the occurrence of foreign interference with the distribution system that negatively impacts the reliability of service to our customers.

7 Business Practices

7.1 *Proactive vs. Reactive Replacements*

Based on replacement practices, assets can be divided into 2 distinct categories: assets that are replaced "reactively" only when they fail, and assets that are replaced "pro-actively" based on their condition before they fail.

Failure of assets that are replaced "proactively" usually does not result in significant cost and/or risk to corporate objectives and values. Conversely, failure of assets that are replaced "reactively" usually results in significant incremental cost over and above planned replacement cost and, furthermore, poses high risk to objectives and values.

NPEI "proactively" replaces distribution facilities as part of the Internal Initiatives described in the Section 6.

7.2 *Maintenance Practices*

NPEI follows the requirements outlined in the distribution system code. The following table summarizes maintenance practices on major equipment within NPEI's asset base:

Equipment	Cycle	What is Done
TS/DS Inspection	Monthly	Visual Inspection
Station Transformers	Annually	Oil Analysis, Dissolved Gas Analysis, Visual Inspection
Large Padmounted Transformers	Annually	Oil Analysis, Dissolved Gas Analysis, Visual Inspection
Small Padmounted Transformers	5 Year Cycle	Infrared Scan, Ultrasonic Scan, Visual Inspection
Poles	5 Year Cycle	Sound and Bore (Structural Integrity Assessment), Treatment Application, Component Inspection
Switchgear	5 Year Cycle	Infrared Scan, Ultrasonic Scan, Visual Inspection
Manholes/Civil Structures	5 Year Cycle	Visual Inspection, Cleaning
Switching Kiosks	5 Year Cycle	Condition Review, Prioritized Elimination of Legacy Equipment
Vegetation Management	5 Year Cycle	5 Year Cutback

7.3 Work Integration

NPEI adjusts its maintenance practices and sustainment capital programs due to their inherent interdependencies and to account for internal initiatives. An adjustment is made in situations where commercial and operational benefits can be achieved. Examples of this include:

- Reducing capital replacement cost projections to account for distribution plant that will be replaced as a part of an externally driven project, such as a municipal road widening
- Initiation of a rebuild project rather than per pole replacement approach due to the quantity of identified deficiencies in a test area
- Extension in maintenance activities to provide increased life expectancy in distribution assets where a known end of service date exists

8 Asset Condition Assessment

NPEI retained the services of Kinectrics Inc. to carry out an Asset Condition Assessment of NPEI's key distribution assets. The resulting Distrubtion Asset Condition Assessment report is included in Appendix A of this document.

9 2011 Business Plan

9.1 Sustaining Capital with Major Project Types

Item	Project Type	Sustainment Capital
1	Replacement of distribution facilities due to deteriorated condition	$2,005,619
2	Line extensions/relocations due to municipal road work requirements	$388,370
3	Replacement of poles identified with limited structural integrity	$1,226,524
4	Required overhead line rebuild of deteriorated facilities identified in the pole condition survey	$776,740
5	Replacement of kiosks and submersible transformers	$480,835
6	Minor Betterments	$488,926
		$5,367,014
	Less Capital Contributions	$-100,000
	Total	**$5,267,014**

9.2 Development Capital with Major Project Types

Item	Project Type	Development Capital
1	Expansion of the primary distribution system to accommodate load growth and reliability requirements	$1,295,495
2	Subdivisions and new residential services	$631,059
3	Demand based system requirements for new commercial service connections and expansions	$1,156,938
	Projects under materiality	$194,185
		$3,227,677
	Less Capital Contributions	$-750,000
	Total	**$2,527,677**

9.3 Other Capital

Item	Type	Other Capital
1	Metering	$185,185
2	Vehicles	$462,963
3	Other Capital	$659,954
	Total	**$1,308,102**

9.4 O&M with Major Categories

Item	Type	Other Capital
1	Stations	$190,778
2	Overhead Lines	$1,921,782
3	Underground	$651,140
4	Other	$3,378,406
	Total	**$6,142,106**

9.5 Billing and Collecting with Major Categories

Item	Type	Other Capital
1	Billing	$3,302,566
2	Collecting	$893,163
3	Community Relations	$81,464
	Total	**$4,277,193**

9.6 General and Administration

Item	Type	Other Capital
1	G & A	$3,876,136

10 2012-2015 Business Plan

10.1 Sustaining Capital

Year	Amount
2012	$5,223,331
2013	$5,320,205
2014	$5,368,186
2015	$5,464,149

10.2 Development Capital

Year	Amount
2012	$2,766,249
2013	$2,908,623
2014	$2,981,100
2015	$3,101,559

10.3 Other Capital

Year	Amount
2012	$1,324,074
2013	$1,273,148
2014	$1,273,148
2015	$1,273,148

10.4 O&M

Year	Amount
2012	$6,278,477
2013	$6,418,728
2014	$6,562,315
2015	$6,709,323

10.5 Billing and Collecting

Year	Amount
2012	$4,365,422
2013	$4,463,294
2014	$4,563,847
2015	$4,667,161

10.6 General and Administration

Year	Amount
2012	$3,963,342
2013	$4,052,768
2014	$4,144,473
2015	$4,238,521

Appendix A – NPEI Distribution Asset Condition Assessment Report

The remaining pages of this document contain the Distribution Asset Condition Assessment Report produced by Kinectrics Incorporated.

Niagara Peninsula Energy Inc

Distribution Asset Condition Assessment

Kinectrics Report: K-418046-RC-001-R3

February 10, 2011

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue, Unit 2, Toronto, Ontario, Canada M8Z 6C4

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Niagara Peninsula Energy Inc.

@Kinectrics Inc., 2011.

DISTRIBUTION ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418046-RC-001-R3

February 10, 2011

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Dated: Feb 9, 2011

Revision History

Revision Number	Date	Comments	Approved
R0	December 20, 2010	Initial Draft	N/A
R1	January 28, 2011	Final Draft	N/A
R2	February 9, 2011	Final Report	SC
R3	February 10, 2011	Final Report (re-formatted)	

EXECUTIVE SUMMARY

Niagara Peninsula Energy Inc (NPEI) retained Kinectrics Inc. (Kinectrics) to carry out an Asset Condition Assessment (ACA) of NPEI's key distribution assets. The assets were divided into several Asset Groups. For each of these Asset Groups, the ACA included the following tasks:

- Derive Health Indexes
- Conduct Field Surveys
- Provide Capital Replacement Plan
- Recommend condition data gap closure strategy

This report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

Information Availability and Health Index Methodology

The general methodology for Asset Condition Assessment is described, while each Asset Group is presented in detail in its own section. Where appropriate, the formulations were modified based on the expert opinion of NPEI staff, for example air-insulated pad mounted switchgear located near major roads were automatically assigned poor condition and, thus, flagged for replacement. Field observations generally supported the Health Index distribution derived using Kinectrics' methodology. Some differences could be attributed to the fact that the field survey observations weigh all the condition parameters equally while the Health Index formulation used a weighted sum of condition parameters scores.

Health Index Results Summary

For six of the seven Asset Groups there was sufficient asset information to calculate Health Indexes. Table ES - 1 shows, for each of the seven Asset Group, the total number of assets, sample size, and Health Index distribution. Detailed results for each Asset Group are shown in Section C RESULTS AND FINDINGS.

Table ES - 1 Health Index Results Summary

ASSET			SAMPLE SIZE		HEALTH INDEX DISTRIBUTION				
No	Description	Population	Units	%	Very Poor	Poor	Fair	Good	Very Good
1	Power Transformers	21	*21*	*100%*	0%	17%	26%	22%	35%
2	Large Pad Mounted Transformers	56	*51*	*91%*	0%	2%	6%	27%	65%
3	Standard Pad Mounted Transformers	2,408	*716*	*30%*	5%	1%	1%	4%	89%
4	Pole Top Transformers	6,835	*6,711*	*98%*	1%	4%	11%	17%	67%
5	Poles	22,247	*5,985*	*27%*	0%	5%	6%	28%	61%
6	Pad Mounted Switchgear	89	*38*	*43%*	8%	34%	3%	18%	37%

Capital Replacement Plan

The Capital Replacement Plan (CRP) includes two aspects: the number of units that are planned to be replaced and the corresponding replacement cost. For asset categories 2 through 6 capital requirements for the whole population were extrapolated from the sample and the comments regarding appropriateness of such an assumption were included in Section C for each of these asset categories.

The number of units to be replaced was estimated based on asset condition and the corresponding probability of failure. Table ES - 2 summarizes the assumed replacement cost, replacement plan approach, and resultant capital replacement plan in the first year as well as the capital replacement plan approach. Assets which are 'run to failure' are replaced reactively, compared to those assets which are replaced proactively.

Table ES - 2 Capital Replacement Plan Summary

Asset	Assumed Replacement Cost	Units to Replace in First Year	Planned Capital Replacement Cost in First Year	CRP Approach
Power Transformers	$300,000	1	$300,000	Proactive
Large Pad Mounted Transformers	$45,000	0	$0	Proactive
Standard Pad Mounted Transformers	$15,000	31	$465,000	Proactive
Pole Top Transformers	$5,000	38	$190,000	Reactive
Poles	$5,000	160	$800,000	Reactive
Pad Mounted Switchgear	$75,000	5	$375,000	Proactive

The scheduling of capital expenditure for assets which are replaced **proactively** has been levelized so replacement is done over a period of time after the optimal replacement year. Those assets which are replaced **reactively** also have a levelized schedule so replacement is done over a period of time before the optimal replacement year. This methodology is to ensure that run to failure assets are replaced before they fail.

Figure ES – 1 presents the Overall Levelized Capital Replacement Plan. This is the total replacement projections for all the assets over the next five (5) years in 2011 dollars (cost does not take inflation rates into account).

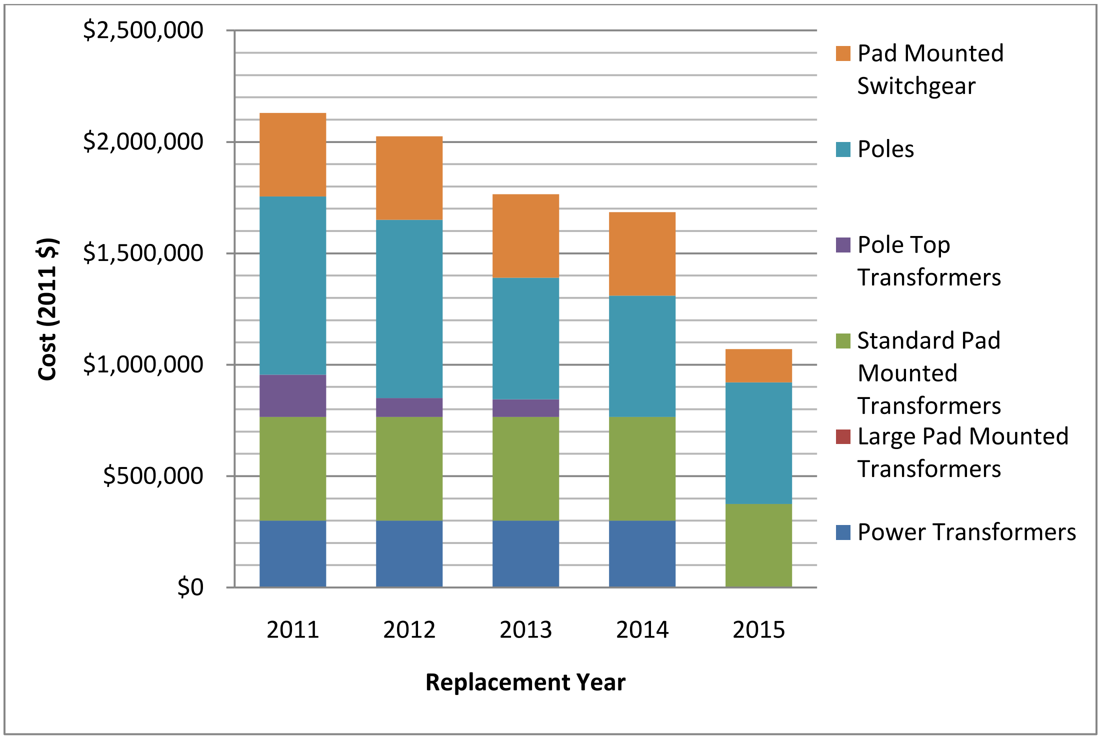

Figure ES - 1 Five Year Capital Replacement Plan

Conclusions and Recommendations

1. There was generally sufficient condition data available for Power Transformers, Large Pad-mounted Transformers, Poles (inspected after 2008) and Switchgear.

2. For Pole-mounted transformers, only age and operating practices were available (i.e., number of customers serviced by each transformer). Gathering and recording detailed inspection data should be considered.

3. For Standard Pad Mounted Switchgear, age was provided for 87% of the population however sufficient data was provided for only 28% of the population. It is recommended that NPEI collect data for a greater population of Pad Mounted Switchgear.

4. For Poles that have not been inspected, age is only available for half of the population. Sufficient age and inspection data should be collected for the rest of the population.

5. Sufficient data was not available for Underground Cables. It is recommended that inspection and maintenance information be collected for these assets to enable future asset condition assessment.

6. Comparison of poles with adequate condition data vs poles with only age known shows that the former have a better overall condition than the latter. This is due to the fact that over the last several years substantial capital investments were made to achieve that. It is therefore recommended that capital investments be made to bring be made to bring the rest of the pole population to the same Health Index distribution as the subset with adequate condition data.

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A INTRODUCTION

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To: Niagara Peninsula Energy
7447 Pin Oak Drive
Niagara Falls, ON L2E 6S5

INTRODUCTION

Niagara Peninsula Energy Inc (NPEI) supplies electricity to homes and businesses and is regulated by the Ontario Energy Board.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and components and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

NPEI retained the services of Kinectrics to carry out condition assessment of its electrical distribution system assets.

A considerable portion of this work was devoted to the development of Health Indices based on the information provided by NPEI, a brief visual field survey conducted by Kinectrics and the expert opinion of NPEI staff.

This report presents the findings of the NPEI's distribution assets condition assessment and includes the development of Health Indices for the specified Asset Groups.

Objective

Kinectrics performed an Asset Condition Assessment of NPEI's electrical distribution system. The following distribution system assets, referred to as Asset Groups throughout this report, were covered under the scope of work for this project:

1 Power Transformers
2 Large Pad-Mounted Transformers
3 Standard Pad-Mounted Transformers
4 Pole-Top Transformers
5 Poles
6 Pad Mounted Switchgear

As part of the asset condition assessment, a visual inspection of the power system physical assets was conducted by Kinectrics. The objective of the inspections was to confirm the average condition of the equipment as indicated by the condition data bases provided to Kinectrics.

Scope of the Work

The project includes the following:

1. Provide Recommended Health Index formulations used to derive Health Indices
2. Calculate and provide Health Index distribution for each of the aforementioned asset categories
3. Provide Capital Replacement Plan
4. Identify condition data gaps and provide recommendations for their prioritized closure

These areas and the factors of assessments covered under this project, are based on Kinectrics experience and familiarity with the industry requirements, and provides rational for the capital replacement expenditures being sought by NPEI. As such, the results will help NPEI in its service rate application submission to the OEB and will provide a basis for a medium to long-term capital plan for its distribution assets. It is worth noting, however, that replacement requirement due to poor asset condition is not the only basis for developing a capital plan: other factors, such as obsolescence, design flaws, exposure to severe environmental conditions, system requirements, etc. should also be taken into account when developing such plan.

Visual field inspection was conducted at several locations and included:

- 3 locations of three-phase pad mounted transformers
- 2 locations of overhead switches
- 5 locations of wood poles
- 2 locations of pole mounted transformers,
- 1 location of pad mounted switchgear
- 2 locations of distribution station transformers.

All of the locations were inspected directly by Kinectrics staff that traveled to the sites accompanied by a NPEI employee. The sample locations were scattered at 11 geographic areas within the service territory of NPEI.

Deliverables

The deliverables in this report include the following information:

- Short description of the asset groups being considered in the study
- Discussion of asset degradation and end-of-life issues
- Health Index results for the Asset Groups
- Description of methodology for assessment of asset replacements
- Capital replacement plan
- Data Gap Closure
- Field inspection results

B ASSET CONDITION ASSESSMENT METHODOLOGY

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Health Indexing

Health Indexing quantifies equipment condition based on numerous condition criteria that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index (HI) is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing differs from maintenance testing, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition Parameters are the asset characteristics that are used to derive the Health Index. In formulating a Health Index, condition parameters are ranked and evaluated, through the assignment of corresponding weights, based on their contribution to asset degradation. The condition parameter score is an evaluation of an asset with respect to a condition parameter.

A condition parameter may also be comprised of several sub-condition parameters. For example, a parameter called "insulation" for power transformers may be a composite of Oil Quality and Oil DGA.

The Health Index, which is a function of the condition parameter scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)}$$

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)

While weightings are assigned based on the priority level of condition parameters, scores represent the evaluation of an asset against condition criteria. A condition criterion is the scale that is used to determine an asset's score for a particular parameter.

Consider, for example, a system where the Health Index is described under one of the following five categories: very poor, poor, fair, good, and very good. A scoring system of 0 through 4 corresponds to the "very poor" through "very good" categorization. Consider a parameter "age" for which this scoring system is applied. The condition criteria will define the age that constitutes scores of 0 through 4 (i.e. a pole mounted transformer that is 50 years old will receive a score of 0; whereas one that is 2 years old will receive the maximum score of 4). Note that in this study, the condition criteria scoring system consist of values from zero (0) through four (4), with 0 being the worst and 4 being the best score.

De-rating factors are also used to adjust a calculated Health Index to reflect certain conditions. These may be factors that may or may not be related to asset condition, but contribute to the asset's risk of failure. For example, an air-insulated Pad Mounted Switchgear by a major roadway is prone to problems. Dominant parameters may be used as de-rating factors. These are asset properties that are considered to be of such importance that its status has a dominant impact on the value of the Health Index. De-rating factors are used to reduce the Health Index of an asset by a certain percentage. If a calculated Health Index is, say, 90%, a de-rating factor of 80% will reduce the effective Health Index to 90% x 80% = 72%.

Relating Health Index to Effective Age

Once the Health Index of an asset is determined, its *effective age* can be evaluated by establishing a relationship between its Health Index and its probability of failure. Effective age is different from chronological age in that it is based on the asset's condition and the stress stresses applied to the asset.

Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. The failure rate equation is in the form of:

$$f = e^{\beta(t-\alpha)}$$

where

f	= failure rate of an asset (frequency or the number of expected failures per year) at time t
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding probability of failure is given as:

$$P_f = 1 - e^{-(f - e^{\alpha\beta})/\beta}$$

where

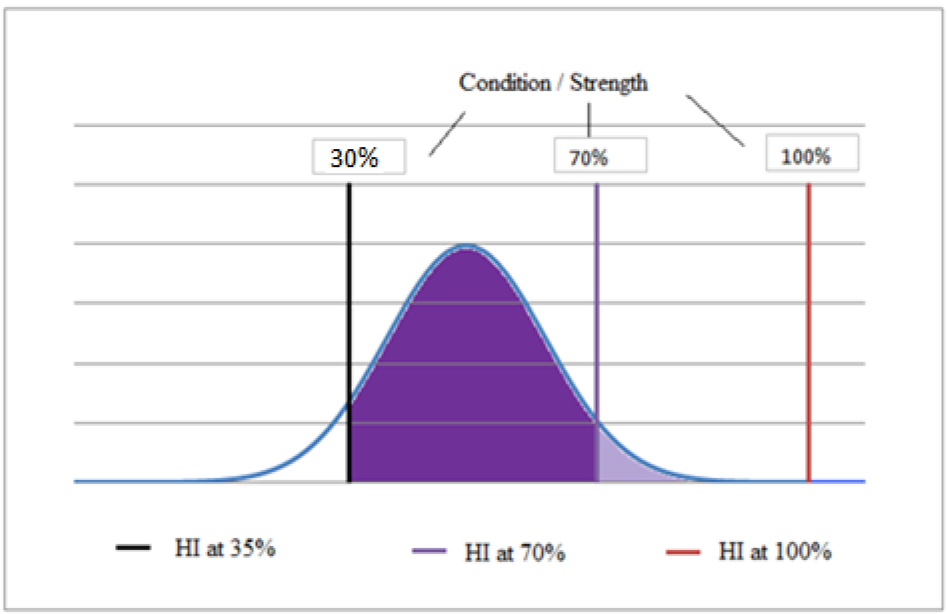
P_f	= probability of failure
f	= failure rate of an asset
α, β	= constant parameters that control the rise of the curve

Different assets groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used control the location and steepness of the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Quantitative Relationship Between Health Index and Probability of Failure

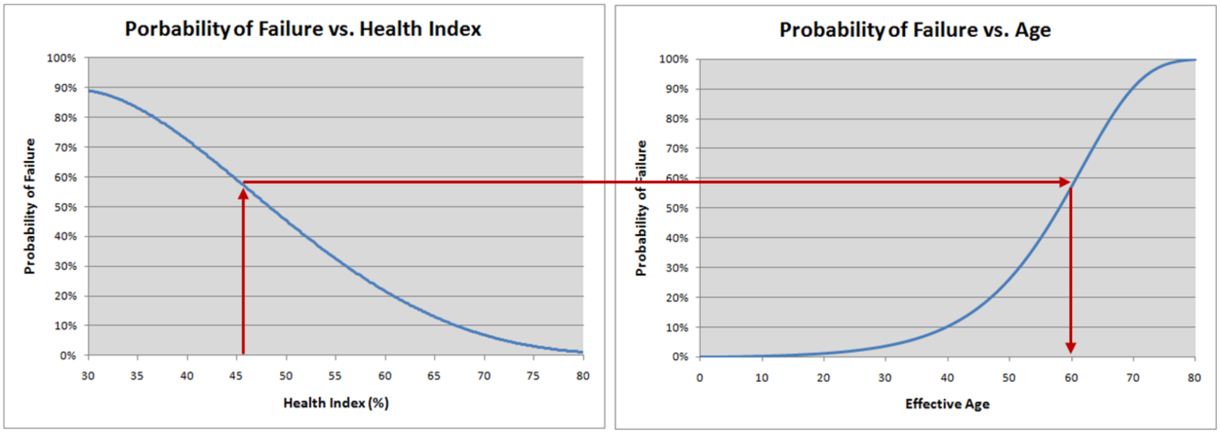
Failure of an asset occurs when the stress that an asset experiences exceeds is strength. Assuming that stress is not constant and the stress probability is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure.

Consider the Health Index to be a representation of condition. Two Health Index points and the probabilities of failure at those Health Index points can be used to find the probabilities of failure at other Health Index values. This is illustrated in the figure below. The vertical line represents condition (Health Index) and the area under the curve to the right of the line represents the probability of failure.
A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 30% at its end of life. Moving the vertical line left from 100% to 30%, the probabilities of failure at other Health Indices can be found.



Effective Age and Remaining Life

The effective age associated with a particular Health Index is found by first plotting the Probability of Failure vs. Health Index curve. This is the area under the probability density curve between the 100% and 30% Health Index points. This curve is shown on the left hand graph of the figure below. The associated probability of failure is then found on Probability of Failure vs. Age graph (right hand graph). The effective age is read from the horizontal axis of the right hand graph.



Relationship between Health Index and Effective Age

The remaining life can be estimated as the difference between the asset's maximum life expectancy and its effective age. For example, a pole mounted transformer that has an effective age of 35 years will have a remaining life of 45-35 = 10 years.

Capital Replacement Plan

Simple Replacement

Asset groups that have little consequence of failure or that are run to failure are reactively replaced. The number of predicted failures multiplied by the replacement cost per unit at the year of failure determined the yearly investments for the asset group.

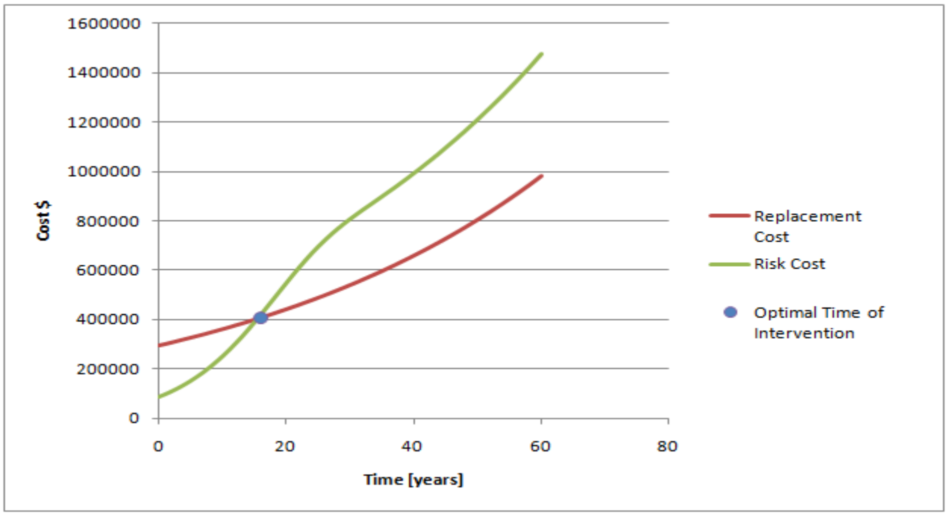
Risk Analysis

For assets that are have a high consequence of failure (i.e. power transformers), risk analysis determined the economic optimal time of intervention. Planned replacement cost, cost of failure, and risk cost were considered.

The utility's *costs of failure* for an asset can include the replacement cost of the asset, any collateral damage to adjacent equipment, environmental clean-up costs, overtime labour premiums, and the lost revenue. Some utilities also include the cost of interruptions to customers. For this analysis, the cost of failure was estimated as a multiple of its planned replacement cost. For non-critical power transformers, the cost of failure was defined as 1.5 times the planned replacement cost, whereas for critical power transformers, the cost of failure multiple was 2.

The *risk cost* is defined as the failure cost times the probability of failure, probability of failure is dependent on an asset's effective age.

The optimal time of intervention (refurbishment or replacement) was found as the point where the risk cost begins to exceeds the replacement cost. The number of units that were flagged for replacement in a given year times replacement cost for the given year determined the investment required for that year.



Data Gap Closure

Prioritized strategy for data gap closure is included for each asset category using 3 priority levels, from the highest (3 stars) to the lowest (a single star). It is recommended to start collecting condition data for the highest priority condition parameters as this will improve credibility of the Health Index results the most. This is the case for both assets with some condition data available and assets with no condition data available.

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C RESULTS AND FINDINGS

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1 Power Transformers

The application of substation station transformers generally involves the step down of a higher to lower voltage. Power transformers vary in capacity and ratings over a broad range.

Station transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary, secondary and, possibly, tertiary windings
- Laminated iron core
- Internal insulating media
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

1.1 Degradation Mechanism

For a majority of transformers, End-of-Life (EOL) is expected to be caused by the failure of the insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture.

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units with a probable high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for substation transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no-load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonic and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for substation transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles
- Maximum loading profile

1.1.1 *Failure Mechanism of Station Transformers*

1.1.1.1 Thermal Aging:

Thermal aging involves the progress of chemical and physical changes because of chemical degradation reactions, polymerization, depolymerization, and diffusions.

1.1.1.2 Electrical Aging:

Electrical aging, as it relates to AC, impulse, or switching involves the effects of the following:

- partial discharges
- treeing
- electrolysis
- increased temperatures produced by high dielectric losses
- space charges

1.1.1.3 Mechanical Aging

Mechanical aging involves the following:

- fatigue failure of insulation components caused by a large number of low-level stress cycles
- thermo mechanical effects caused by thermal expansion and or contraction
- rupture of insulation by high levels of mechanical stress such as may be caused by external forces or operation condition of the equipment
- Insulation creep or flow under electrical, thermal, or mechanical stresses

1.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DF$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF_n} \times \mathrm{WCPF_n})}{\sum_{n=1} \beta_n (\mathrm{CPF_{n.max}} \times \mathrm{WCPF_n})} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter
DF --- De-rating Factor

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

1.3 Condition and Sub-Condition Parameters

Table 1-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Insulation	4	4
2	Sealing & Connection	1	4
3	Service record	3	4

Table 1-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	4	4
2	Oil DGA	5	4

1.3.1 *Oil Quality*

Table 1-3 Oil Quality Test

Condition Rating	CPF	Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

Table 1-4 Oil Quality Overall Factoring

		Scores				
		1	2	3	4	Weight
Dielectric Str. kV D877		>40	>30	>20	Less than 20	3
IFT* dynes/cm	230 kV $\leq$ U	>32	25-32	20-25	Less than 20	2 *
	69 kV <U< 230	>30	23-30	18-23	Less than 18	
	U $\leq$ 69 kV	>25	20-25	15-20	Less than 15	
Color		Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number*	230 kV $\leq$ U	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <U< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	U $\leq$ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

1.3.2 *Oil Dissolved Gas Analysis (DGA)*

Table 1-5 Transformer DGA

Condition Rating*	CPF	Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

*In the case of a score other than A, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score B, 0.85 for score C, 0.75 for score D and 0.5 for score E.

Where the DGA overall factor is the weighted average of the following gas scores:

Table 1-6 Oil DGA Overall Factoring

	Scores						
	1	2	3	4	5	6	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	1
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	1

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Table 1-7 Sealing & Connection (m=2) Weights and Maximum CPF

n	**Sub-Condition Parameter**	**$WCPF_n$**	**$CPF_{n.max}$**
1	Tank Oil Leak	1	4
2	Conservator Oil Level	1	4

Table 1-8 Service Record (m=3) Weights and Maximum CPF

n	**Sub-Condition Parameter**	**$WCPF_n$**	**$CPF_{n.max}$**
1	Age	1	4

1.3.3 *Age*

Table 1-9 Transformer Age

Condition Rating	**CPF**	**Description**
A	4	0-19
B	3	20-29
C	2	30-44
D	1	45-54
E	0	>=55

1.4 Health Index Results

The total population of assets for this category is 23. The Sample Size or total number of assets within the population that have data is 23, which means there was data for each asset.

The year purchased was assumed to the transformers age. There was full data for Oil dissolved gas analysis (DGA). It is recommended that data be collected on moisture ppm, power factor (for winding doble score), as well as collecting data on grounding and IR thermography.

The Health Indexing Result by Unit and Percentage are presented below:

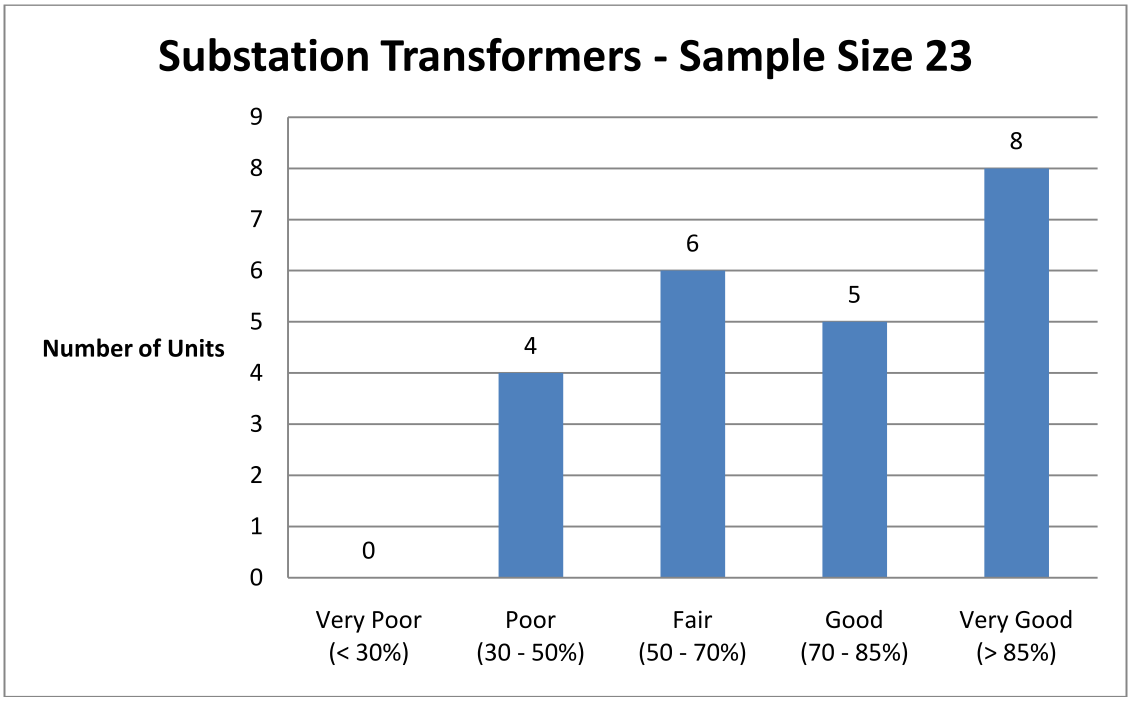

Figure 1-1 Health Index Distribution by Units

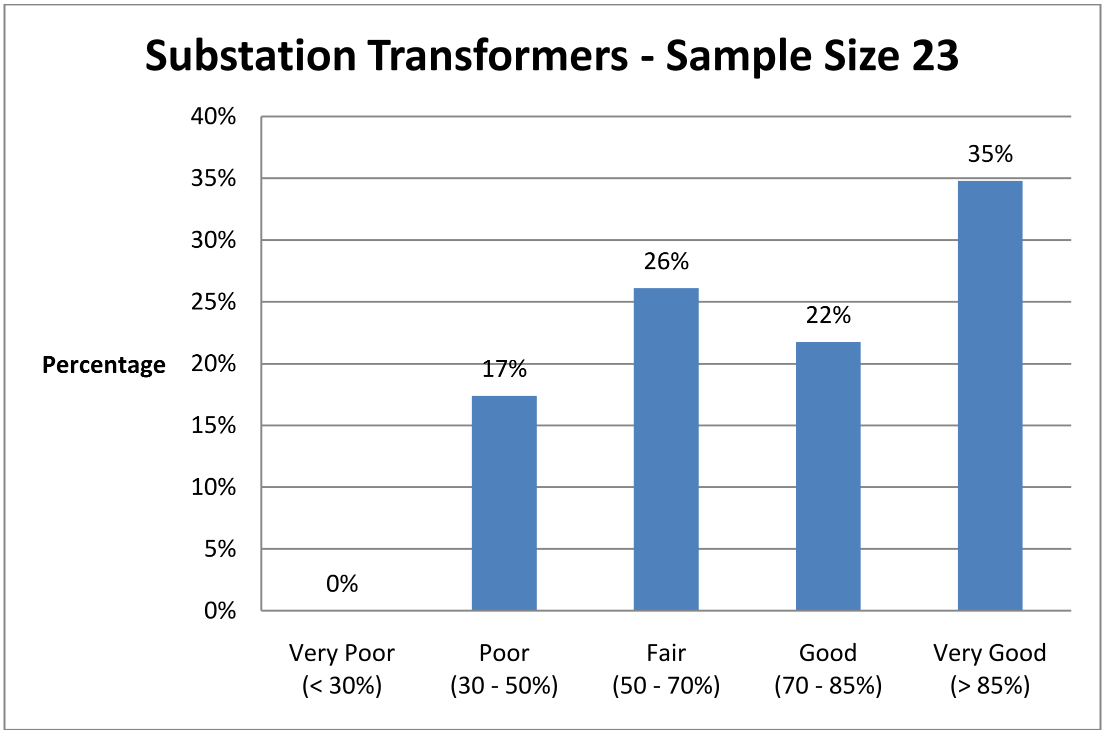

Figure 1-2 Health Index Distribution by Percentage

The exact rating for each Transformer is presented below:

Table 1-10 Substation Health Index Score and Criticality

Transformer No	Substation Name	HI Score	HI Rating	Critical
SD71844-3	SMITHVILLE DS - NF1844	38%	POOR	YES
SD1856-T2	GREEN LANE D.S. - NF 1856	43%	POOR	YES
SD71844-1	SMITHVILLE DS - NF1844	50%	POOR	YES
SD71844-2	SMITHVILLE DS - NF1844	50%	POOR	YES
SD1856-T1	GREEN LANE D.S. - NF 1856	56%	FAIR	YES
800089	VIRGINIA A-144	59%	FAIR	NO
800095	MARGARET A-127	61%	FAIR	YES
800073	ARMOURY A-113	61%	FAIR	NO
800084	ALLENDALE A-175	69%	FAIR	NO
SD1850	CAMPDEN D.S. - NF 1850	69%	FAIR	YES
SD001	STATION ST. D.S.	74%	GOOD	NO
800100	O'NEIL A-148	81%	GOOD	NO
800082	ALLENDALE A-175	81%	GOOD	NO
800295	LEWIS A-119	78%	GOOD	NO
800077	ONTARIO A-115	78%	GOOD	NO

800389	DRUMMOND A-122	86%	VERY GOOD	NO
800052	PARK A-33	86%	VERY GOOD	NO
800054	VIRGINIA A-144	88%	VERY GOOD	NO
2515T2	KALAR TS	93%	VERY GOOD	NO
800388	PEW A-135	93%	VERY GOOD	NO
800053	SWAYZE A-145	100%	VERY GOOD	NO
2515T1	KALAR TS	100%	VERY GOOD	NO
SD1836	JORDAN D.S. - NF 1836	100%	VERY GOOD	YES

1.5 Field Inspection Results

Four Power Transformers were inspected. The data can be found in Section E FIELD INSPECTION FORMS and the summary is shown in Figure 1-3 below. There were no major concerns with the units inspected.

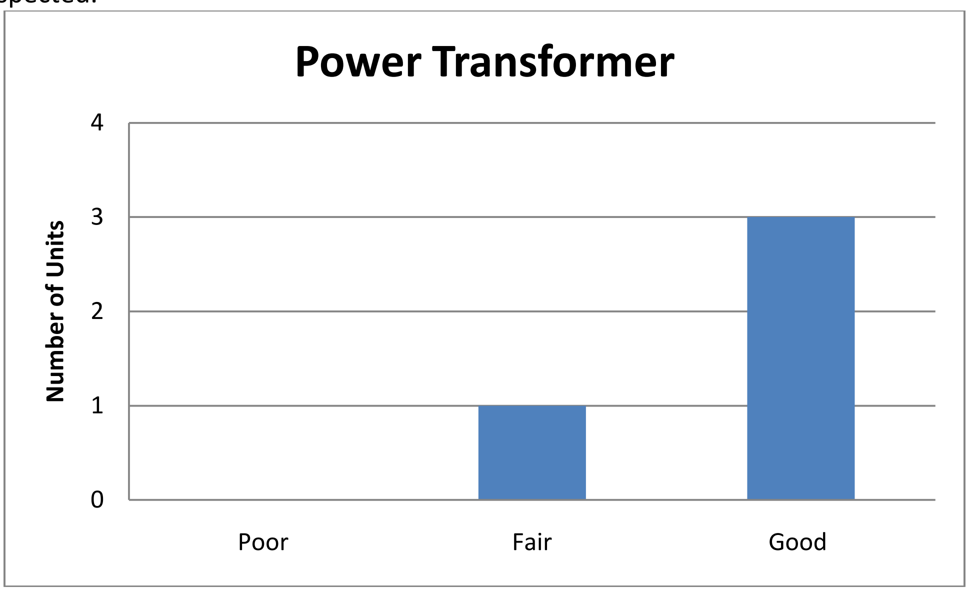

Figure 1-3 Field Inspection Results

1.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 25 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

1.6.1 *Optimal Capital Replacement Plan*

Figure 1-4 shows the number of Transformer units that will need to be replaced over the next 20 years for the whole population extrapolated from the results for the sample with adequate condition data. Given the full sample size (100%) the recommendations are for the entire population.

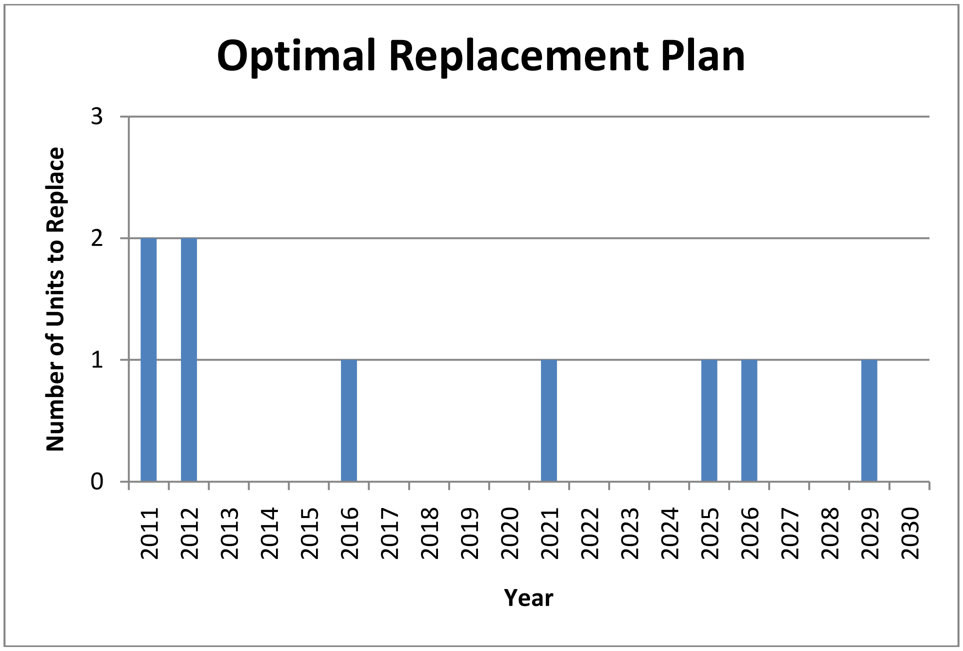

Figure 1-4 Optimal Replacement Plan

1.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 2 units in the next year. While this is optimal based on NPEI's Power Transformers HI scores, it may not be ideal financially.

Power Transformers are replaced **proactively**. The Levelized replacement plan allows for Transformers that would optimally be replaced in one year to be replaced over a period of time in the future.

Figure 1-5 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

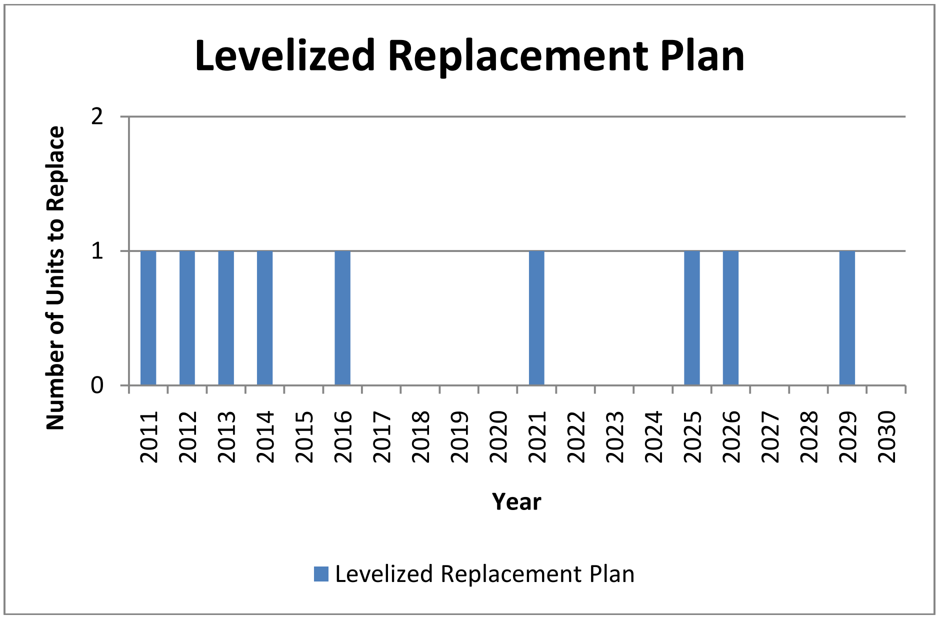

Figure 1-5 Levelized Replacement Plan

1.7 Data Gap Closure

The following table summarizes the data gap for power transformers in this project.

Table 1-11 Data Gap Closure

Sub-system	Condition Parameter	Data Collection Priority
Insulation	Winding Doble	☆☆
Cooling	Temperature	☆☆
Sealing & connection	Grounding	☆
	IR thermography	☆☆☆
Service record	Loading	☆☆

IR thermography is a useful approach in detecting hot spots due to a loose connection or leakage. In this project, it also can address the temperature issue in cooling system as well as the transformer loading status, when the data on those 2 parameters are unavailable.

In the sub-system of insulation, another parameter “oil quality” indirectly addresses the winding insulation deterioration, as it detects on some contents that are the consequence of insulation deterioration (moisture, oxygen due to cellulose degradation).

2 Large Pad Mounted Transformers

Pad Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure. Large Pad Mounted Transformers are Pad Mounted Transformers greater than 700 kVA.

2.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

2.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DF$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter
DF --- De-rating Factor

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

2.3 Condition and Sub-Condition Parameters

Table 2-1 Condition Weights and Maximum CPS

M	Condition parameter	WCP_m	$CPS_{m.max}$
1	Insulation	4	4
2	Sealing & Connection	1	4
3	Service Record	3	4

Table 2-2 Insulation (m=1) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	4	4
2	Oil DGA	5	4

2.3.1 *Oil Quality*

Table 2-3 Oil Quality Test

Condition Rating	CPF	Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

Table 2-4 Oil Quality Overall Factoring

		Scores				
		1	2	3	4	Weight
Dielectric Str. kV D877		>40	>30	>20	Less than 20	3
IFT* dynes/cm	230 kV ≤ U	>32	25-32	20-25	Less than 20	2 *
	69 kV <U< 230	>30	23-30	18-23	Less than 18	
	U ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color		Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number*	230 kV ≤ U	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <U< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	U ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

2.3.2 *Oil Dissolved Gas Analysis (DGA)*

Table 2-5 Transformer DGA

Condition Rating*	CPF	Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

*In the case of a score other than A, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score B, 0.85 for score C, 0.75 for score D and 0.5 for score E.

Where the DGA overall factor is the weighted average of the following gas scores:

Table 2-6 Oil DGA Overall Factoring

	Scores						
	1	2	3	4	5	6	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	1
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	1

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Table 2-7 Sealing & Connection (m=2) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Tank Oil Leak	1	4
2	Conservator Oil Level	1	4

Table 2-8 Service Record (m=3) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Age	1	4

2.3.3 *Age*

The age used was based on the manufacture date on the name plate of the transformer.

Table 2-9 Transformer Age

Condition Rating	CPF	Description
A	4	0-19
B	3	20-29
C	2	30-44
D	1	45-54
E	0	>=55

2.4 Health Index Results

The total population of assets for this category is 56. The Sample Size or total number of assets within the population that have data is 51.

The Health Indexing Result by Unit and Percentage are presented below:

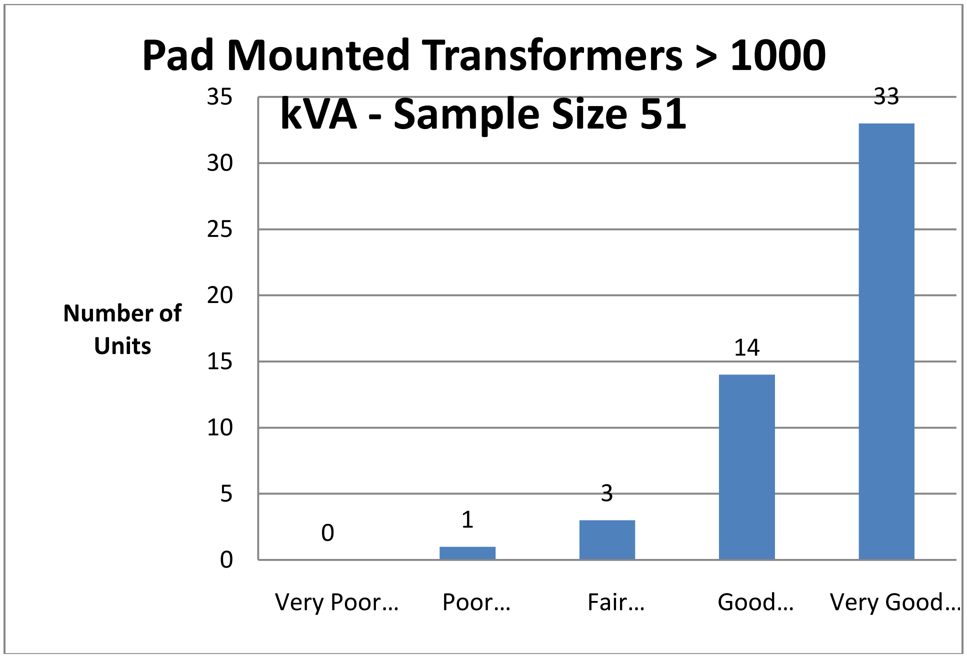

Figure 2-1 Health Index Distribution by Units

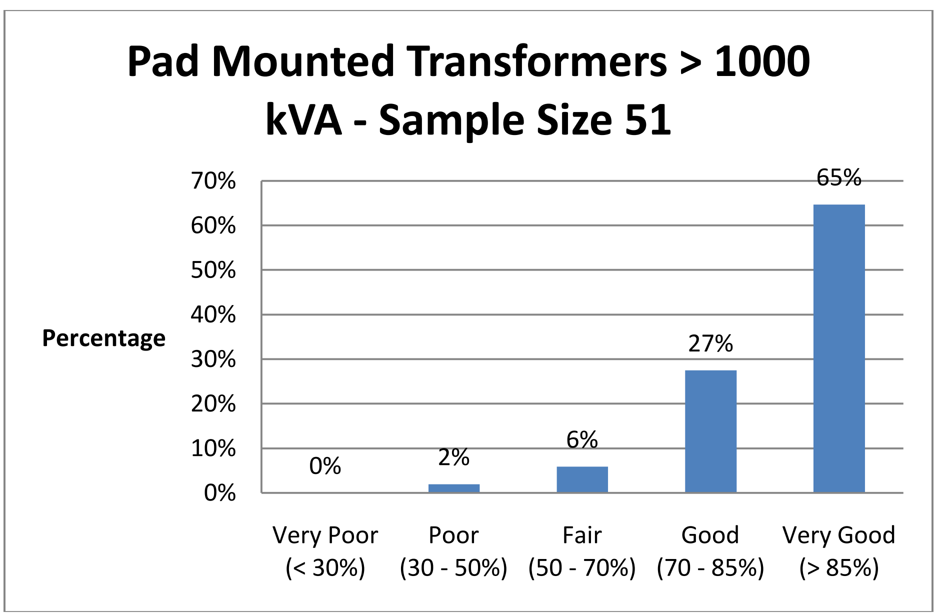

Figure 2-2 Health Index Distribution by Percentage

The exact rating for each Transformer is presented below:

Table 2-10 Pad Mounted Transformer Health Index Score

Transformer No	Substation Name	HI Score	HI Rating
800135		50%	POOR
	SMITHVILLE 85	60%	FAIR
800105		63%	FAIR
732	FROST ROAD	69%	FAIR
2529		75%	GOOD
800515	DOUBLE TREE	75%	GOOD
800109		78%	GOOD
	NO NAMEPLATE	80%	GOOD
800554		81%	GOOD
800129	STATION 52	81%	GOOD
800128	STATION 52	81%	GOOD
800197		81%	GOOD
800148	HEDGSON	81%	GOOD
800127	DAYS INN FALLVIEW	81%	GOOD
800210	MANSIONS OF FOREST GLEN	81%	GOOD
800116	BUCKLEY TOWER	81%	GOOD
800126		84%	GOOD
77045	INDUSTRIAL PARK	86%	VERY GOOD
800526	DAYS INN VICTORIA AVE	86%	VERY GOOD
494	HILLSIDE DRIVE (5050)	86%	VERY GOOD
3040	SOUTH SERVICE RD	88%	VERY GOOD
800413	SUPER 8	90%	VERY GOOD
9201	BARTLETT ROAD (4306)	91%	VERY GOOD
3176	4927 ONTARIO ST.	91%	VERY GOOD
1652	SECOND AVE	93%	VERY GOOD
800568		93%	VERY GOOD
800546	NF COMM CENTRE	93%	VERY GOOD
800587		93%	VERY GOOD
800430	SWAGELOK	100%	VERY GOOD
800465		100%	VERY GOOD
301	4655 BARTLETT	100%	VERY GOOD
546	4927 ONTARIO ST.	100%	VERY GOOD
800550	NIAGARA REGION	100%	VERY GOOD
800601		100%	VERY GOOD
599	ONTARIO ST (SOBEYS)	100%	VERY GOOD
800589		100%	VERY GOOD
73201	PEARSON STREET	100%	VERY GOOD

81	FROST ROAD	100%	VERY GOOD
8099	4758 CHRISTIE ST.	100%	VERY GOOD
629	TWENTY THIRD ST	100%	VERY GOOD
800414	TGI FRIDAYS	100%	VERY GOOD
202	JORDAN ROAD	100%	VERY GOOD
800532		100%	VERY GOOD
800585		100%	VERY GOOD
800443	NPE BUILDING	100%	VERY GOOD
83005	REGIONAL ROAD 20 EAST	100%	VERY GOOD
800586		100%	VERY GOOD
800490	GOLDEN HORSESHOE	100%	VERY GOOD
800584		100%	VERY GOOD
800588		100%	VERY GOOD
99121	NORTH SERVICE RD	NO DATA	
800147	EVENTIDE HOME	NO DATA	
229	DURHAM ROAD	NO DATA	

2.5 Field Inspection Results

Field inspections were only done on Standard Pad Mounted Transformers.

2.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 25 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

2.6.1 *Optimal Capital Replacement Plan*

Figure 2-3 shows the number of Transformer units that will need to be replaced over the next 20 years for the whole population extrapolated from the results for the sample with adequate condition data. Given a significant sample size (93%) there is a high degree of confidence that the recommendations for the sample and the whole population are the same.

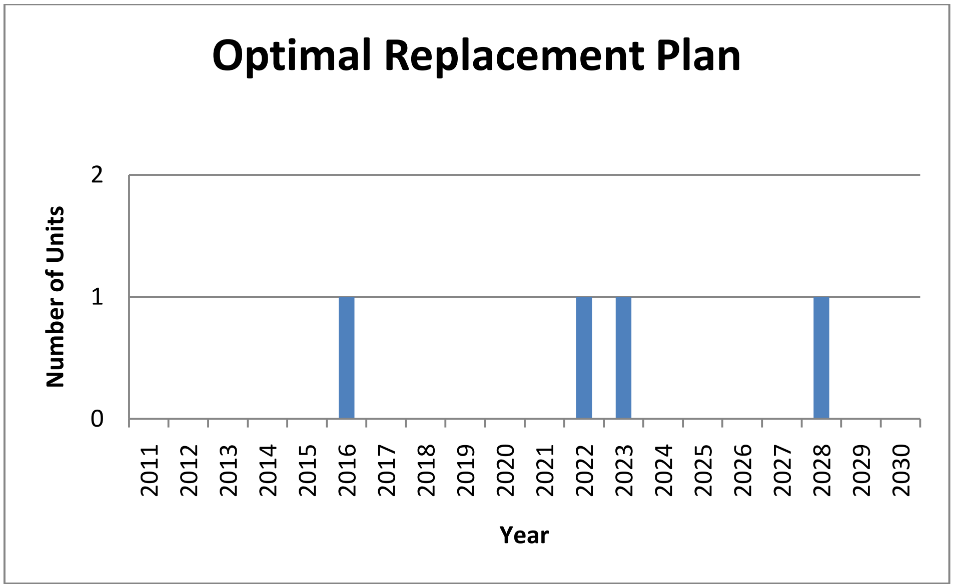

Figure 2-3 Optimal Replacement Plan

2.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing no units in the next 5 years. There are no peaks in replacement years.

Large Pad Transformers are replaced **proactively**. The Levelized replacement plan allows for Transformers that would optimally be replaced in one year to be replaced over a period of time.

Figure 2-4 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time, it is the same as the optimal replacement plan.

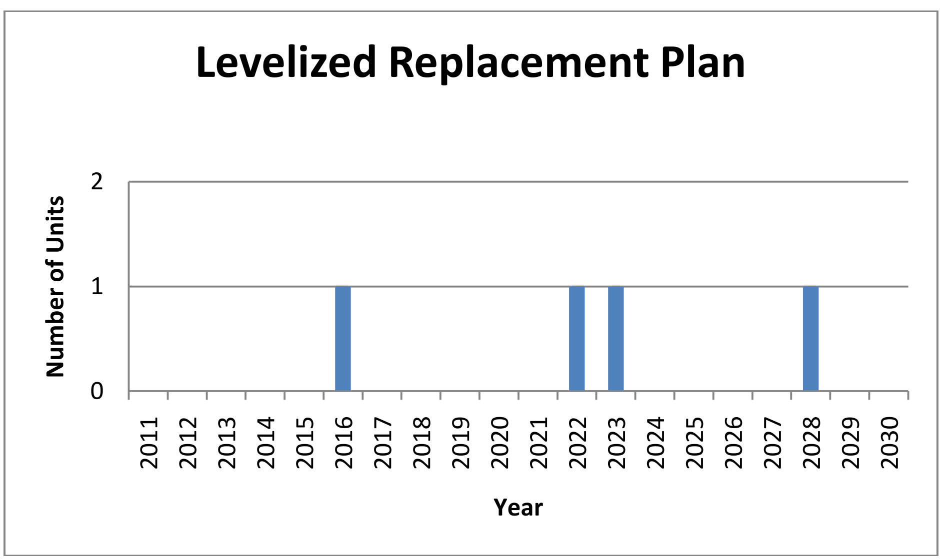

Figure 2-4 Levelized Replacement Plan

2.7 Data Gap Closure

The following table summarizes the data gap for large pad mounted transformers in this project.

Sub-system	Condition	Data Collection Priority
Sealing & connection	Grounding	✯
	IR thermography	✯ ✯ ✯
Service record	Loading	✯ ✯
	Age	✯ ✯

IR thermography is a useful approach in detecting hot spots due to a loose connection or leakage. In this project, it also can address the transformer loading status, when the data on such parameter are unavailable.

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3 Standard Pad-Mounted Transformers

Pad Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure. Standard Pad Mounted Transformers are smaller than 750 kVA.

3.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

3.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

3.3 Condition and Sub-Condition Parameters

Standard Pad Mounted Transformers that are base type **Collar** are **de-rated** to **30%** of the calculated Health Index Value.

Table 3-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical condition	3	4
2	Connection & insulation	5	4
3	Service record	5	4
4	Testing	10	4

Table 3-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Access (ok/not ok)	1	4

Table 3-3 Connection & insulation (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Oil contamination (ok/not ok)	2	4
2	Grounding	1	4
3	Insulator (ok/not ok)	4	4
4	Enclosure	1	4

Table 3-4 Testing (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	IR Scan (Pass/Fail)	1	4
2	Ultra Sound (Pass/Fail)	1	4

3.3.1 *Enclosure*

Table 3-5 Enclosure Rating Score

ENCLOSURE

Condition Rating	CPF	Condition Description
A	4	Good
B	3	Graffiti
C	2	Needs Repainting
D	0	Rusting
E	0	Rusting and Graffiti
F	0	Rusting and Needs Repairs
G	0	Rusting and Needs Repainting

3.3.2 *Grounding*

Table 3-6 Grounding Rating Score

GROUNDING

Condition Rating	CPF	Condition Description
A	4	6
A	4	4
A	4	3
A	4	2
E	0	1
E	0	Other

Table 3-7 Service Record (m=3) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Inspection result	2	4
2	Age	1	4

3.3.3 *Age*

Table 3-8 Age Rating Score

Age		
Condition Rating	**Description**	**CPF**
A	0	4
B	24	3
C	30	2
E	40	0

3.4 Health Index Results

The total population of assets for this category is 2408. The Sample Size or total number of assets within the population that have data other than age is 716.

The Health Indexing Result by Unit and Percentage are presented below for both the population of 716 (age and other data):

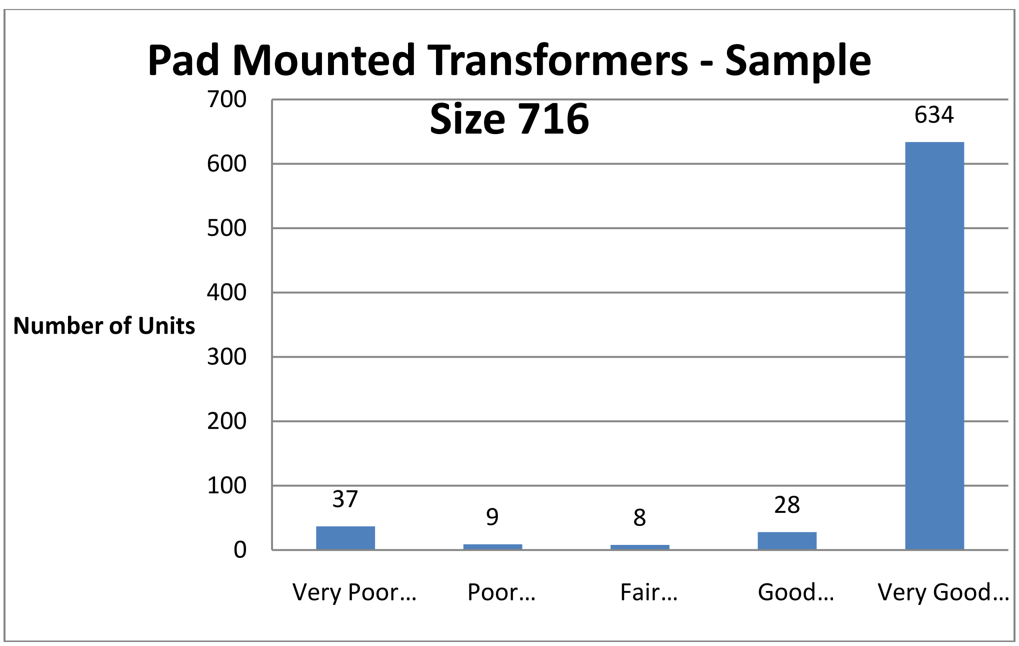

Figure 3-1 Health Index Distribution by Unit

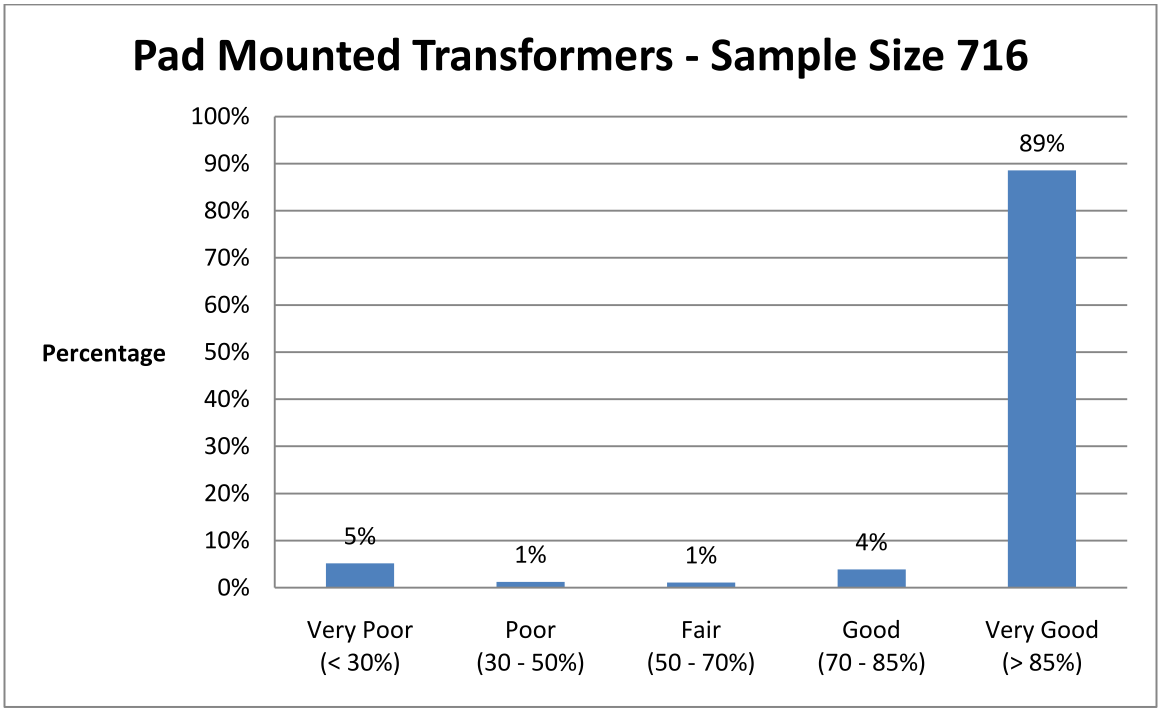

Figure 3-2 Health Index Distribution by Percentage

3.5 Field Inspection Results

Five Standard Pad Mounted Transformers were inspected. The data can be found in Section E FIELD INSPECTION FORMS and the summary is shown in Figure 3-3 below. Most of the units were in good to fair condition. The unit in poor condition was rated this way because of Pad Condition, Main Cabinet Condition and Overall Condition.

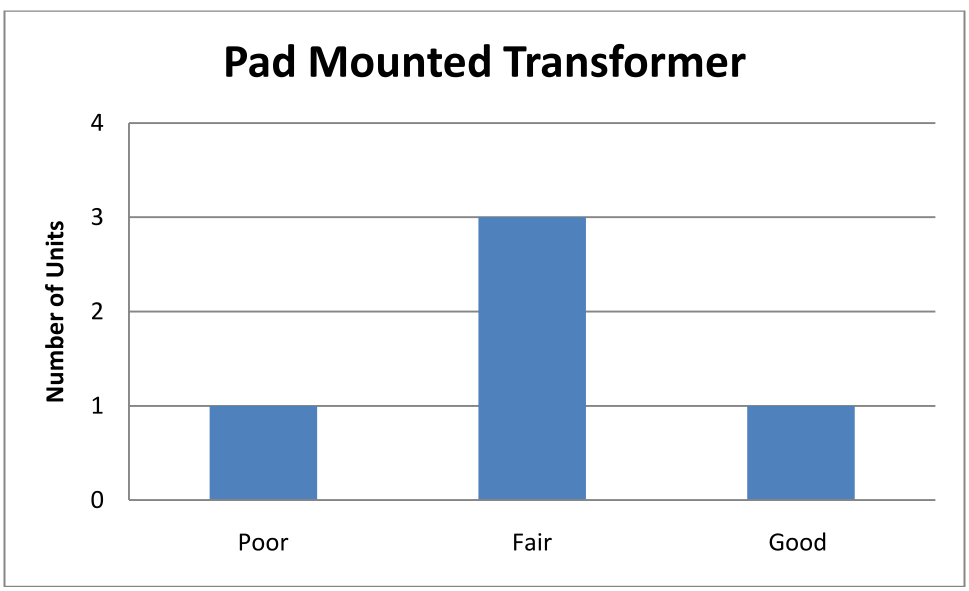

Figure 3-3 Field Inspection Results

The field inspection data indicates a different pattern than the sample case. This may be because only 30% of NPEI's were included in the Health Index sample (716 units) that may not represent NPEI's total population's Health Index.

3.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 25 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

3.6.1 *Optimal Replacement Plan*

Figure 3-4 the number of Transformer units that will need to be replaced over the next 20 years. The result was extrapolated from the 28% sample with more than just condition data available to the whole population. Since Health Index distribution based on age alone that was available for the whole population is similar to the sample's Health Index distribution, it appears that the sample was representative of the whole population.

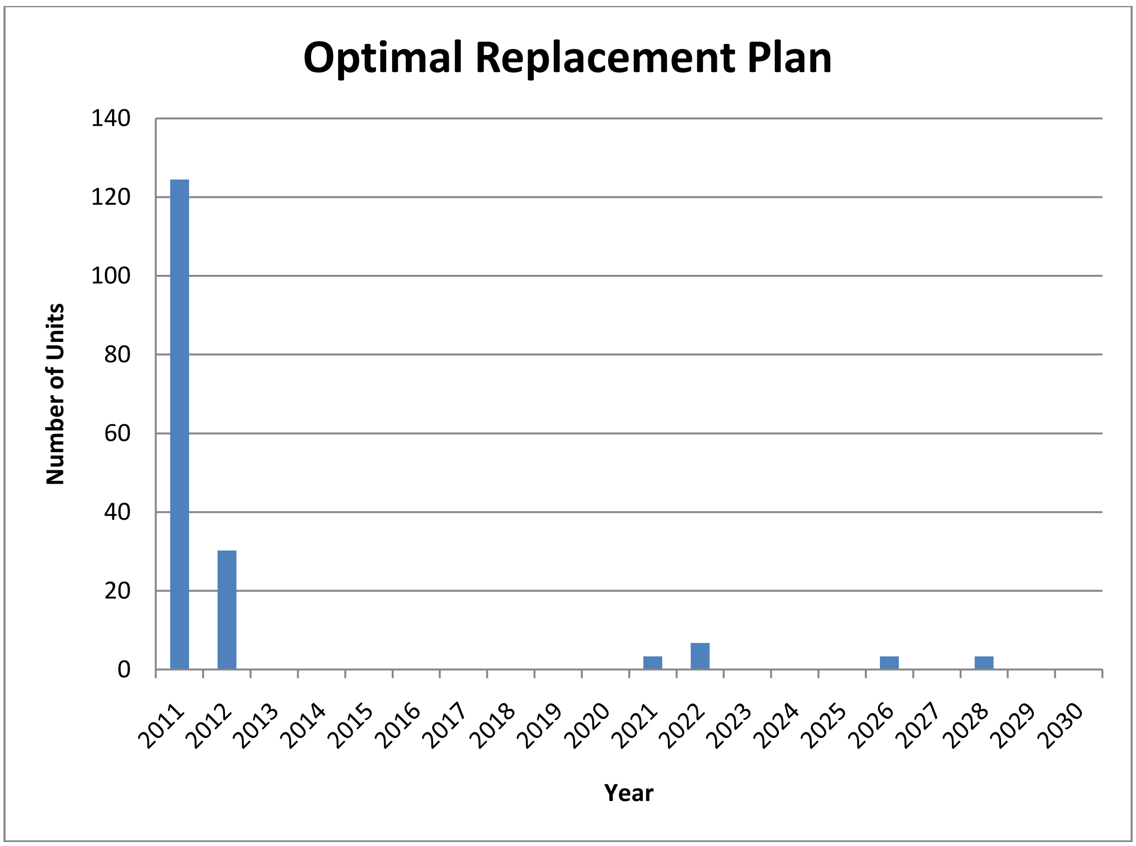

Figure 3-4 Optimal Replacement Plan

3.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 124 units in the next year. While this is optimal based on NPEI's Pad Mounted Transformers HI scores, it may not be ideal financially.

Standard Pad Transformers are typically replaced reactively (end of life.) However NPEI is replacing those transformers with collar type bases **proactively**. The Levelized replacement plan allows for Transformers that would optimally be replaced in one year to be replaced over a period of 5 years.

Figure 3-5 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

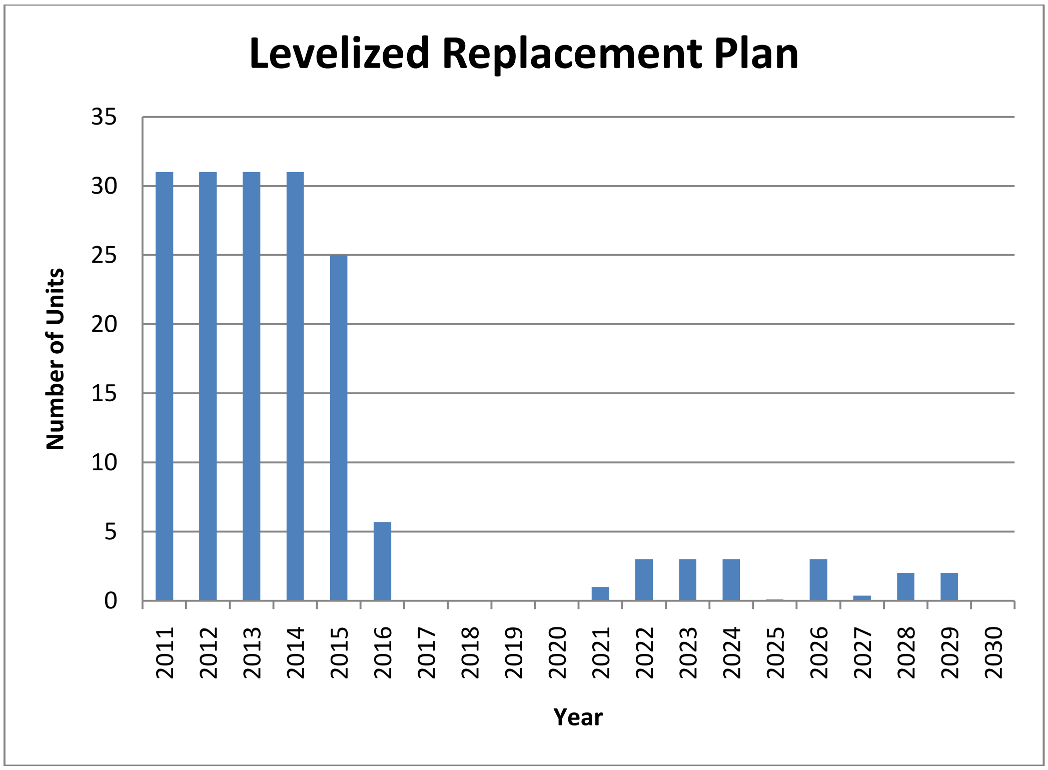

Figure 3-5 Levelized Replacement Plan

3.7 Data Gap Closure

The same information that has been collected for the sample needs to be collected for the remaining population.

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4 Pole-Mounted Transformers

Distribution pole top transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

4.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

4.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

4.3 Condition and Sub-Condition Parameters

Table 4-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Operating Practices	2	4
2	Service record	1	4

Table 4-2 Operating Practices (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Operating Practices	1	4

4.3.1 *Operating Practices*

Table 4-3 Customer Score Rating

CUSTOMERS		
Condition Rating	**Description**	**CPF**
A	0	4
B	10	3
C	20	2
E	40	0

Table 4-4 Service Record (m=2) Weights and Maximum CPF

N	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Age	1	4

4.3.2 *Age*

Table 4-5 Age Score Rating

Age		
Condition Rating	**Description**	**CPF**
A	0	4
B	24	3
C	30	2
E	40	0

4.4 Health Index Results

The total population of assets for this category is 6835. The Sample Size or total number of assets within the population that have data is 6711.

The year purchased was assumed to the transformers age. The other condition parameter was the number of customers serviced by the transformer.

The Health Indexing Result by Unit and Percentage are presented below:

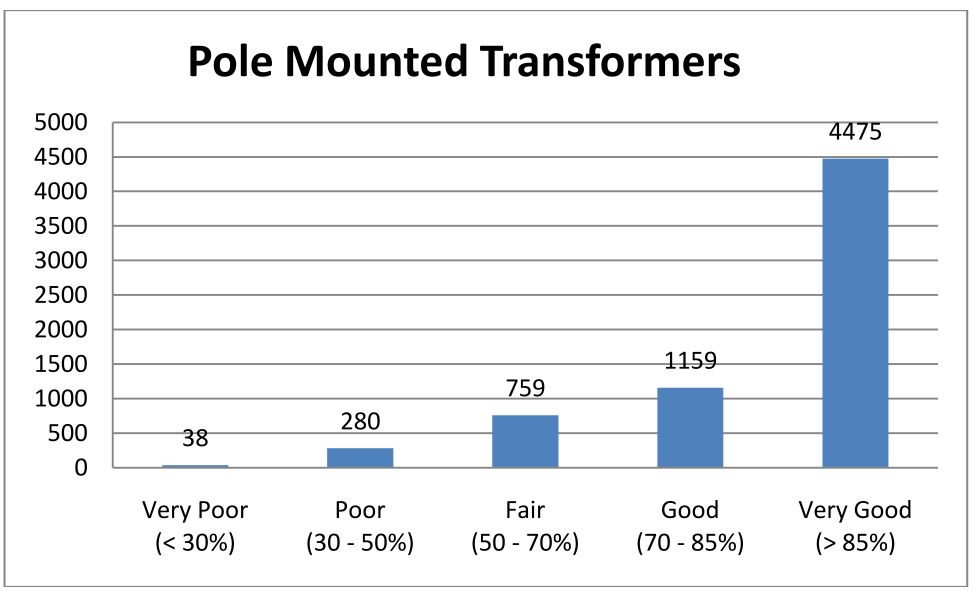

Figure 4-1 Health Index Distribution by Unit

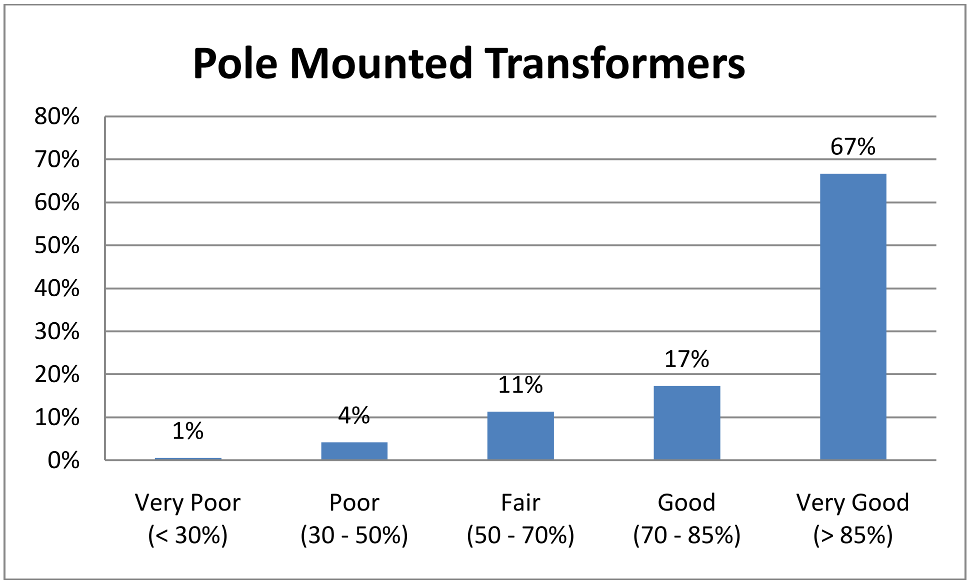

Figure 4-2 Health Index Distribution by Percentage

4.5 Field Inspection Results

Two Pole Mounted Transformers were inspected. The data can be found in Section E FIELD INSPECTION FORMS and are summarized in Figure 4-3 below. The units were in good and fair condition.

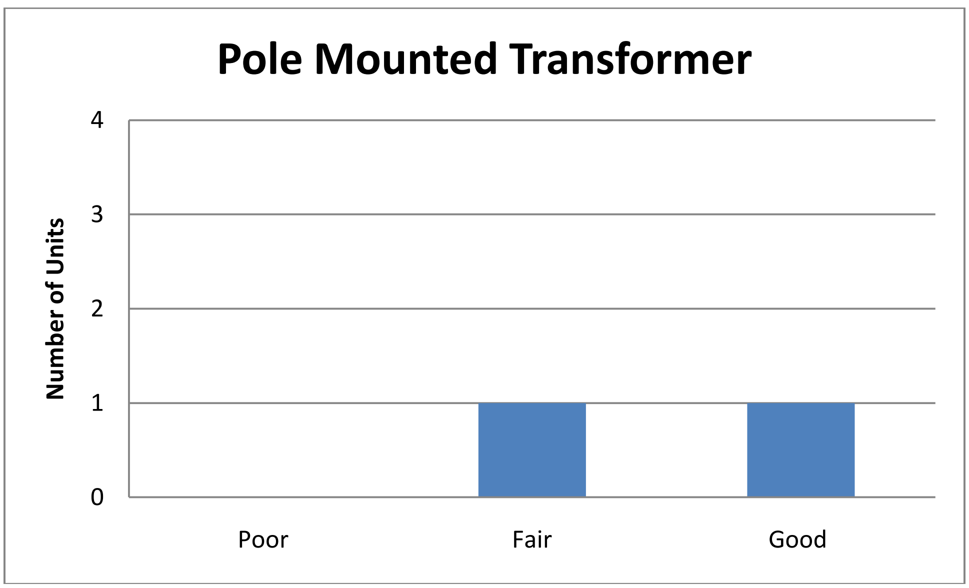

Figure 4-3 Field Inspection Results

4.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

4.6.1 *Optimal Replacement Plan*

Figure 4-4 shows the number of Transformer units that will need to be replaced over the next 20 years for the whole population extrapolated from the results for the sample with adequate condition data. Given a significant sample size (98%) there is a high degree of confidence that the recommendations for the sample and the whole population are the same.

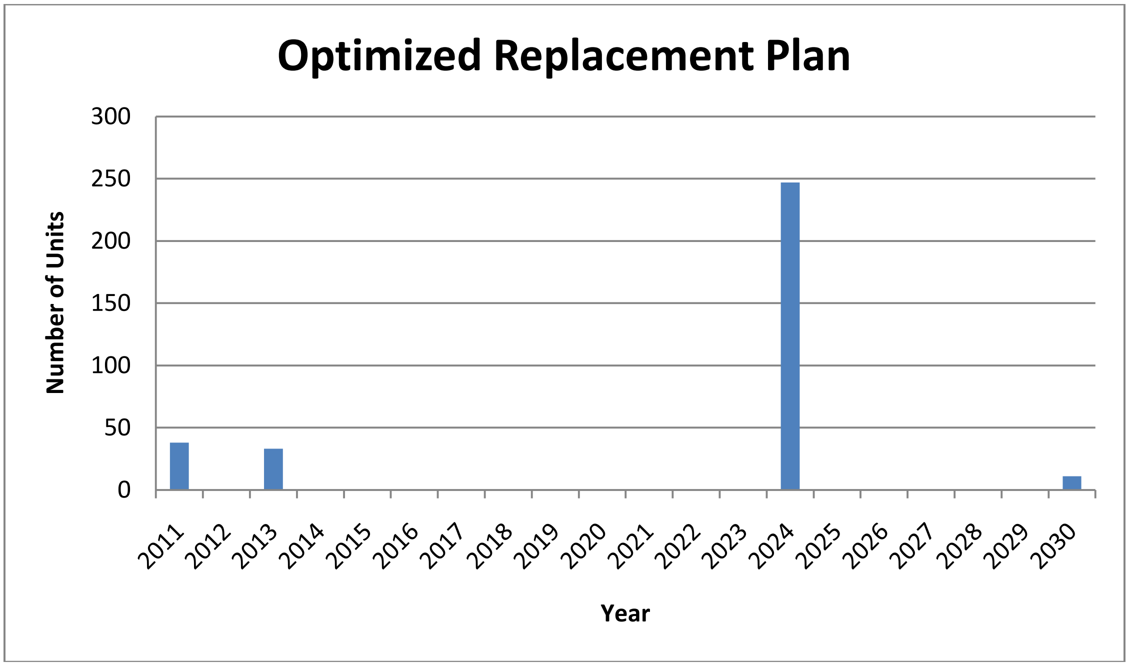

Figure 4-4 Optimal Replacement Plan

4.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 247 units in 2024. While this is optimal based on NPEI's Pole Mounted Transformers HI scores, it may not be ideal financially.

Pole Mounted Transformers are typically replaced **reactively** (end of life.) Since the HI scores indicate the majority of failures happening over the next 25 years, NPEI can take a Levelized approach by replacing assets before they are estimated to fail. The Levelized replacement plan allows for Transformers that would optimally be replaced in 2024 year to be replaced over a period of 5 years (2020-2024).

Figure 4-5 shows a Levelized capital replacement plan, where transformer replacements can occur over a longer period of time.

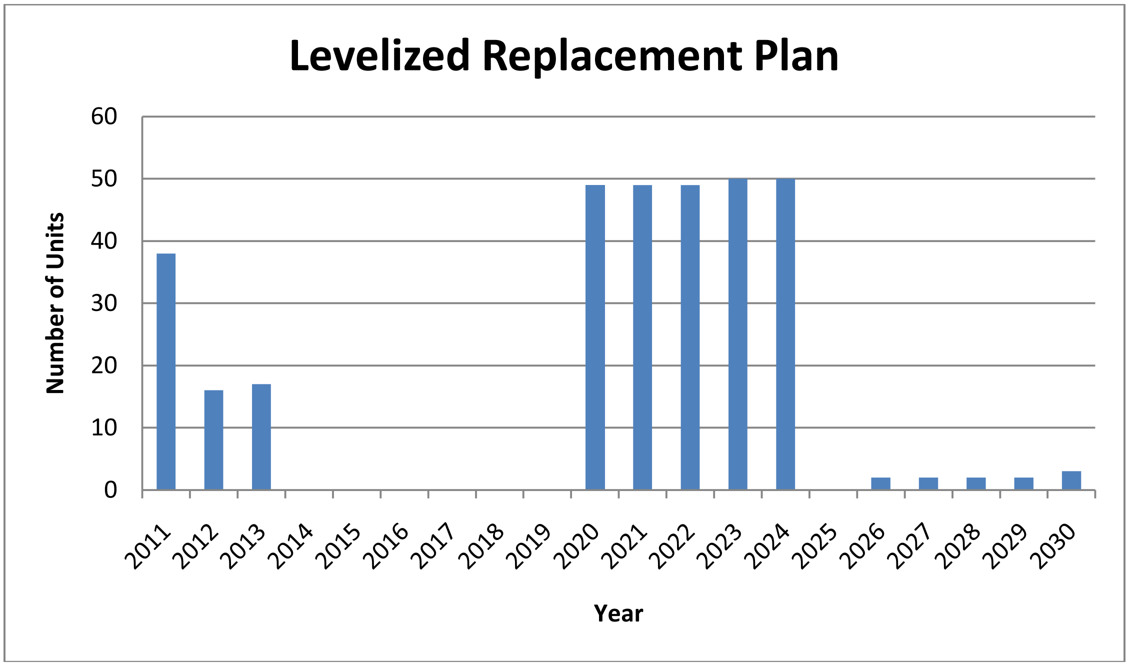

Figure 4-5 Levelized Replacement Plan

4.7 Data Gap Closure

The following table summarizes the data gap for pole mounted transformers in this project.

Sub-system	Condition Parameter	Data Collection Priority
Physical condition	Corrosion	☆ ☆
Connection & insulation	Oil leak	☆ ☆
Service record	Loading	☆ ☆ ☆

As a pole mounted transformer is a run-to-failure asset, its service record has much impact on its life cycle. While corrosion and oil leak provide visual inspection on the external signs of degradation, its loading history can be used to estimate its actual aging process.

5 Poles

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor & guys. The most important component with respect to useful life is the pole itself.

5.1 Degradation Mechanism

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on the electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow to identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

There are many factors considered by utilities when establishing condition of wood poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The life expectancy of wood poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

5.2 Health Index Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DF$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF_n} \times \mathrm{WCPF_n})}{\sum_{n=1} \beta_n (\mathrm{CPF_{n.max}} \times \mathrm{WCPF_n})} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter
DF --- De-rating Factor

CPF --- Sub-Condition Parameter Factor
WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

5.3 Condition and Sub-Condition Parameters

Those Poles that are **Red Cedar Butt Treated** have been **de-rated** to 80% of their calculated Health Index Value.

Table 5-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Pole physical	3	4
2	Pole accessories	1	4
3	Overall	4	4

Table 5-2 Pole Physical (m=2) Weights and Maximum CPF

n	Sub-condition parameter	$WCPF_n$	$CPF_{n.max}$
1	Animal Damage	2	4
2	Lean	1	4
3	Rot / Soft	2	4
4	Crack	2	4
5	Hole / Void	2	4
6	Hollow	2	4
7	Chunk	2	4
8	Damp / Wet	2	4
9	Bend / Hit / Damage	2	4
10	Poor Top	2	4

Table 5-3 Pole Accessory (m=3) Weights and Maximum CPF

N	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
2	Guy Wire	OK = 4; All others = 0	3	4
3	Defective Ground	OK=4; Exposed/connection issue/rod above grade= 2; Damaged = 0	2	4
4	Crossarm	OK=4; Crooked/Loose = 2; Damaged = 0	1	4
5	Riser (Cable Guard)	OK=4; Exposed/Loose = 2; Damaged = 0	1	4

Table 5-4 Overall (m=4) Weights and Maximum CPF

N	Sub-condition parameter	$WCPF_n$	$CPF_{n.max}$
1	Overall	3	4
3	Age	2	4

5.3.1 *Age*

Table 5-5 Pole Age

Condition Rating	CPF	Condition Description
A	4	0
B	3	10
C	2	25
D	1	40
E	0	>50

5.4 Health Index Results

The total population of assets for this category is 22,247. The Sample Size or total number of assets within the population that have data is 5985. However those pole recently inspected were of newer vintage. Age was provided for 13,135 units (encompassing the 4943 units of the 5985 sample) so a comparison of the age range of the sample, as compared to the 13,135 population was done.

The Health Indexing Result by Unit and Percentage and the age range comparison of the sample to a broader sample of the pole population are presented below:

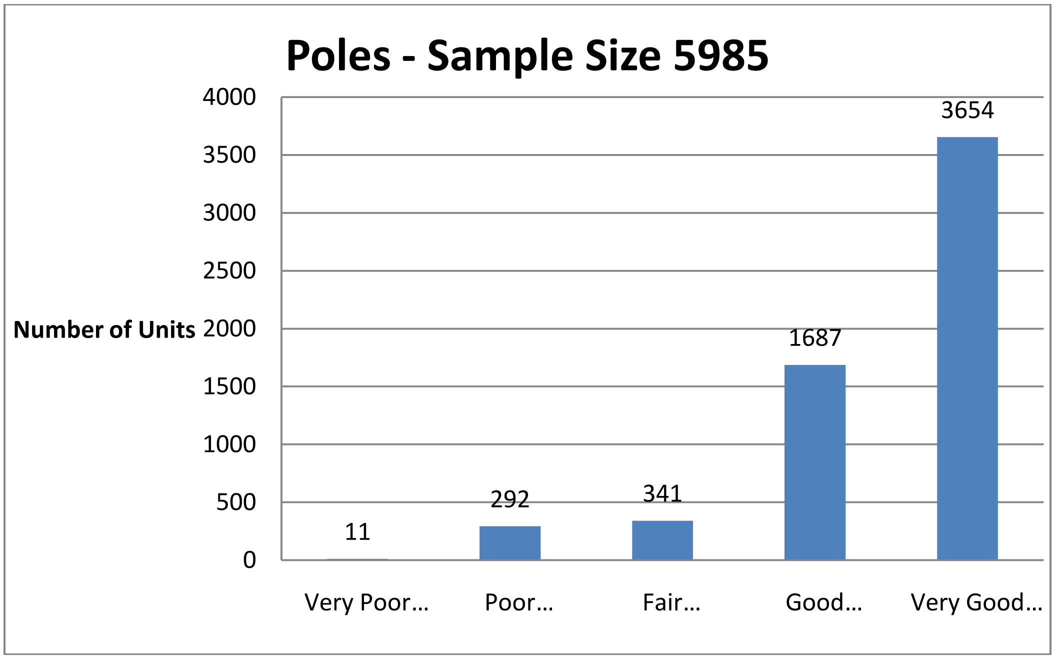

Figure 5-1 Health Index Distribution by Unit

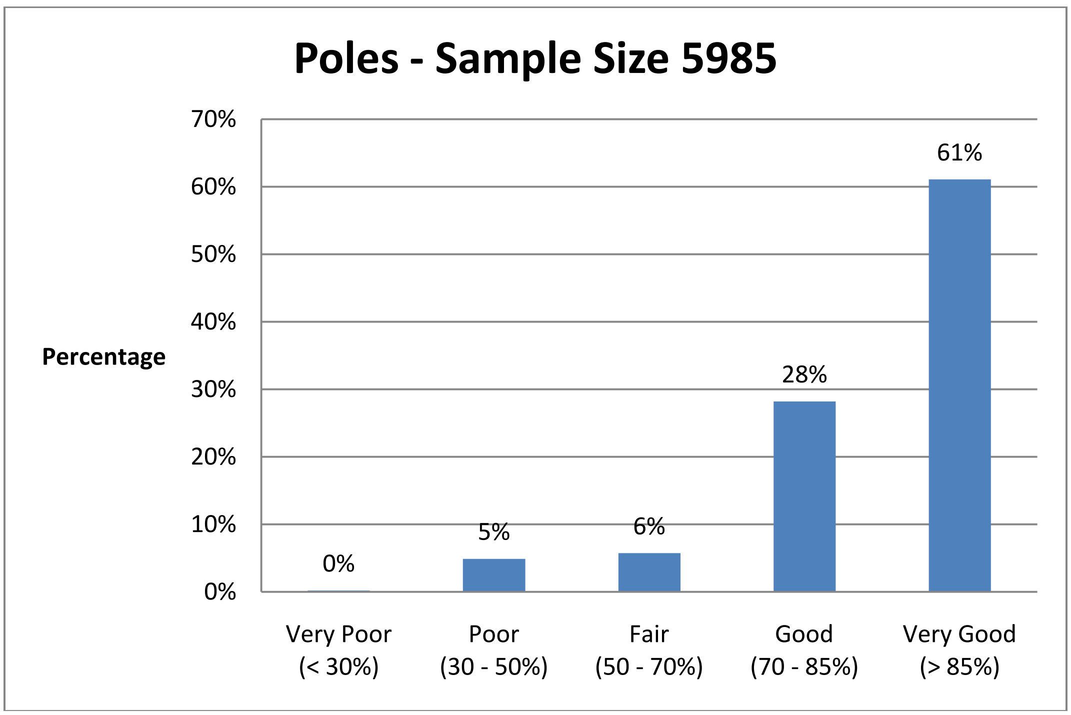

Figure 5-2 Health Index Distribution by Percentage

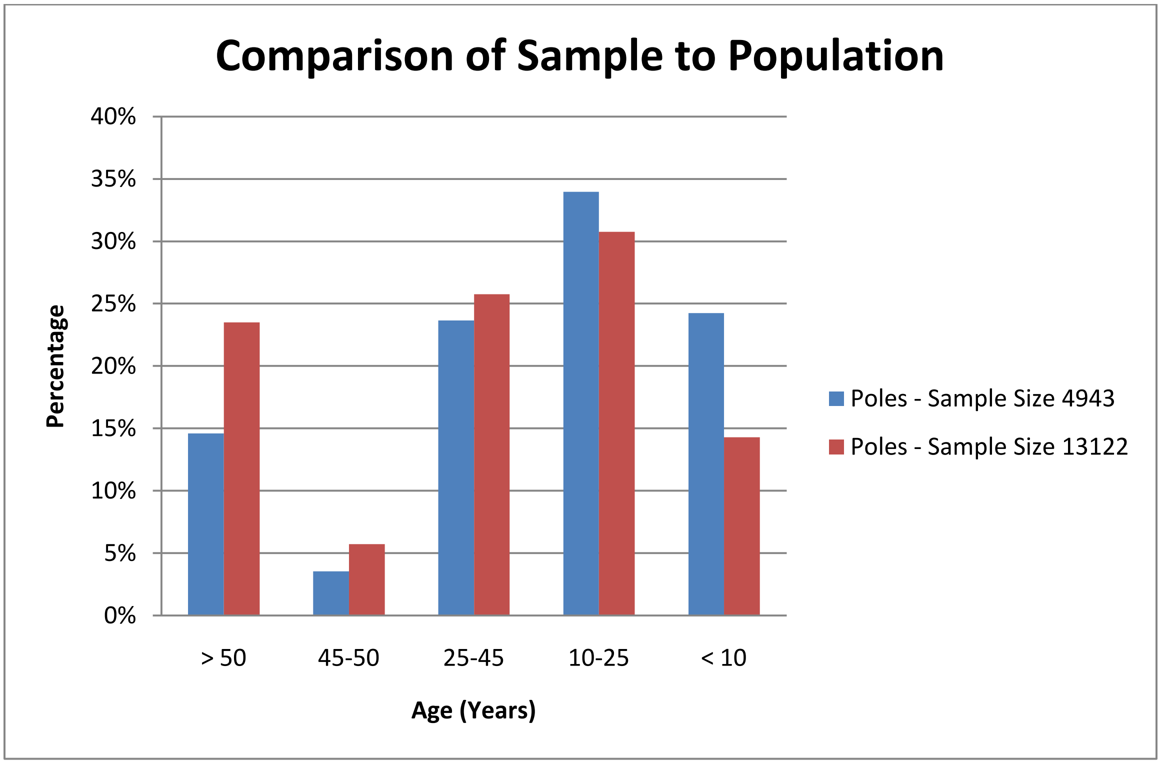

Figure 5-3 Comparison of Sample Age Data to a Larger Sample of the Population Age Data

5.5 Field Inspection Results

Four Poles were inspected. The data can be found in Section E FIELD INSPECTION FORMS and are summarized in Figure 5-4 below. The units were in good and fair condition.

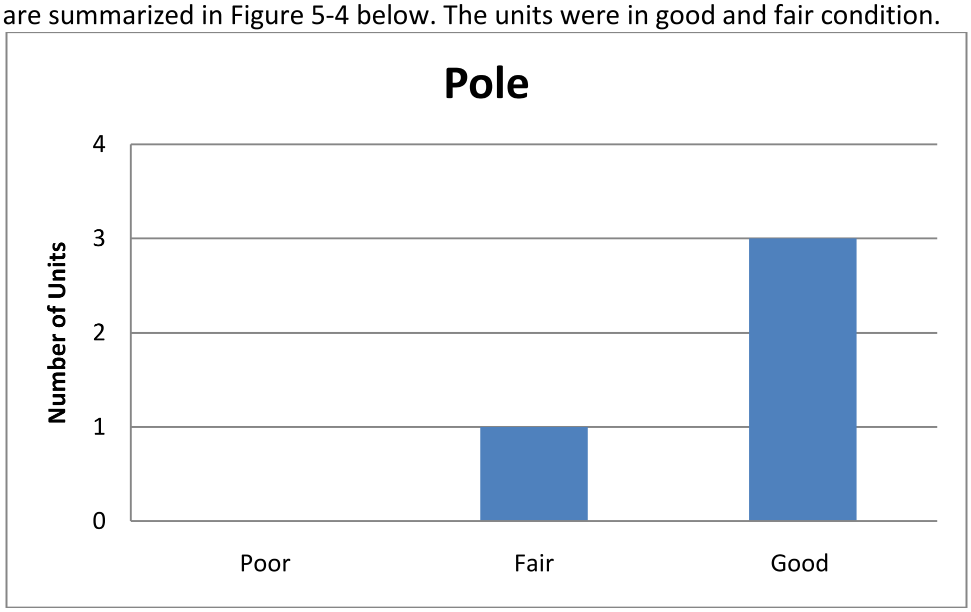

Figure 5-4 Field Inspection Results

5.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 40 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%.

5.6.1 *Optimal Capital Replacement Plan*

Figure 5-5 shows the number of Poles that will need to be replaced over the next 20 years extrapolated for the whole population from the sample (27% of the population) with adequate condition data. However, it could be seen from Figure 5-3 that the overall condition of the poles in the sample is better than that for the population with only age available due to the investments made in testing and replacing poles found to be in poor condition. Therefore, to achieve similar Health Index distribution for the whole population more capital expenditures than what is shown would be required.

A separate analysis which is beyond the scope of this project would be required to estimate the incremental capital amount needed to improve overall condition of the whole pole population to the level of the poles in the sample with adequate condition data.

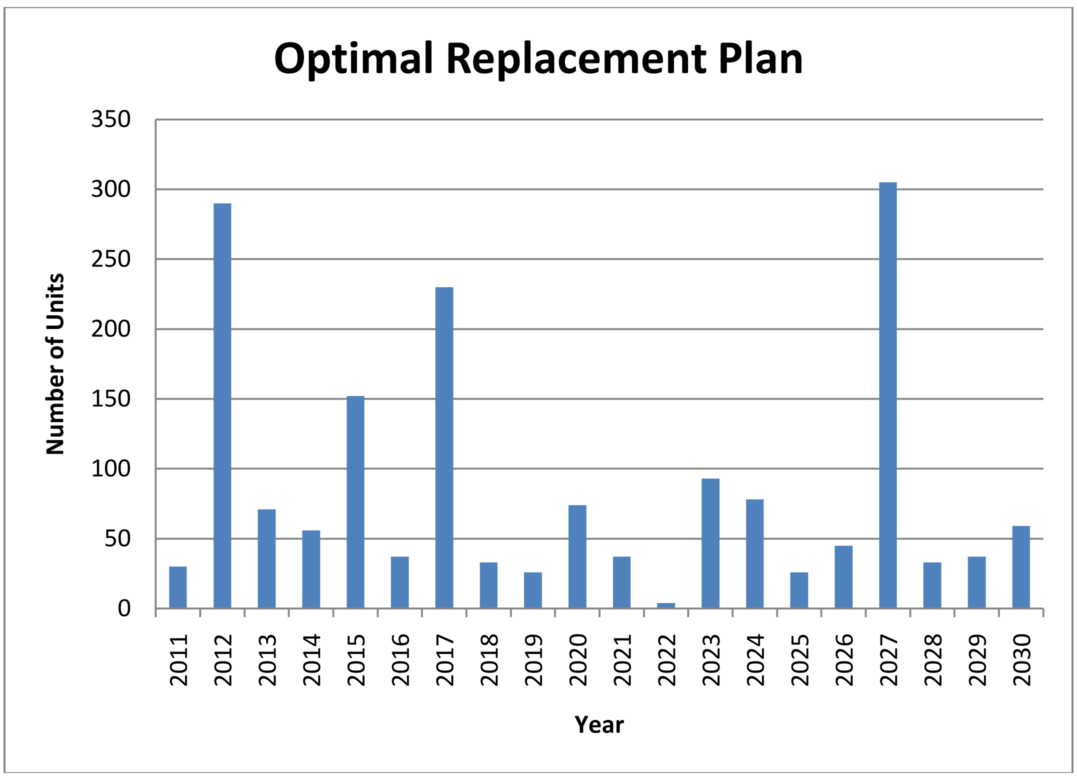

Figure 5-5 Optimal Replacement Plan

5.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 30 units next year. While this is optimal based on NPEI's Pole HI scores, it may not be ideal financially.

Poles are typically replaced **reactively** (end of life.) Since the HI scores indicate the majority of failures happening in spikes over the next 30 years, NPEI can take a Levelized approach by replacing assets before they are estimated to fail.

Figure 5-6 shows a Levelized capital replacement plan, where replacements pole can occur over a longer period of time.

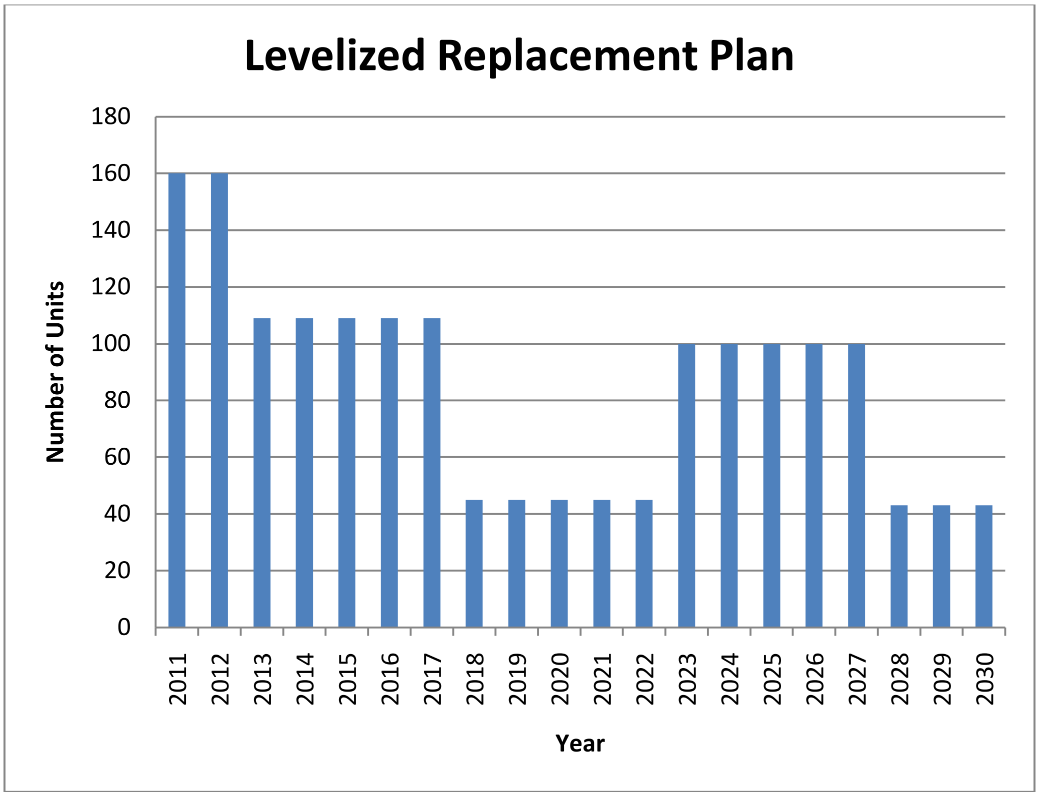

Figure 5-6 Levelized Replacement Plan

5.7 Data Gap Closure

The only data gap for poles in this project is the measured pole strength. It represents the actual physical size changes due to pole degradation. It is useful in scheduling reinforcement or replacement.

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6 Pad Mounted Switchgear

This asset class consists of pad mounted switchgear. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements.

6.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Non-functioning padlocks
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions where the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

6.2 Formulation

Recommended Health Index Formulations:

$$HI = \frac{\sum_{m=1} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

CPS --- Condition Parameter Score
WCP --- Weight of Condition Parameter

CPF --- Sub-Condition Parameter Factor

WCPF --- Weight of Condition Parameter Factor

α_m --- Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n --- Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)

6.3 Condition and Sub-Condition Parameters

Switchgear that is **Air Insulated** and near a **major roadway** is **de-rated** to **30%** of the calculated Health Index Value.

Table 6-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Physical Condition	3	4
2	Switch Condition	5	4
3	Insulation	7	4
4	Service record	5	4
5	Testing	10	4

Table 6-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Enclosure	3	4
2	Access (ok/not ok)	1	4
3	Base (ok/not ok)	2	4

Table 6-3 Switch/Fuse Condition (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Grounding	1	4

Table 6-4 Insulation (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Insulator (ok/not ok)	1	4

Table 6-5 Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	Inspection result (Pass/Fail)	1	4

Table 6-6 Tests (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	$CPF_{n.max}$
1	IR Scan (Pass/Fail)	1	4
2	Ultrasonic (Pass/Fail)	1	4

6.4 Health Index Results

The total population of assets for this category is 89. The Sample Size or total number of assets within the population that have data is 38.

The Health Indexing Result by Unit and Percentage are presented below:

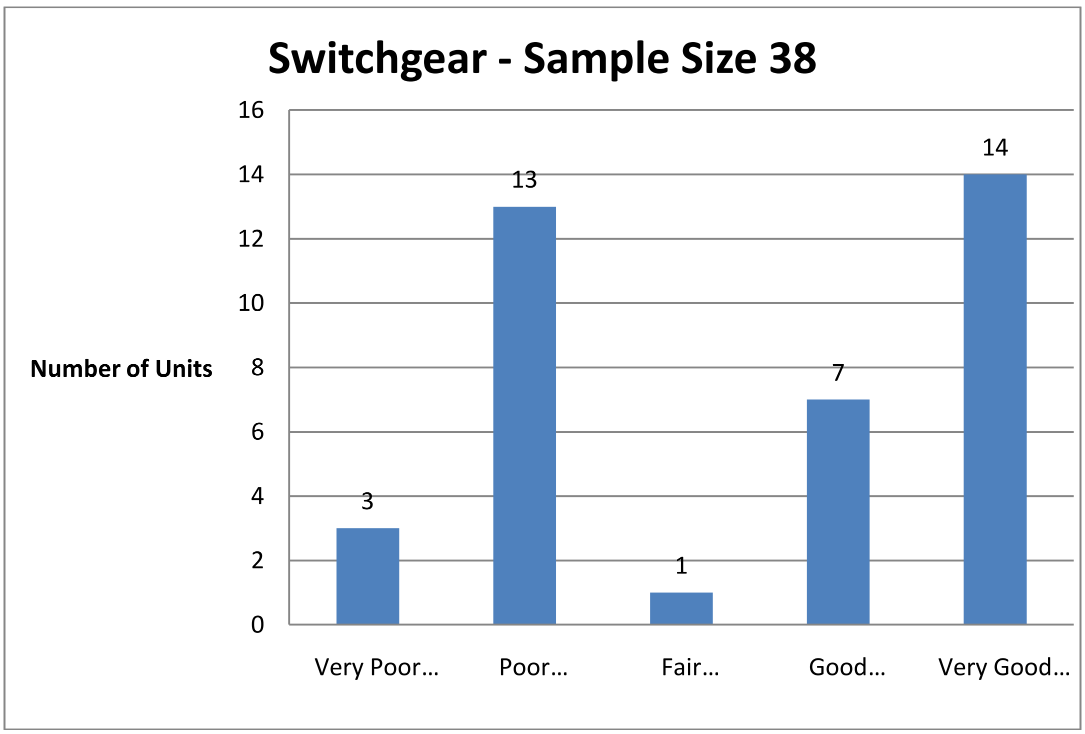

Figure 6-1 Health Index Distribution by Unit

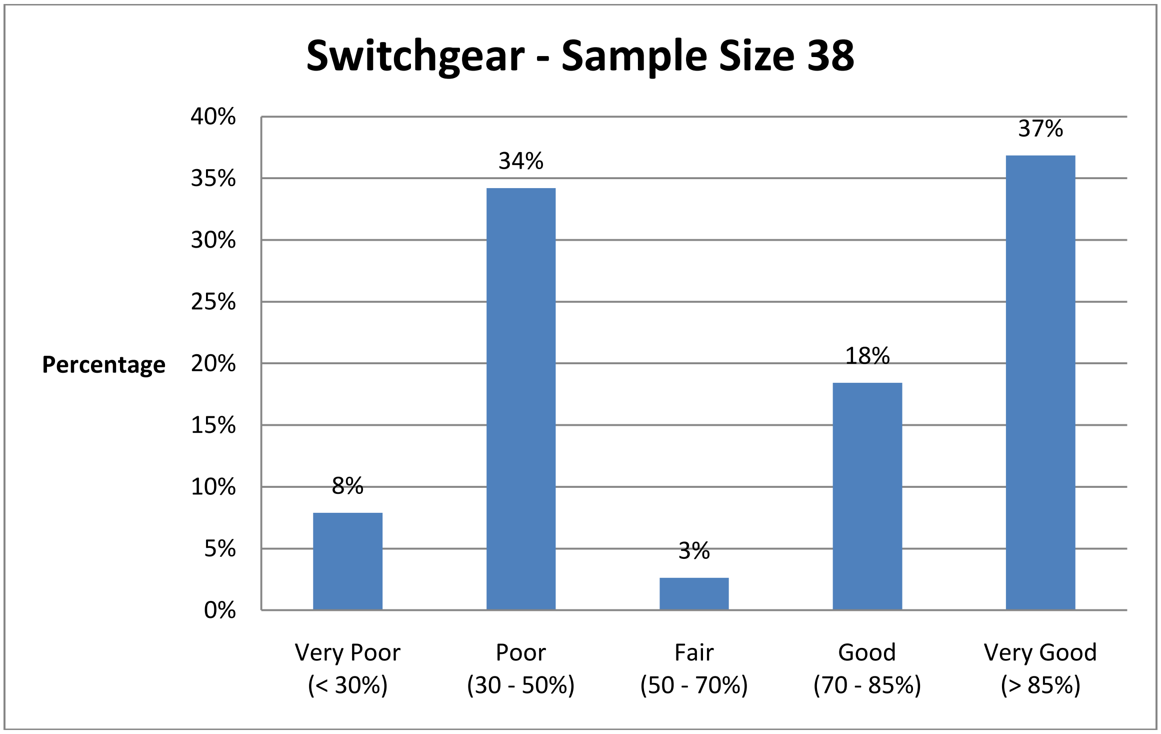

Figure 6-2 Health Index Distribution by Percentage

6.5 Field Inspection Results

On Pad Mounted Switchgear was inspected. The data can be found in Section E FIELD INSPECTION FORMS and are summarized in Figure 6-3 below.

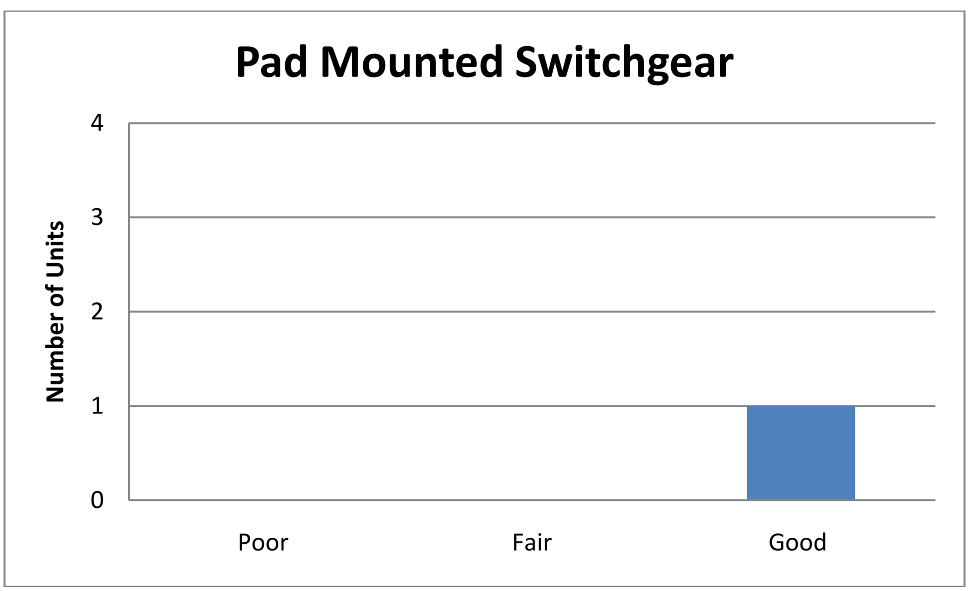

Figure 6-3 Field Inspection Results

6.6 Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 20 years the probability of failure is 10% and at age of 45 years the probability of failure is 90%.

6.6.1 *Optimal Capital Replacement Plan*

Figure 6-4 shows the number of Pad Mounted Switchgear units that will need to be replaced over the next 20 years extrapolated from the sample with adequate condition data (43%). There is no basis to confirm or deny whether this assumption is reasonable, so it is recommended to accelerate a process of collecting condition data for the reminder of the population.

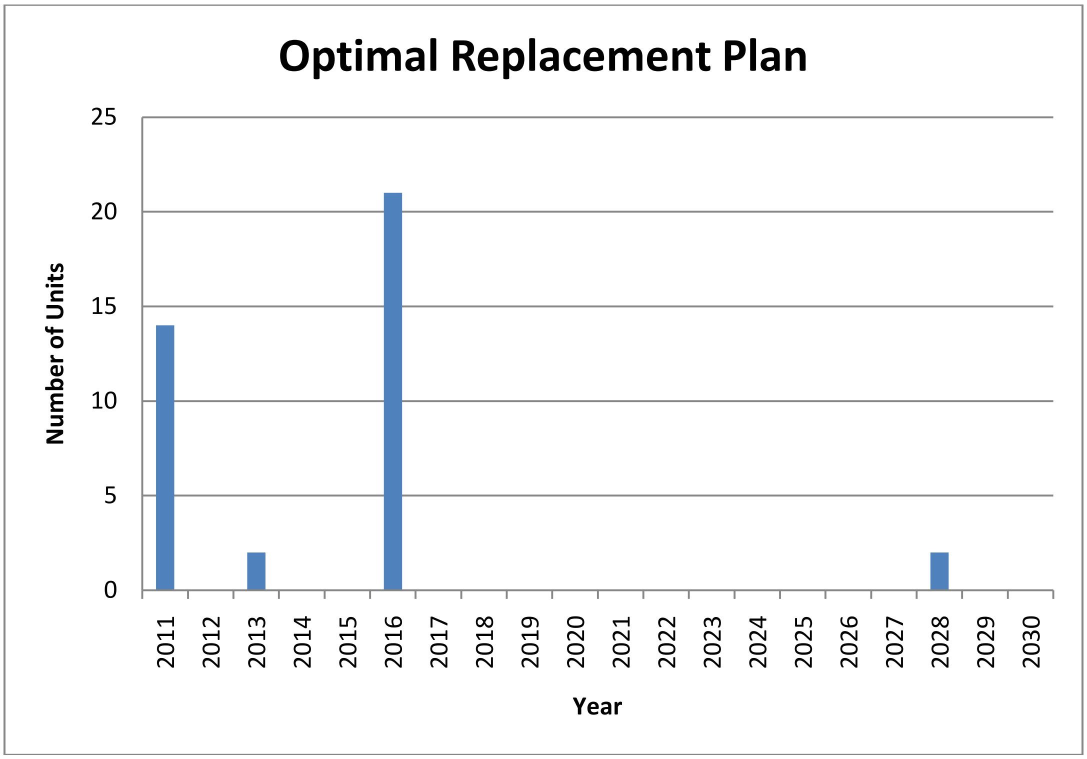

Figure 6-4 Optimal Replacement Plan

6.6.2 *Levelized Capital Replacement Plan*

For this asset category, the optimal replacement plan suggests replacing 14 units next year. While this is optimal based on NPEI's Pad Mounted Switchgear HI scores, it may not be ideal financially.

Standard Pad Transformers are typically replaced reactively (end of life.) However NPEI is replacing those transformers that are air insulated and near a major roadway **proactively**. The Levelized replacement plan allows for Switchgear that would optimally be replaced in one year to be replaced over a period of 5 years.

Figure 6-5 shows a Levelized capital replacement plan, where switchgear replacements can occur over a longer period of time.

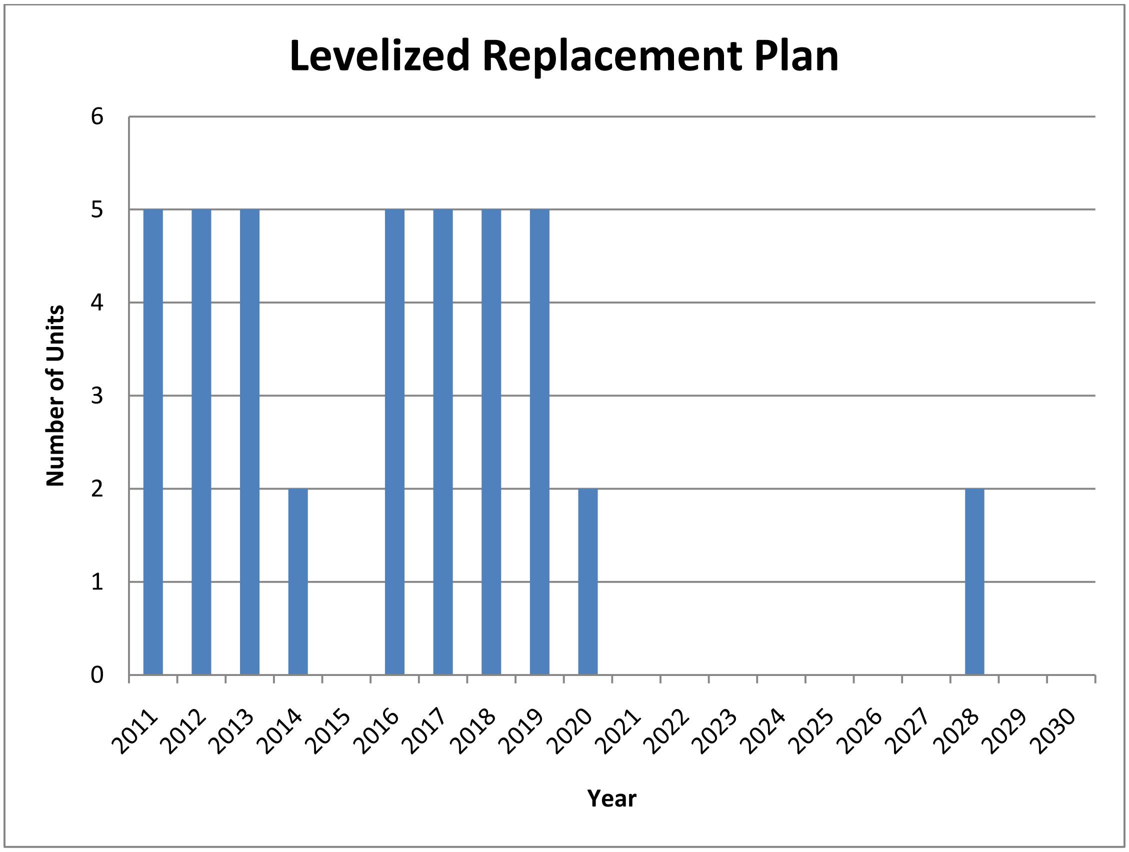

Figure 6-5 Levelized Replacement Plan

6.7 Data Gap Closure

The following table summarizes the data gap for pad mounted switchgear in this project.

Sub-system	Condition Parameter	Data Collection Priority
Physical condition	Debris/dirty	☆
Switch/fuse condition	Switch condition	☆ ☆ ☆
	Arc chute	☆ ☆
Insulation	Barriers	☆ ☆
Service record	Age	☆

Switch main contact and its arc suppression parts are the main device inside pad mounted switchgear.

D CONCLUSIONS AND RECOMMENDATIONS

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Conclusions and Recommendations

1. There was generally sufficient condition data available for Power Transformers, Large Pad-mounted Transformers, Poles (inspected after 2008) and Switchgear.

2. For Pole-mounted transformers, only age is available and operating practices (i.e., customers). Gathering and recording detailed inspection data should be considered.

3. For Standard Pad Mounted transformers, age was provided for 87% of the population however sufficient data was provided for only 28% of the population. It is recommended that NPEI collect data for a greater population of Pad Mounted Transformers.

4. For Poles that have not been inspected, age is only available for half of the population. Sufficient age and inspection data should be collected for the rest of the population.

5. Sufficient data was not available for Underground Cables. It is recommended that inspection and maintenance information be collected for these assets to enable future asset condition assessment.

6. A separate study is required to determine appropriate increase in the pole replacement program over the levels extrapolated from the sample with adequate condition data to achieve the desired overall Health Index distribution (similar to that of the sample).

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E FIELD INSPECTION FORMS

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Asset Condition Survey
Transformer Stations

Substation	Kalar TS	101
Op Desn	25 MVA	102
Age	Built 2004	103
HV / LV	115kV / 13.8kV	104
Location	Kalar Rd	105

1.0 Power Transformer Age — 107

1.1 Inspections — Circle ONLY one

1.1 Bushing Condition	A B C D N U	109
1.2 Oil Leaks	A B C D N U	110
1.3 Main Tank/Cabinets Condition	A B C D N U	111
1.4 Radiators and Conservator Condition	A B C D N U	112
1.5 Gaskets and Seals Condition	A B C D N U	113
1.6 Pumps and Fans Condition	A B C D N U	114
1.7 Primary Connectors/Conductors Condition	A B C D N U	115
1.8 Secondary Connections/Control Condition	A B C D N U	116
1.9 Foundation/Support Steel/Grounding Condition	A B C D N U	117
1.10 Fire Protection/Spill Containment	A B C D N U	118
1.12 Overall Power Transformer Condition	A B C D N U	119

Tapchangers (if applicable) (On-Load Tap Changers)

1.13 Tank Condition	A B C D N U	122
1.14 Tank Leaks	A B C D N U	123
1.15 Gaskets/Seals/Pressure Relief Condition	A B C D N U	124
1.16 LTC Control and Mechanism Cabinet Condition	A B C D N U	125
1.17 Control and Mechanism Cabinet Components	A B C D N U	126
1.18 Overall Tap Changer Condition	A B C D N U	127

2 Breakers Voltage — 129; Age — 130

2.1 Bushing Condition	A B C D N U	131
2.2 Tank Condition	A B C D N U	132
2.3 Oil Leaks	A B C D N U	133
2.4 Controls and Mechanism	A B C D N U	134
2.5 Overall Breaker Condition	A B C D N U	135

3 Metal Clad Switch Gear Assemblies Voltage — 137; Age — 138

3.1 Structure Integrity (paint, corrosion, water leaks)	A B C D N U	139
3.2 General Condition (evidence of maintenance)	A B C D N U	140
3.3 Overall Switchgear Assembly Condition	A B C D N U	141

4 Buildings Age — 143

4.1 Condition of structure (roof, walls)	A B C D N U	144
4.2 Condition of doors and locks	A B C D N U	145
4.3 Condition of Lightning	A B C D N U	146
4.4 Overall Building Condition	A B C D N U	147

Data sources used

Mtce inspection record [ ] Interviews [ ] Photos taken (no.) [ ] 150

Inspector Name and Date — Name: G. Ebersbags — Date: Nov 18, 2010 — 152

(write any comments or concerns on the back of this form)

6/8/2006 Survey Form-1/1 Transformer Stations VI Form.xls

Asset Condition Survey
Transformer Stations

Substation	Station 17	100
Op Desn	5000 kVA	102
Age	1974 (1999 Tx)	103
HV / LV	13.8KV	104
Virginia Rd Location	Station 17	105

Item		Rating	
1.0 Power Transformer	Age		107
1.1 Inspections		Circle ONLY one	
1.1 Bushing Condition		A B C D N U	109
1.2 Oil Leaks		A B C D N U	110
1.3 Main Tank/Cabinets Condition		A B C D N U	111
1.4 Radiators and Conservator Condition		A B C D N U	112
1.5 Gaskets and Seals Condition		A B C D N U	113
1.6 Pumps and Fans Condition		A B C D N U	114
1.7 Primary Connectors/Conductors Condition		A B C D N U	115
1.8 Secondary Connections/Control Condition		A B C D N U	116
1.9 Foundation/Support Steel/Grounding Condition		A B C D N U	117
1.10 Fire Protection/Spill Containment		A B C D N U	118
1.12 Overall Power Transformer Condition		A B C D N U	119
Tapchangers (if applicable)			
1.13 Tank Condition		A B C D N U	122
1.14 Tank Leaks		A B C D N U	123
1.15 Gaskets/Seals/Pressure Relief Condition		A B C D N U	124
1.16 LTC Control and Mechanism Cabinet Condition		A B C D N U	125
1.17 Control and Mechanism Cabinet Components		A B C D N U	126
1.18 Overall Tap Changer Condition		A B C D N U	127
2 Breakers	Voltage		129
	Age		130
2.1 Bushing Condition		A B C D N U	131
2.2 Tank Condition		A B C D N U	132
2.3 Oil Leaks		A B C D N U	133
2.4 Controls and Mechanism		A B C D N U	134
2.5 Overall Breaker Condition		A B C D N U	135
3 Metal Clad Switch Gear Assemblies	Voltage		137
	Age		138
3.1 Structure Integrity (paint, corrosion, water leaks)		A B C D N U	139
3.2 General Condition (evidence of maintenance)		A B C D N U	140
3.3 Overall Switchgear Assembly Condition		A B C D N U	141
4 Buildings (Newer)	Age		143
4.1 Condition of structure (roof, walls)		A B C D N U	144
4.2 Condition of doors and locks		A B C D N U	145
4.3 Condition of Lightning		A B C D N U	146
4.4 Overall Building Condition		A B C D N U	147

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 150

Inspector Name and Date — Name: [illegible] Date: Nov 18, 2010 152

(write any comments or concerns on the back of this form)

Asset Condition Survey
Transformer Stations

Substation	Pelham Station	101
Op Desn		102
Age	6mos Refurbish	103
HV / LV	27.6KV 4,160KV	104
Location	Fonthill	105

1.0 Power Transformer — Age: ______ 107

1.1 Inspections — Circle ONLY one

Item	Rating	Code
1.1 Bushing Condition	A B C D N U	108
1.2 Oil Leaks	A B C D N U	110
1.3 Main Tank/Cabinets Condition	A B C D N U	111
1.4 Radiators and Conservator Condition	A B C D N U	113
1.5 Gaskets and Seals Condition	A B C D N U	112
1.6 Pumps and Fans Condition	A B C D N U	114
1.7 Primary Connectors/Conductors Condition	A B C D N U	115
1.8 Secondary Connections/Control Condition	A B C D N U	116
1.9 Foundation/Support Steel/Grounding Condition	A B C D N U	117
1.10 Fire Protection/Spill Containment	A B C D N U	118
1.12 Overall Power Transformer Condition	A B C D N U	119

Tapchangers (If applicable)

Item	Rating	Code
1.13 Tank Condition	A B C D N U	122
1.14 Tank Leaks	A B C D N U	123
1.15 Gaskets/Seals/Pressure Relief Condition	A B C D N U	124
1.16 LTC Control and Mechanism Cabinet Condition	A B C D N U	125
1.17 Control and Mechanism Cabinet Components	A B C D N U	126
1.18 Overall Tap Changer Condition	A B C D N U	127

2 Breakers — Voltage: ______ 129 — Age: ______ 130

Item	Rating	Code
2.1 Bushing Condition	A B C D N U	131
2.2 Tank Condition	A B C D N U	132
2.3 Oil Leaks	A B C D N U	133
2.4 Controls and Mechanism	A B C D N U	134
2.5 Overall Breaker Condition	A B C D N U	135

3 Metal Clad Switch Gear Assemblies — Voltage: ______ 137 — Age: ______ 138

Item	Rating	Code
3.1 Structure Integrity (paint, corrosion, water leaks)	A B C D N U	139
3.2 General Condition (evidence of maintenance)	A B C D N U	140
3.3 Overall Switchgear Assembly Condition	A B C D N U	141

4 Buildings — Age: ______ 143

Item	Rating	Code
4.1 Condition of structure (roof, walls)	A B C D N U	144
4.2 Condition of doors and locks	A B C D N U	145
4.3 Condition of Lightning	A B C D N U	146
4.4 Overall Building Condition	A B C D N U	147

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) ______ 158

Inspector Name and Date — Name: G. Bombagen — Date: Nov 18, 2010

(write any comments or concerns on the back of this form)

Asset Condition Survey
Transformer Stations

Substation	Station 10	101
Op Desg	5 AVA	102
Age	April 1996	103
HV / LV	13.8 KV / 416a 240	104
Location		105

1.0 Power Transformer — Age — 107

1.1 Inspections — Circle ONLY one

1.1 Bushing Condition	A B C D N U	109
1.2 Oil Leaks	A B C D N U	110
1.3 Main Tank/Cabinets Condition	A B C D N U	111
1.4 Radiators and Conservator Condition	A B C D N U	112
1.5 Gaskets and Seals Condition	A B C D N U	113
1.6 Pumps and Fans Condition	A B C D N U	114
1.7 Primary Connectors/Conductors Condition	A B C D N U	115
1.8 Secondary Connections/Control Condition	A B C D N U	116
1.9 Foundation/Support Steel/Grounding Condition	A B C D N U	117
1.10 Fire Protection/Spill Containment	A B C D N U	118
1.12 Overall Power Transformer Condition	A B C D N U	119

Tapchangers (if applicable) Off-Load.

1.13 Tank Condition	A B C D N U	122
1.14 Tank Leaks	A B C D N U	123
1.15 Gaskets/Seals/Pressure Relief Condition	A B C D N U	124
1.16 LTC Control and Mechanism Cabinet Condition	A B C D N U	125
1.17 Control and Mechanism Cabinet Components	A B C D N U	126
1.18 Overall Tap Changer Condition	A B C D N U	127

2 Breakers Hyde Park SF6 Outside — Voltage — 129; Age — 130

2.1 Bushing Condition	A B C D N U	131
2.2 Tank Condition	A B C D N U	132
2.3 Oil Leaks	A B C D N U	133
2.4 Controls and Mechanism	A B C D N U	134
2.5 Overall Breaker Condition	A B C D N U	135

3 Metal Clad Switch Gear Assemblies — Voltage — 137; Age 1960's — 138

3.1 Structure Integrity (paint, corrosion, water leaks)	A B C D N U	139
3.2 General Condition (evidence of maintenance)	A B C D N U	140
3.3 Overall Switchgear Assembly Condition	A B C D N U	141

4 Buildings — Age — 143

4.1 Condition of structure (roof, walls)	A B C D N U	144
4.2 Condition of doors and locks	A B C D N U	145
4.3 Condition of Lightning	A B C D N U	146
4.4 Overall Building Condition	A B C D N U	147

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 150

Inspector Name and Date — Name: G. Ebersbayer — Date: Nov. 16, 2010 — 151

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation	
Op Desn	
Age	10 Yrs
Voltage	13.8kv
Location	Kalar TS / Jacob Bldg

1.0 Pad Mounted Switchgear

	Circle ONLY one
1.1 Main Cabinet Condition	A B C D N U
1.2 Pad Condition	A B C D N U
1.3 Insulators Condition	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Electrical Connections Condition	A B C D N U
1.7 Signs of Over Heating?	A B C D N U
1.7 Overall Condition	A B C D N U

Cables and Terminations

1.8 Cable Condition	A B C D N U
1.9 Termination Condition	A B C D N U
1.1 Neutral Condition	A B C D N U
1.11 Overall Cable Condition	A B C D N U

2 Pad Mounted Transformer Location #800561 150kVA

2.1 Main Cabinet Condition	A B C D N U
2.2 Pad Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Operating Temperature	A B C D N U
2.5 Overall Transformer Condition	A B C D N U

Cables and Terminations

2..5 Cable Condition	A B C D N U
2.6 Termination Condition	A B C D N U
2.7 Neutral Condition	A B C D N U
2.8 Overall Cable Condition	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) ☐

Inspector Name and Date — Name: G Ebersberger — Date: Nov. 18, 2010

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation	
Op Desn	
Age	
Voltage	16 KV · 1Ø 75KVA
Location	Various - Manola St W. of Victoria Ave (off Hwy 8)

1.0 Pad Mounted Switchgear

	Circle ONLY one
1.1 Main Cabinet Condition	A B C D N U
1.2 Pad Condition	A B C D N U
1.3 Insulators Condition	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Electrical Connections Condition	A B C D N U
1.7 Signs of Over Heating?	A B C D N U
1.7 Overall Condition	A B C D N U

Cables and Terminations

1.8 Cable Condition	A B C D N U
1.9 Termination Condition	A B C D N U
1.1 Neutral Condition	A B C D N U
1.11 Overall Cable Condition	A B C D N U

2 Pad Mounted Transformer — Location

(Minor) Heat Damage to tanks Throughout Subd.

2.1 Main Cabinet Condition	A B C D N U
2.2 Pad Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Operating Temperature	A B C D N U
2.5 Overall Transformer Condition	A B C D N U

Cables and Terminations

2..5 Cable Condition	A B C D N U
2.6 Termination Condition	A B C D N U
2.7 Neutral Condition	A B C D N U
2.8 Overall Cable Condition	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.)

Inspector Name and Date — Name — Date

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation		101
Op Desn		102
Age	12-1965.	103
Voltage	8.2kV / 120 240V. 10	
Location	Belin Station.	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	108
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condtion	A B C D N U	116

Cables and Terminations

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.? Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer — Location: | 125

On Submersible Tx Pad, 1940s.

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) ☐ 141

Inspector Name and Date — Name: G Ebersberger — Date: Nov. 18, 2010 144

(write any comments or concerns on the back of this form)

Asset Condition Survey
Overhead Distribution

Substation	
Op Desn	
Age	Unknown
Voltage	
Location	Kalar TS

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one
1.1 Insulator Condition	A B C D N U
1.2 Mechanical Support Condition	A B C D N U
1.3 Signs of Over Heating?	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Motor Operator and Control Condition	A B C D N U
1.7 Overall Condtion	A B C D N U

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U
1.2 Mechanical Support Condition	A B C D N U
1.3 Signs of Over Heating?	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Overall Condtion	A B C D N U

3 Pole Location

1.1 Holes and Cracks ?	A B C D N U
1.2 Rot ?	A B C D N U
1.3 Cross arm Condition	A B C D N U
1.4 Overall Pole Condtion	A B C D N U

3 Pole Mounted Transformer Location

1.1 Tank Integrity	A B C D N U
1.2 Oil Leak	A B C D N U
1.3 Bushing Condition	A B C D N U
1.4 Electrical Connections	A B C D N U
1.5 Signs of Overheating?	A B C D N U
1.6 Overall Transformer Condition	

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.) ☐

	Name	Date
Inspector Name and Date	G. [illegible]	Nov 15, 2010

(write any comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation		101
Op Desc	XLPE / PILC	102
Age		103
Voltage	13.8KV	104
Location	Various	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	109
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condition	A B C D N U	116

Cables and Terminations

(Sulphurous Soil).
Black Corrosion.
350 MCM, 600 MCM.

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer Location 125

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 141

Inspector Name and Date — Name: G. Ebersberger — Date: Nov 18, 2010 144
(write any comments or concerns on the back of this form)

Asset Condition Survey
Overhead Distribution

Substation		101
Op Dsgn		102
Age	A 16 Kv	103
Voltage		104
Location	Pelham Corners	105

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one	
1.1 Insulator Condition	A B C D N U	109
1.2 Mechanical Support Condition	A B C D N U	110
1.3 Signs of Over Heating?	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Motor Operator and Control Condition	A B C D N U	114
1.7 Overall Condtion	A B C D N U	115

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U	120
1.2 Mechanical Support Condition	A B C D N U	121
1.3 Signs of Over Heating?	A B C D N U	122
1.4 Contact Condition	A B C D N U	123
1.5 Operating Mechanism Condition	A B C D N U	124
1.6 Overall Condtion	A B C D N U	125

3 Pole

Location

1.1 Holes and Cracks ?	A B C D N U	130
1.2 Rot ?	A B C D N U	121
1.3 Cross arm Condition	A B C D N U	122
1.4 Overall Pole Condtion	A B C D N U	123

3 Pole Mounted Transformer

Location: Pelham #5

1.1 Tank Integrity	A B C D N U	130
1.2 Oil Leak	A B C D N U	131
1.3 Bushing Condition	A B C D N U	132
1.4 Electrical Connections	A B C D N U	133
1.5 Signs of Overheating?	A B C D N U	135
1.6 Overall Transformer Condition		

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 140

	Name	Date	
Inspector Name and Date	[illegible]	Nov 18, 200[illegible]	142

(write any comments or concerns on the back of this form)

Asset Condition Survey
Overhead Distribution

Substation 101
Op Dept 102
Age 103
Voltage 104
Location McLeod Rd. Overpass 105

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one	
1.1 Insulator Condition	A B C D N U	109
1.2 Mechanical Support Condition	A B C D N U	110
1.3 Signs of Over Heating?	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Motor Operator and Control Condition	A B C D N U	114
1.7 Overall Condition	A B C D N U	115

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U	120
1.2 Mechanical Support Condition	A B C D N U	121
1.3 Signs of Over Heating?	A B C D N U	122
1.4 Contact Condition	A B C D N U	123
1.5 Operating Mechanism Condition	A B C D N U	124
1.6 Overall Condition	A B C D N U	125

3 Pole

Location

1.1 Holes and Cracks ?	A B C D N U	120
1.2 Rot ?	A B C D N U	121
1.3 Cross arm Condition	A B C D N U	122
1.4 Overall Pole Condtion	A B C D N U	125

3 Pole Mounted Transformer

Location

1.1 Tank Integrity	A B C D N U	130
1.2 Oil Leak	A B C D N U	131
1.3 Bushing Condition	A B C D N U	132
1.4 Electrical Connections	A B C D N U	133
1.5 Signs of Overheating?	A B C D N U	135
1.6 Overall Transformer Condition		

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 140

Inspector Name and Date

Name [illegible]

Date Nov 18, 2010 142

... comments or concerns on the back of this form)

Asset Condition Survey
Underground Distribution

Substation		101
Op Dsgn	SF6 G&W	102
Age		103
Voltage		104
Location	Niagara Square Mall	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	109
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condtion	A B C D N U	116

Cables and Terminations

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer

Location 125

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.) 141

Inspector Name and Date — Name: G.E Dorsbergen — Date: Nov. 18, 2010 144

(write any comments or concerns on the back of this form)

6/9/2008 Survey Form-1/1 Underground Distribution VI Form.xls

Asset Condition Survey
Underground Distribution

Substation		101
Op Desn		102
Age		103
Voltage		104
Location	Niagara Square	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	109
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condition	A B C D N U	116

Cables and Terminations

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer Location: 500 KVA #800123 125

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) 141

	Name	Date	
Inspector Name and Date	G. Eber...	Nov 18, 2010	144

(write any comments or concerns on the back of this form)

6/9/2006 Survey Form-1/1 Underground Distribution VI Form.xls

Asset Condition Survey
Underground Distribution

Substation		101
Op Desc		102
Age		103
Voltage		104
Location	Pelham Corners	105

1.0 Pad Mounted Switchgear

	Circle ONLY one	
1.1 Main Cabinet Condition	A B C D N U	109
1.2 Pad Condition	A B C D N U	110
1.3 Insulators Condition	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Electrical Connections Condition	A B C D N U	114
1.7 Signs of Over Heating?	A B C D N U	115
1.7 Overall Condtion	A B C D N U	116

Cables and Terminations

1.8 Cable Condition	A B C D N U	120
1.9 Termination Condition	A B C D N U	121
1.1 Neutral Condition	A B C D N U	122
1.11 Overall Cable Condition	A B C D N U	123

2 Pad Mounted Transformer Location 125

2.1 Main Cabinet Condition	A B C D N U	127
2.2 Pad Condition	A B C D N U	128
2.3 Oil Leaks	A B C D N U	129
2.4 Operating Temperature	A B C D N U	130
2.5 Overall Transformer Condition	A B C D N U	131

Cables and Terminations

2..5 Cable Condition	A B C D N U	135
2.6 Termination Condition	A B C D N U	136
2.7 Neutral Condition	A B C D N U	137
2.8 Overall Cable Condition	A B C D N U	138

Data sources used

Mtce inspection record [ ] Interviews [ ] Photos taken (no.) 145

Inspector Name and Date — Name: G. Ebershager — Date: Nov. 18, 2010 146
(write any comments or concerns on the back of this form)

5/9/2005 Survey Form-1/1 Underground Distribution V1 Form.xls

Asset Condition Survey
Underground Distribution

Substation	Stn 28
Op Desn	
Age	
Voltage	13.8KV
Location	Lundy's Lane at Montrose

1.0 Pad Mounted Switchgear

	Circle ONLY one
1.1 Main Cabinet Condition	A B C D N U
1.2 Pad Condition	A B C D N U
1.3 Insulators Condition	A B C D N U
1.4 Contact Condition	A B C D N U
1.5 Operating Mechanism Condition	A B C D N U
1.6 Electrical Connections Condition	A B C D N U
1.7 Signs of Over Heating?	A B C D N U
1.7 Overall Condtion	A B C D N U

Cables and Terminations

1.8 Cable Condition	A B C D N U
1.9 Termination Condition	A B C D N U
1.1 Neutral Condition	A B C D N U
1.11 Overall Cable Condition	A B C D N U

2 Pad Mounted Transformer

Location

2.1 Main Cabinet Condition	A B C D N U
2.2 Pad Condition	A B C D N U
2.3 Oil Leaks	A B C D N U
2.4 Operating Temperature	A B C D N U
2.5 Overall Transformer Condition	A B C D N U

Cables and Terminations

2..5 Cable Condition	A B C D N U
2.6 Termination Condition	A B C D N U
2.7 Neutral Condition	A B C D N U
2.8 Overall Cable Condition	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.)

Inspector Name and Date — Name: G [illegible] — Date: Nov 18, 2010

(write any comments or concerns on the back of this form)

5/9/2005 Survey Form 4.8

Asset Condition Survey
Overhead Distribution

Substation		101
Op Desn		102
Age		103
Voltage	4800	104
Location	Pelham Corners	105

Hwy 20 at Victoria

1.0 Remotely Operated Pole Mounted Load Break Switch

	Circle ONLY one	
1.1 Insulator Condition	A B C D N U	109
1.2 Mechanical Support Condition	A B C D N U	110
1.3 Signs of Over Heating?	A B C D N U	111
1.4 Contact Condition	A B C D N U	112
1.5 Operating Mechanism Condition	A B C D N U	113
1.6 Motor Operator and Control Condition	A B C D N U	114
1.7 Overall Condtion	A B C D N U	115

2 Manually Operated Pole Mounted Load Break Switch

1.1 Insulator Condition	A B C D N U	120
1.2 Mechanical Support Condition	A B C D N U	121
1.3 Signs of Over Heating?	A B C D N U	122
1.4 Contact Condition	A B C D N U	123
1.5 Operating Mechanism Condition	A B C D N U	124
1.6 Overall Condtion	A B C D N U	125

3 Pole

Location

1.1 Holes and Cracks ?	A B C D N U	120
1.2 Rot ?	A B C D N U	121
1.3 Cross arm Condition	A B C D N U	122
1.4 Overall Pole Condtion	A B C D N U	125

3 Pole Mounted Transformer

Location

1.1 Tank Integrity	A B C D N U	130
1.2 Oil Leak	A B C D N U	131
1.3 Bushing Condition	A B C D N U	132
1.4 Electrical Connections	A B C D N U	133
1.5 Signs of Overheating?	A B C D N U	135
1.6 Overall Transformer Condition		

Data sources used

Misc inspection record ☐ Interviews ☐ Photos taken (no.) 140

	Name	Date	
Inspector Name and Date	G Ebbeling	Nov 18, 2010	142

(write any comments or concerns on the back of this form)

Appendix B
2006 to 2008 CDM OPA
Conservation Results

OPA Conservation & Demand Management Programs

Allocation Methodology

#	Initiative	Allocation Methodology	Notes
1	2006 Every Kilowatt Counts (Spring)	Measure level allocation based on 2006 residential energy throughput by LDC	
2	2006 Cool Savings	Measure level allocation based on 2006 residential energy throughput by LDC	
3	2006 Secondary Refrigerator Retirement	Measure level allocation based on 2006 residential energy throughput by LDC	
4	2006 Every Kilowatt Counts (Autumn)	Measure level allocation based on 2006 residential energy throughput by LDC	
5	2006 Demand Response 1	Initiative level allocation based on 2006 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population of the Demand Response 1 program can lead to participant confidentiality issues if disclosed on an actual LDC share basis. 2) Program results are based on contracted nameplate capacity and not actual summer coincident peak demand reduction.
6	2007 Great Refrigerator Roundup	Actual LDC specific results	
7	2007 Cool Savings	Measure level allocation based on 2007 residential energy throughput by LDC	
8	2007 Aboriginal	Actual LDC specific results	
9	2007 Every Kilowatt Counts	Measure level allocation based on 2007 residential energy throughput by LDC	
10	2007 ***peaksaver*** ®	Actual LDC specific results	
11	2007 Summer Savings	Allocation determined by evaluation contractor based on residential customers	
12	2007 Affordable Housing	Actual LDC specific results	
13	2007 Social Housing	Initiative level allocation based on 2007 Residential Energy Throughput	
14	2007 Energy Efficiency Assistance for Houses	Actual LDC specific results	
15	2007 Toronto Comprehensive	Program run exclusively in Toronto	
16	2007 Electricity Retrofit Incentive	Actual LDC specific results	
17	2007 Demand Response 1	Initiative level allocation based on 2007 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population of the Demand Response 1 program can lead to participant confidentiality issues if disclosed on an actual LDC share basis. 2) Program results are based on contracted nameplate capacity and not actual summer coincident peak demand reduction.
18	2007 Other Demand Response	Contract level allocation based on 2007 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population of the Other Demand Response program can lead to participant confidentiality issues if disclosed on an actual LDC share basis. 2) Program results are based on contracted nameplate capacity and not actual summer coincident peak demand reduction.
19	2007 Renewable Energy Standard Offer	Actual LDC specific results	Program results are based on contracted nameplate capacity and not actual summer coincident peak generation
20	2008 Great Refrigerator Roundup	Actual LDC specific results	
21	2008 Cool Savings	Measure level allocation based on 2008 Residential Energy Throughput	
22	2008 Aboriginal	Actual LDC specific results	
23	2008 Summer Sweepstakes	Actual LDC specific results	
24	2008 Every Kilowatt Counts Power Savings Event	Measure level allocation based on 2008 Residential Energy Throughput	
25	2008 ***peaksaver*** ®	Actual LDC specific results	
26	2008 Electricity Retrofit Incentive	LDC's respective proportion of province-wide reported gross demand savings.	While this initiative underwent a thorough evaluation process at the provincial level, individual prescriptive input assumptions were not verified for all measures nor were reported savings from every individual LDC verified. A representative sample of retrofit projects were measured and verified and a province-wide savings total was derived. The province wide verified energy and demand savings were allocated to individual LDCs based on their respective proportion of province-wide reported gross demand savings.
27	2008 Toronto Comprehensive	Program run exclusively in Toronto	
28	2008 High Performance New Construction		
29	2008 Power Savings Blitz	Actual LDC specific results	
30	2008 Chiller Plant Re-Commissioning	Actual LDC specific results	
31	2008 Demand Response 1	Initiative level allocation based on 2008 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population of the Demand Response 1 program can lead to participant confidentiality issues if disclosed on an actual LDC share basis. 2) Program results are based on contracted nameplate capacity and not actual summer coincident peak demand reduction.
32	2008 Demand Response 3	Initiative level allocation based on 2008 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population of the Demand Response 3 program can lead to participant confidentiality issues if disclosed on an actual LDC share basis. 2) Program results are based on contracted nameplate capacity and not actual summer coincident peak demand reduction.
33	2008 Other Demand Response	Contract level allocation based on 2008 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population of the Other Demand Response program can lead to participant confidentiality issues if disclosed on an actual LDC share basis. 2) Program results are based on contracted nameplate capacity and not actual summer coincident peak demand reduction.
34	2008 LDC Custom – Hydro One Double Return	Program run exclusively in Hydro One	Verified
35	2008 Renewable Energy Standard Offer	Actual LDC specific results	Program results are based on contracted nameplate capacity and not actual summer coincident peak generation
36	2008 Other Customer Based Generation	Actual LDC specific results	Program results are based on contracted nameplate capacity and not actual summer coincident peak generation

OPA Conservation & Demand Management Programs
Annual Results

For: Niagara Peninsula Energy Inc.

#	Program Name	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012
1	Niagara Peninsula Energy Inc.	2006	Final	2.93	2.93	2.93	0.18	0.18	0.17	0.16
2	Niagara Peninsula Energy Inc.	2007	Final	0.00	2.06	2.06	0.30	0.30	0.30	0.29
3	Niagara Peninsula Energy Inc.	2008	Final	0.00	0.00	3.22	1.86	1.86	1.86	1.86
Total				**3**	**5**	**8**	**2**	**2**	**2**	**2**
4	Province Wide	2006	Final	282.17	282.17	282.17	16.17	16.17	15.27	14.01
5	Province Wide	2007	Final	0.00	300.38	299.91	177.11	177.11	176.15	42.13
6	Province Wide	2008	Final	0.00	0.00	360.73	179.37	179.27	179.27	178.59
Total				**282**	**583**	**943**	**373**	**373**	**371**	**235**

Net														
Summer Peak Demand Savings (MW)														
2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
0.12	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.29	0.29	0.25	0.23	0.21	0.21	0.19	0.19	0.19	0.03	0.03	0.03	0.00	0.00	0.00
1.00	0.99	0.99	0.96	0.94	0.93	0.93	0.92	0.35	0.35	0.31	0.23	0.23	0.11	0.11
1	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**
10.67	10.67	10.67	10.67	10.67	10.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.13	42.13	38.33	37.30	34.83	34.83	21.50	21.50	21.19	5.66	5.63	5.63	2.46	1.95	0.00
93.59	92.29	91.85	87.72	80.98	80.63	80.63	79.52	45.40	45.03	41.23	26.42	26.42	14.41	14.41
146	**145**	**141**	**136**	**126**	**126**	**102**	**101**	**67**	**51**	**47**	**32**	**29**	**16**	**14**

2028	2029	2030	2031	2032
0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00
0	**0**	**0**	**0**	**0**
0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00
0	**0**	**0**	**0**	**0**

2006	2007	2008	2009	2010	2011	2012	2013	2014
4,179	4,179	4,179	4,179	4,179	2,653	2,591	116	116
0	3,687	3,670	1,962	1,962	1,962	1,893	1,885	1,885
0	0	3,031	2,472	2,472	2,472	2,295	2,295	2,112
4,179	**7,866**	**10,881**	**8,613**	**8,613**	**7,087**	**6,780**	**4,296**	**4,113**
374,407	374,407	374,407	374,407	374,407	237,735	232,140	10,417	10,417
0	474,318	472,717	391,717	391,717	371,920	199,587	194,587	194,587
0	0	360,162	335,617	334,553	334,553	316,559	316,378	297,758
374,407	**848,725**	**1,207,285**	**1,101,741**	**1,100,677**	**944,208**	**748,286**	**521,382**	**502,761**

Net													
Annual Energy Savings (MWh)													
2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
116	116	116	116	0	0	0	0	0	0	0	0	0	0
669	532	325	325	325	325	325	46	39	39	4	0	0	0
1,974	1,483	1,274	1,157	1,157	1,139	1,113	1,105	1,028	286	286	104	104	0
2,760	**2,132**	**1,714**	**1,598**	**1,482**	**1,464**	**1,438**	**1,150**	**1,067**	**325**	**290**	**104**	**104**	**0**
10,417	10,417	10,417	10,417	0	0	0	0	0	0	0	0	0	0
77,277	66,358	46,225	46,225	46,225	46,225	41,971	14,937	14,313	14,313	10,907	8,607	0	0
283,825	236,654	196,624	187,191	187,191	184,705	183,376	182,857	171,903	59,667	59,667	41,012	41,012	0
371,519	**313,429**	**253,265**	**243,833**	**233,416**	**230,930**	**225,346**	**197,794**	**186,216**	**73,980**	**70,574**	**49,619**	**41,012**	**0**

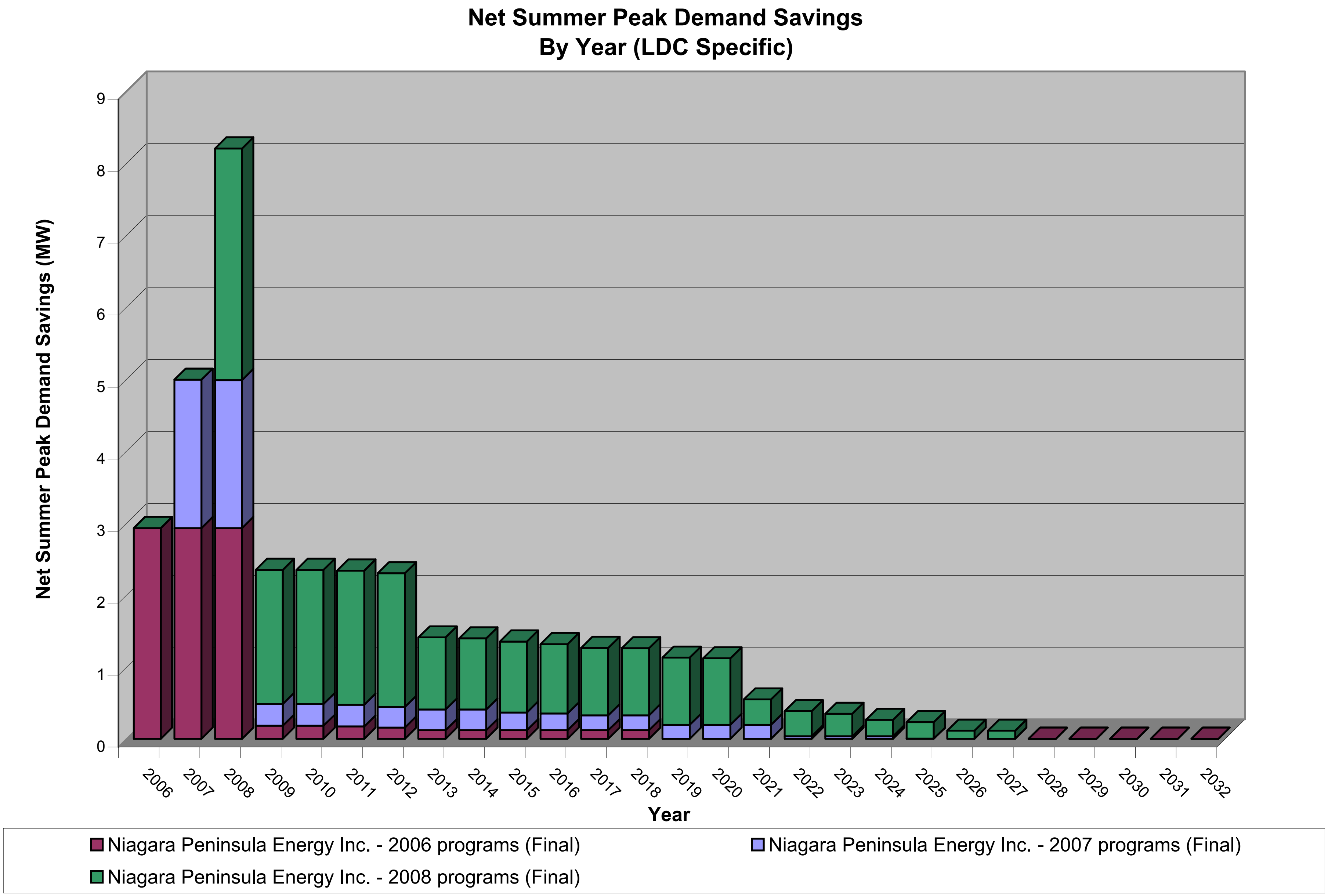
2029	2030	2031	2032
0	0	0	0
0	0	0	0
0	0	0	0
0	**0**	**0**	**0**
0	0	0	0
0	0	0	0
0	0	0	0
0	**0**	**0**	**0**

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2.95	2.95	2.95	0.20	0.20	0.19	0.17	0.13	0.13	0.13	0.13
0.00	9.28	9.27	0.56	0.56	0.56	0.47	0.47	0.47	0.42	0.39
0.00	0.00	3.62	2.24	2.24	2.24	2.22	1.37	1.34	1.33	1.29
3	**12**	**16**	**3**	**3**	**3**	**3**	**2**	**2**	**2**	**2**
283.96	283.96	283.96	17.96	17.96	16.97	15.56	11.86	11.86	11.86	11.86
0.00	671.04	670.17	217.37	217.37	216.41	61.34	61.34	61.34	56.15	53.51
0.00	0.00	405.15	222.12	221.99	221.99	220.21	135.21	132.38	131.21	124.38
284	**955**	**1,359**	**457**	**457**	**455**	**297**	**208**	**206**	**199**	**190**

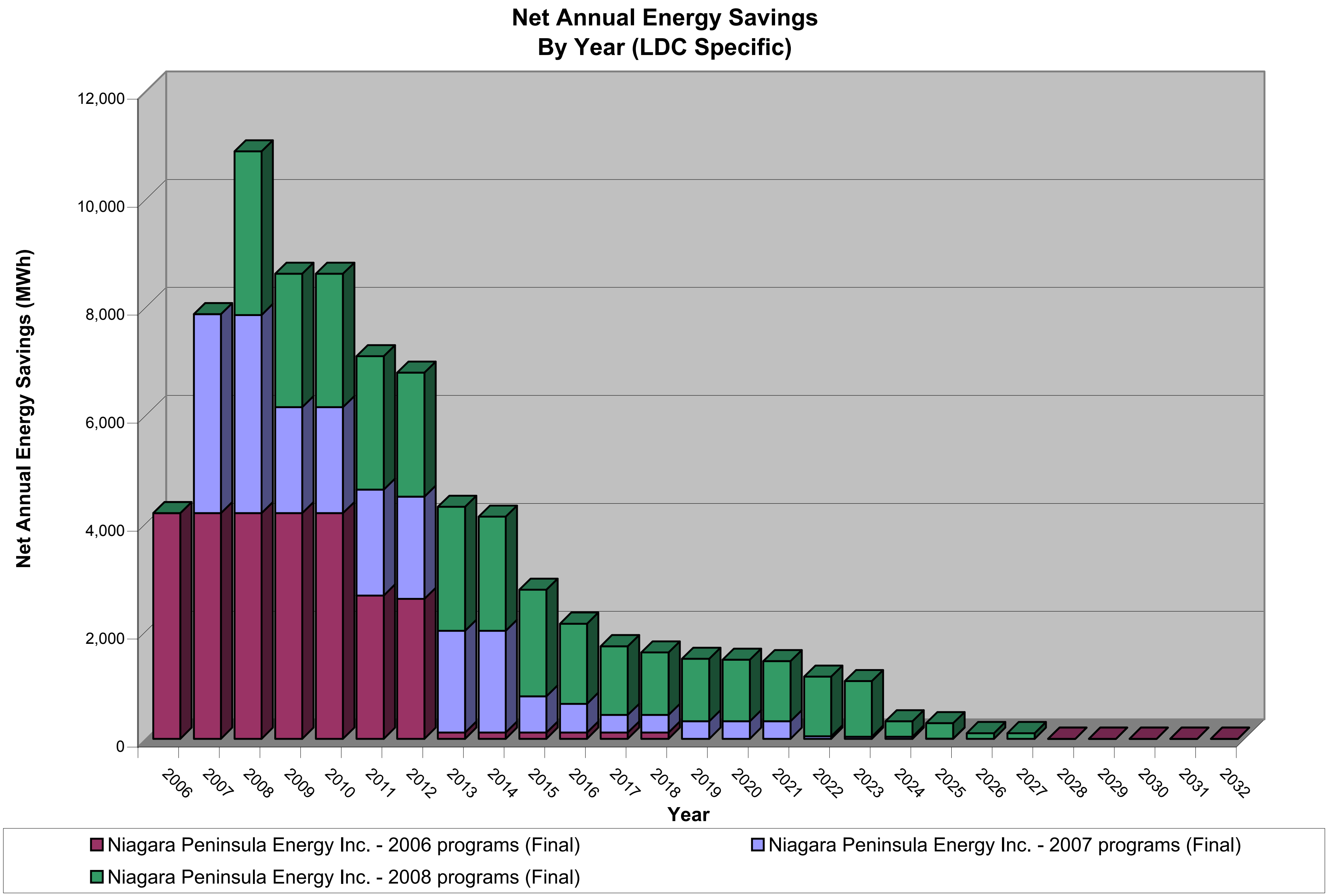
		Gross												
	Summer Peak Demand Savings (MW)													
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
0.13	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.35	0.35	0.34	0.34	0.34	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.24	1.23	1.23	1.20	0.57	0.57	0.51	0.35	0.35	0.14	0.14	0.00	0.00	0.00	0.00
2	**2**	**2**	**2**	**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
11.86	11.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50.18	50.18	35.37	35.37	35.06	8.04	7.99	7.99	2.46	1.95	0.00	0.00	0.00	0.00	0.00
111.36	110.59	110.59	108.10	70.18	69.66	63.43	36.95	36.95	16.08	16.08	0.00	0.00	0.00	0.00
173	**173**	**146**	**143**	**105**	**78**	**71**	**45**	**39**	**18**	**16**	**0**	**0**	**0**	**0**

													G
													Annual Energ
2032	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
0.00	4,643	4,643	4,643	4,643	4,643	2,948	2,879	129	129	129	129	129	129
0.00	0	17,317	17,287	3,052	3,052	3,052	2,780	2,780	2,780	1,187	836	562	562
0.00	0	0	5,834	5,108	5,108	5,108	4,650	4,650	4,240	3,874	3,023	2,640	2,409
0	**4,643**	**21,960**	**27,764**	**12,804**	**12,804**	**11,109**	**10,309**	**7,560**	**7,149**	**5,190**	**3,989**	**3,331**	**3,100**
0.00	416,007	416,007	416,007	416,007	416,007	264,150	257,933	11,574	11,574	11,574	11,574	11,574	11,574
0.00	0	1,189,858	1,186,946	511,946	511,946	492,149	277,077	277,077	277,077	123,786	95,856	69,231	69,231
0.00	0	0	677,605	645,319	643,918	643,918	597,241	596,982	555,334	518,183	434,492	359,600	339,246
0	**416,007**	**1,605,865**	**2,280,559**	**1,573,273**	**1,571,872**	**1,400,217**	**1,132,252**	**885,634**	**843,986**	**653,544**	**541,923**	**440,405**	**420,052**

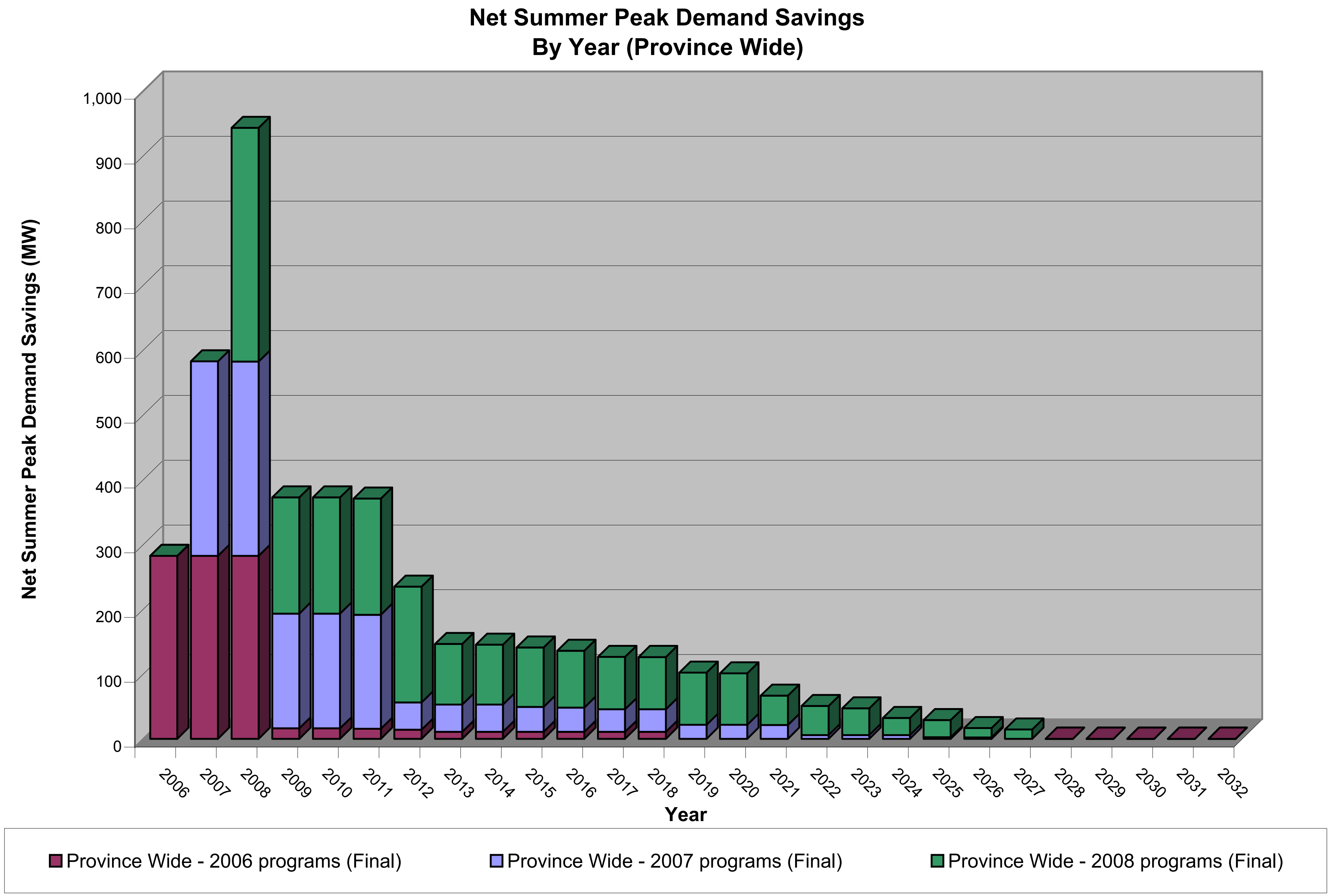
ross													
y Savings (MWh)													
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
0	0	0	0	0	0	0	0	0	0	0	0	0	0
562	562	562	75	63	63	4	0	0	0	0	0	0	0
2,409	2,369	2,337	2,326	2,188	450	450	134	134	0	0	0	0	0
2,971	**2,931**	**2,899**	**2,401**	**2,251**	**513**	**454**	**134**	**134**	**0**	**0**	**0**	**0**	**0**
0	0	0	0	0	0	0	0	0	0	0	0	0	0
69,231	69,231	64,977	17,763	16,629	16,629	10,907	8,607	0	0	0	0	0	0
339,246	334,040	332,452	331,746	313,985	79,645	79,645	47,148	47,148	0	0	0	0	0
408,477	**403,271**	**397,429**	**349,509**	**330,614**	**96,274**	**90,551**	**55,754**	**47,148**	**0**	**0**	**0**	**0**	**0**

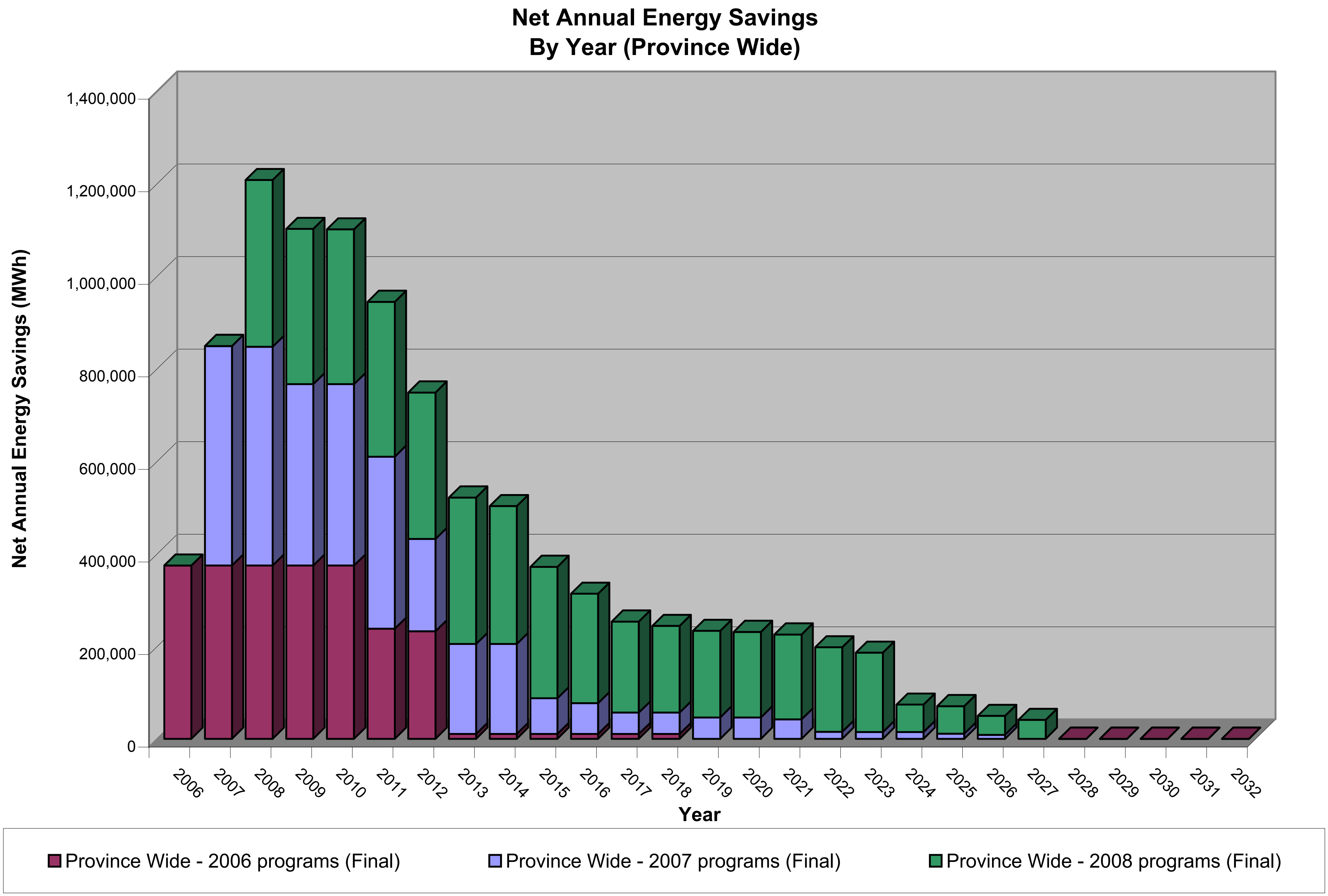


Net Summer Peak Demand Savings
By Year (LDC Specific)
Net Summer Peak Demand Savings (MW)
0
1
2
3
4
5
6
7
8
9
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
Year
Niagara Peninsula Energy Inc. - 2006 programs (Final)
Niagara Peninsula Energy Inc. - 2007 programs (Final)
Niagara Peninsula Energy Inc. - 2008 programs (Final)



Net Annual Energy Savings
By Year (LDC Specific)
Net Annual Energy Savings (MWh)
12,000
10,000
8,000
6,000
4,000
2,000
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
Year
Niagara Peninsula Energy Inc. - 2006 programs (Final)
Niagara Peninsula Energy Inc. - 2007 programs (Final)
Niagara Peninsula Energy Inc. - 2008 programs (Final)


Net Summer Peak Demand Savings
By Year (Province Wide)
Net Summer Peak Demand Savings (MW)
1,000
900
800
700
600
500
400
300
200
100
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
Year
Province Wide - 2006 programs (Final)
Province Wide - 2007 programs (Final)
Province Wide - 2008 programs (Final)



Net Annual Energy Savings
By Year (Province Wide)
Net Annual Energy Savings (MWh)
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
Year
Province Wide - 2006 programs (Final)
Province Wide - 2007 programs (Final)
Province Wide - 2008 programs (Final)

OPA Conservation & Demand Management Programs

Initiative Results

For: Niagara Peninsula Energy Inc.

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Annual Energy Savings (MWh)					
						2006	2007	2008	2009	2010	2011
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	1,525	1,525	1,525	1,525	1,525	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	116	116	116	116	116	116
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	62	62	62	62	62	62
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	2,475	2,475	2,475	2,475	2,475	2,475
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
2006 Subtotal						**4,179**	**4,179**	**4,179**	**4,179**	**4,179**	**2,653**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	170	170	170	170	170
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	311	311	311	311	311
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	1,362	1,345	1,345	1,345	1,345
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	1,708	1,708	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	123	123	123	123	123
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	4	4	4	4	4
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	0	9	9	9	9	9
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0
2007 Subtotal						**0**	**3,687**	**3,670**	**1,962**	**1,962**	**1,962**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	268	268	268	268
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	228	228	228	228
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0	0	868	313	313	313
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	1,171	1,166	1,166	1,166
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	11	11	11	11
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0	0	482	482	482	482
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	3	3	3	3
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
2008 Subtotal						**0**	**0**	**3,031**	**2,472**	**2,472**	**2,472**
Overall Total						**4,179**	**7,866**	**10,881**	**8,613**	**8,613**	**7,087**

Province Wide Results

#	Initiative Name	Program Name	Program Year	Results Status	Net Annual Energy Savings (MWh)					
					2006	2007	2008	2009	2010	2011
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	136,671.67	136,671.67	136,671.67	136,671.67	136,671.67	0.00
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	10,417.00	10,417.00	10,417.00	10,417.00	10,417.00	10,417.00
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	5,595.21	5,595.21	5,595.21	5,595.21	5,595.21	5,595.21
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	221,722.84	221,722.84	221,722.84	221,722.84	221,722.84	221,722.84
6	2006 Demand Response 1	Industrial, Business	2006	Final	0.00	0.00	0.00	0.00	0.00	0.00
2006 Subtotal					**374,407**	**374,407**	**374,407**	**374,407**	**374,407**	**237,735**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	0	13,539	13,539	13,539	13,539	13,539
8	2007 Cool Savings Rebate	Consumer	2007	Final	0	30,191	30,191	30,191	30,191	30,191
9	2007 Aboriginal – Pilot	Consumer	2007	Final	0	19,797	19,797	19,797	19,797	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	0	132,041	130,440	130,440	130,440	130,440

11	2007 peaksaver®	Consumer, Business	2007	Final	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	0	81,000	81,000	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	0	4,254	4,254	4,254	4,254	4,254
14	2007 Social Housing – Pilot	Consumer	2007	Final	0	11,900	11,900	11,900	11,900	11,900
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	0	2,300	2,300	2,300	2,300	2,300
16	2007 Toronto Comprehensive	Business	2007	Final	0	165,690	165,690	165,690	165,690	165,690
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	0	5,000	5,000	5,000	5,000	5,000
18	2007 Demand Response 1	Industrial, Business	2007	Final	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	0	8,607	8,607	8,607	8,607	8,607
2007 Subtotal					**0**	**474,318**	**472,717**	**391,717**	**391,717**	**371,920**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	0	0	34,024	34,024	34,024	34,024
22	2008 Cool Savings Rebate	Consumer	2008	Final	0	0	23,393	23,393	23,393	23,393
23	2008 Aboriginal	Consumer	2008	Final	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	0	0	37,551	13,550	13,550	13,550
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	0	0	118,754	118,237	118,237	118,237
26	2008 peaksaver®	Consumer, Business	2008	Final	0	0	681	681	681	681
27	2008 Electricity Retrofit Incentive	Business	2008	Final	0	0	54,593	54,593	54,593	54,593
28	2008 Toronto Comprehensive	Business	2008	Final	0	0	58,059	58,032	57,546	57,546
29	2008 High Performance New Construction	Business	2008	Final	0	0	287	287	287	287
30	2008 Power Savings Blitz	Business	2008	Final	0	0	3,205	3,205	2,627	2,627
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	2,118	2,118	2,118	2,118
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	0	0	27,498	27,498	27,498	27,498
2008 Subtotal					**0**	**0**	**360,162**	**335,617**	**334,553**	**334,553**
Overall Total					**374,407**	**848,725**	**1,207,285**	**1,101,741**	**1,100,677**	**944,208**

OPA Conservation & Demand Management Programs

Measure Results

For: Niagara Peninsula Energy Inc.

#	Initiative Name	Program Name	Program Year	Results Status
2006				
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final
2	2006 Cool Savings Rebate Program	Consumer	2006	Final
2	2006 Cool Savings Rebate Program	Consumer	2006	Final
2	2006 Cool Savings Rebate Program	Consumer	2006	Final
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final
6	2006 Demand Response 1	Industrial, Business	2006	Final
2007				
7	2007 Great Refrigerator Roundup	Consumer	2007	Final
7	2007 Great Refrigerator Roundup	Consumer	2007	Final
7	2007 Great Refrigerator Roundup	Consumer	2007	Final
7	2007 Great Refrigerator Roundup	Consumer	2007	Final
7	2007 Great Refrigerator Roundup	Consumer	2007	Final
8	2007 Cool Savings Rebate	Consumer	2007	Final
8	2007 Cool Savings Rebate	Consumer	2007	Final
8	2007 Cool Savings Rebate	Consumer	2007	Final
8	2007 Cool Savings Rebate	Consumer	2007	Final
9	2007 Aboriginal – Pilot	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
10	2007 Every Kilowatt Counts	Consumer	2007	Final
11	2007 peaksaver®	Consumer, Business	2007	Final
11	2007 peaksaver®	Consumer, Business	2007	Final
11	2007 peaksaver®	Consumer, Business	2007	Final
11	2007 peaksaver®	Consumer, Business	2007	Final

11	2007 peaksaver®	Consumer, Business	2007	Final
11	2007 peaksaver®	Consumer, Business	2007	Final
12	2007 Summer Savings	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
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13	2007 Affordable Housing – Pilot	Consumer	2007	Final
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13	2007 Affordable Housing – Pilot	Consumer	2007	Final
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13	2007 Affordable Housing – Pilot	Consumer	2007	Final
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13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
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13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
13	2007 Affordable Housing – Pilot	Consumer	2007	Final
14	2007 Social Housing – Pilot	Consumer	2007	Final
15	2007 Energy Efficiency Assistance for House	Consumer	2007	Final
16	2007 Toronto Comprehensive	Business	2007	Final
16	2007 Toronto Comprehensive	Business	2007	Final
16	2007 Toronto Comprehensive	Business	2007	Final
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final
18	2007 Demand Response 1	Industrial, Business	2007	Final
19	2007 Other Demand Response	Industrial, Business	2007	Final
19	2007 Other Demand Response	Industrial, Business	2007	Final
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final

2008				
21	2008 Great Refrigerator Roundup	Consumer	2008	Final
21	2008 Great Refrigerator Roundup	Consumer	2008	Final
21	2008 Great Refrigerator Roundup	Consumer	2008	Final
22	2008 Cool Savings Rebate	Consumer	2008	Final
22	2008 Cool Savings Rebate	Consumer	2008	Final
22	2008 Cool Savings Rebate	Consumer	2008	Final
22	2008 Cool Savings Rebate	Consumer	2008	Final
22	2008 Cool Savings Rebate	Consumer	2008	Final
22	2008 Cool Savings Rebate	Consumer	2008	Final
22	2008 Cool Savings Rebate	Consumer	2008	Final

23	2008 Aboriginal	Consumer	2008	Final
24	2008 Summer Sweepstakes	Consumer	2008	Final
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Final
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Final
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Final
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Final
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25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Final
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Final
25	2008 Every Kilowatt Counts Power Savings E	Consumer	2008	Final
26	2008 peaksaver®	Consumer, Business	2008	Final
26	2008 peaksaver®	Consumer, Business	2008	Final
26	2008 peaksaver®	Consumer, Business	2008	Final
26	2008 peaksaver®	Consumer, Business	2008	Final
26	2008 peaksaver®	Consumer, Business	2008	Final
26	2008 peaksaver®	Consumer, Business	2008	Final
27	2008 Electricity Retrofit Incentive	Business	2008	Final
27	2008 Electricity Retrofit Incentive	Business	2008	Final
27	2008 Electricity Retrofit Incentive	Business	2008	Final
27	2008 Electricity Retrofit Incentive	Business	2008	Final
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27	2008 Electricity Retrofit Incentive	Business	2008	Final
27	2008 Electricity Retrofit Incentive	Business	2008	Final
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27	2008 Electricity Retrofit Incentive	Business	2008	Final
27	2008 Electricity Retrofit Incentive	Business	2008	Final
27	2008 Electricity Retrofit Incentive	Business	2008	Final
28	2008 Toronto Comprehensive	Business	2008	Final
28	2008 Toronto Comprehensive	Business	2008	Final
28	2008 Toronto Comprehensive	Business	2008	Final
29	2008 High Performance New Construction	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
30	2008 Power Savings Blitz	Business	2008	Final
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final
32	2008 Demand Response 1	Industrial, Business	2008	Final
33	2008 Demand Response 3	Industrial, Business	2008	Final
34	2008 Other Demand Response	Industrial, Business	2008	Final
34	2008 Other Demand Response	Industrial, Business	2008	Final
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final

#	Measure Name	Unit Savings Assumptions		
		Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)	Effective Useful Life (EUL)
1	Energy Star® Compact Fluorescent Light Bulb	0.00	104	4
2	Electric Timers	0.00	183	20
3	Programmable Thermostats	0.05	216	15
4	Energy Star® Ceiling Fans	0.01	141	20
1	Energy Star® Air Conditioner	0.36	351	14
2	Programmable Thermostats	0.16	159	18
3	Air Conditioner Tune-Up	0.38	369	8
1	Refrigerator Retirement	0.27	1,200	6
2	Freezer Retirement	0.20	900	6
1	Energy Star® Compact Fluorescent Light Bulb	0.00	104	4
2	Seasonal Light Emitting Diode Light String	0.00	31	30
3	Programmable Thermostats	0.12	522	18
4	Dimmers	0.00	139	10
5	Indoor Motion Sensors	0.00	209	20
6	Programmable Basebaord Thermostats	0.00	1,466	18
1	Voluntary Load Shedding Project	Custom	Custom	3
1	Refrigerator	0.07	745	9
2	Freezer	0.07	515	8
3	Small Refrigerator	0.05	490	9
4	Small Freezer	0.04	339	8
5	Window Air Conditioner	0.56	240	5
1	ENERGY STAR® Central Air Conditioner	0.17	152	18
2	Programmable Thermostat	0.03	55	15
3	Furnace with Electronically Commutated Motor	0.49	832	15
4	Central Air Conditioning Tune Up	0.26	235	5
1	Consumer Retrofit Kit	0.04	900	4
1	15 W CFL	0.00	43	8
2	20 W+ CFLs	0.00	62	8
3	Project Porchlight CFLs	0.00	43	8
4	Energy Star Ceiling Fan	0.00	90	10
5	Furnace Filter	0.01	38	1
6	Solar Lights	0.00	33	5
7	Outdoor Motion Sensor	0.00	160	10
8	Dimmer Switch	0.00	24	10
9	Energy Star Light Fixtures	0.01	123	16
10	SLEDs	0.00	14	5
11	T8	0.00	37	18
12	Programmable Thermostat	0.00	75	15
13	Power Bar with Timer	0.01	72	10
14	Lighting Control Devices	0.02	72	10
1	Residential Programmable Thermostat	0.63	0	12
2	Residential Air Conditioner Switch	0.63	0	12
3	Residential Water Heater Switch	0.30	0	12
4	Commercial Programmable Thermostat	4.00	0	12

5	Commercial Air Conditioner Switch	4.00	0	12
6	Commercial Water Heater Switch	0.30	0	12
1	Household	0.44	787	2
1	1 - T8 32W w/EL ballast	0.01	30	14
2	2 - T8 32W w/EL ballast	0.02	46	14
3	Air-source Heat Pump - Split	6.08	4,437	14
4	Automated Controls for HVAC	0.00	18,565	14
5	Boiler	0.01	17	14
6	Ceiling Fan (common area)	0.00	7	14
7	Ceiling Fan (in-suite)	0.00	7	14
8	Central Air Conditioning System - Single	1.07	807	14
9	Central Air Conditioning System - Split	1.94	1,456	14
10	CFL Screw-In 15W - in suite	0.01	180	14
11	CFL Screw-In 25W - in suite	0.01	300	14
12	Dimmer Switch	0.00	139	14
13	Energy Star Clotheswasher	0.03	287	14
14	Energy Star Dishwasher	0.01	136	14
15	Energy Star Refrigerator	0.01	69	14
16	Flood Light, 26W Fluorescent Fixture	0.01	128	14
17	Front Loading Washing Machine	0.11	1,108	14
18	Furnace	0.02	25	14
19	Furnace with DC Motor	0.03	45	14
20	Ground-source Heat Pump	4.71	3,545	14
21	High Pressure Sodium	0.09	749	14
22	Motion Detector	0.00	209	14
23	Occupancy Sensors	0.00	209	14
24	Other CFL Screw-in Light (please specify)	0.01	383	14
25	Other Exterior Lighting (please specify)	0.01	160	14
26	Other Parking Garage Lighting (please specify)	0.05	442	14
27	Photo Sensors	0.00	292	14
28	Programmable Thermostat	0.01	631	14
29	Timer - Outdoor Light	0.00	292	14
30	Ventilating Fan (in-suite)	0.00	12	14
1	Custom Retrofit Projects	Custom	Custom	10
1	Custom Retrofit Projects	Custom	Custom	19
1	City of Toronto - Better Building Partnership Project	Custom	Custom	5
2	Toronto Hydro - Business Incentive Program Project	Custom	Custom	5
3	Building Owners & Managers Association - Toronto Proj	Custom	Custom	5
1	Custom Retrofit Projects	Custom	Custom	5
1	Voluntary Load Shedding Project	Custom	Custom	2
1	Loblaw Contract	Custom	Custom	2
2	Rodan Contract	Custom	Custom	2
1	Hydro	Custom	Custom	20
2	Wind	Custom	Custom	20
3	Solar Photo-Voltaic	Custom	Custom	20
4	Bio-Energy	Custom	Custom	20

1	Refrigerator	0.08	775	9
2	Freezer	0.08	740	8
3	Room Air Conditioner	0.20	197	4.5
1	2007 Efficient Furnance with Electronically Commutable	0.50	837	15
2	2007 ENERGYSTAR® Central Air Conditioner	0.17	155	18
3	2007 Programable Thermostat	0.03	54	15
4	2007 Central Air Conditioner Tune-ups	0.26	235	5
5	2008 Efficient Furnance with Electronically Commutable	0.49	819	18
6	2008 ENERGYSTAR® Central Air Conditioner	0.14	125	18
7	2008 Programable Thermostat	0.03	54	18

1	Building Retrofits	1.60	2,820	10
1	Households	0.20	768	1
1	Air Conditioner/Furnace Filters	0.02	38	1
2	Energy Star® Qualified Compact Fluorescent Floods (In	0.00	88	7
3	Energy Star® Qualified Light Fixtures	0.00	133	16
4	Heavy Duty Timers	0.02	301	10
5	T8 Fluorescent Fixtures	0.00	37	16
6	ENERGY STAR Decorative CFLs	0.00	30	4
7	ENERGY STAR Dimmable CFLs	0.00	98	6
8	Power Bars with Timers	0.00	53	10
9	Programmable Thermostats - Baseboard	0.00	64	15
10	Car block heater timer	n/a	n/a	n/a
11	Energy Star® Qualified Compact Fluorescent Light Bulb	0.00	53	8
12	Lighting Control Devices	0.00	102	10
13	Awnings	0.00	0	n/a
14	Window Films	0.00	0	n/a
15	Electric Water Heater Blankets	0.00	0	n/a
16	Pipe Wrap	0.00	38	6
17	Low-Flow Toilets	0.00	0	n/a
18	Keep Cool – Dehumidifier	0.29	500	12
19	Keep Cool – Room Air Conditioner	0.14	141	9
20	Rewards for Recycling – Dehumidifier	0.29	500	12
21	Rewards for Recycling – Room Air Conditioner	0.14	141	9
22	Rewards for Recycling - Halogen Lamp	0.01	275	16
1	Residential Programmable Thermostat	0.87	17	13
2	Residential Air Conditioner Switch	0.87	17	13
3	Residential Water Heater Switch	0.30	6	13
4	Commercial Programmable Thermostat	3.70	74	13
5	Commercial Air Conditioner Switch	3.70	74	13
6	Commercial Water Heater Switch	1.85	37	13
1	Agribusiness ENERGY STAR® Rated Exit Signs, All siz	n/a	n/a	n/a
2	Agribusiness ENERGY STAR® Rated CFLs, Screw in.	n/a	n/a	n/a
3	Agribusiness ENERGY STAR® Rated CFLs, Hard wired	n/a	n/a	n/a
4	Agribusiness Standard Performance T8, Single lamp sta	n/a	n/a	n/a
5	Agribusiness Standard Performance T8, Double lamp st	n/a	n/a	n/a
6	Agribusiness Standard Performance T8, Triple lamp star	n/a	n/a	n/a
7	Agribusiness Standard Performance T8, Quadruple lamp	n/a	n/a	n/a
8	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a	n/a
9	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a	n/a
10	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a	n/a
11	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a	n/a
12	Agribusiness T5 Fixtures, T5 fixture with 1, 2, or 3 lamps	n/a	n/a	n/a
13	Agribusiness T5 Fixtures, High Bay T5. Maximum 6 lam	n/a	n/a	n/a
14	Agribusiness Metal Halide, 320 W Ceramic pulse start	n/a	n/a	n/a
15	Agribusiness Occupancy Sensors, Switch plate mounted	n/a	n/a	n/a
16	Agribusiness Occupancy Sensors, Ceiling mounted occu	n/a	n/a	n/a
17	Agribusiness Creep Heat Pads, up to 100W maximum	n/a	n/a	n/a
18	Agribusiness Creep Heat Pads, up to 200W maximum	n/a	n/a	n/a
19	Agribusiness High Temperature Cutout Thermostat	n/a	n/a	n/a
20	Agribusiness Creep Heat Controller	n/a	n/a	n/a
21	Agribusiness Energy Efficient Ventilation Exhaust Fans	n/a	n/a	n/a
22	Agribusiness Low Energy Livestock Waterers	n/a	n/a	n/a
23	Agribusiness Photocell and Timer for Lighting Control	n/a	n/a	n/a
24	Lighting System Exit Signs, 5 W or less	n/a	n/a	n/a
25	Lighting System ENERGY STAR® Rated CFLs, Screw i	n/a	n/a	n/a
26	Lighting System ENERGY STAR® Rated CFLs, Hard wi	n/a	n/a	n/a
27	Lighting System Standard Performance T8, Single lamp	n/a	n/a	n/a
28	Lighting System Standard Performance T8, Double lamp	n/a	n/a	n/a

29	Lighting System Standard Performance T8, Triple lamp	n/a	n/a	n/a
30	Lighting System Standard Performance T8, Quadruple la	n/a	n/a	n/a
31	Lighting System High Performance T8 (Consortium for E	n/a	n/a	n/a
32	Lighting System High Performance T8 (Consortium for E	n/a	n/a	n/a
33	Lighting System High Performance T8 (Consortium for E	n/a	n/a	n/a
34	Lighting System High Performance T8 (Consortium for E	n/a	n/a	n/a
35	Lighting System T5 Fixtures, T5 fixture with 1, 2, or 3 lar	n/a	n/a	n/a
36	Lighting System T5 Fixtures, High Bay T5. Maximum 6	n/a	n/a	n/a
37	Lighting System Metal Halide, 320 W Ceramic pulse star	n/a	n/a	n/a
38	Lighting System Occupancy Sensors, Switch plate mour	n/a	n/a	n/a
39	Lighting System Occupancy Sensors, Ceiling mounted c	n/a	n/a	n/a
40	Motor Open Drip-Proof (ODP), 1 HP	n/a	n/a	n/a
41	Motor Open Drip-Proof (ODP), 1.5 HP	n/a	n/a	n/a
42	Motor Open Drip-Proof (ODP), 2 HP	n/a	n/a	n/a
43	Motor Open Drip-Proof (ODP), 3 HP	n/a	n/a	n/a
44	Motor Open Drip-Proof (ODP), 5 HP	n/a	n/a	n/a
45	Motor Open Drip-Proof (ODP), 7.5 HP	n/a	n/a	n/a
46	Motor Open Drip-Proof (ODP), 10 HP	n/a	n/a	n/a
47	Motor Open Drip-Proof (ODP), 15 HP	n/a	n/a	n/a
48	Motor Open Drip-Proof (ODP), 20 HP	n/a	n/a	n/a
49	Motor Open Drip-Proof (ODP), 25 HP	n/a	n/a	n/a
50	Motor Open Drip-Proof (ODP), 30 HP	n/a	n/a	n/a
51	Motor Open Drip-Proof (ODP), 40 HP	n/a	n/a	n/a
52	Motor Open Drip-Proof (ODP), 50 HP	n/a	n/a	n/a
53	Motor Open Drip-Proof (ODP), 60 HP	n/a	n/a	n/a
54	Motor Open Drip-Proof (ODP), 75 HP	n/a	n/a	n/a
55	Motor Open Drip-Proof (ODP), 100 HP	n/a	n/a	n/a
56	Motor Open Drip-Proof (ODP), 125 HP	n/a	n/a	n/a
57	Motor Open Drip-Proof (ODP), 150 HP	n/a	n/a	n/a
58	Motor Open Drip-Proof (ODP), 200 HP	n/a	n/a	n/a
59	Motor Totally Enclosed Fan-Cooled (TEFC), 1 HP	n/a	n/a	n/a
60	Motor Totally Enclosed Fan-Cooled (TEFC), 1.5 HP	n/a	n/a	n/a
61	Motor Totally Enclosed Fan-Cooled (TEFC), 2 HP	n/a	n/a	n/a
62	Motor Totally Enclosed Fan-Cooled (TEFC), 3 HP	n/a	n/a	n/a
63	Motor Totally Enclosed Fan-Cooled (TEFC), 5 HP	n/a	n/a	n/a
64	Motor Totally Enclosed Fan-Cooled (TEFC), 7.5 HP	n/a	n/a	n/a
65	Motor Totally Enclosed Fan-Cooled (TEFC), 10 HP	n/a	n/a	n/a
66	Motor Totally Enclosed Fan-Cooled (TEFC), 15 HP	n/a	n/a	n/a
67	Motor Totally Enclosed Fan-Cooled (TEFC), 20 HP	n/a	n/a	n/a
68	Motor Totally Enclosed Fan-Cooled (TEFC), 25 HP	n/a	n/a	n/a
69	Motor Totally Enclosed Fan-Cooled (TEFC), 30 HP	n/a	n/a	n/a
70	Motor Totally Enclosed Fan-Cooled (TEFC), 40 HP	n/a	n/a	n/a
71	Motor Totally Enclosed Fan-Cooled (TEFC), 50 HP	n/a	n/a	n/a
72	Motor Totally Enclosed Fan-Cooled (TEFC), 60 HP	n/a	n/a	n/a
73	Motor Totally Enclosed Fan-Cooled (TEFC), 75 HP	n/a	n/a	n/a
74	Motor Totally Enclosed Fan-Cooled (TEFC), 100 HP	n/a	n/a	n/a
75	Motor Totally Enclosed Fan-Cooled (TEFC), 125 HP	n/a	n/a	n/a
76	Motor Totally Enclosed Fan-Cooled (TEFC), 150 HP	n/a	n/a	n/a
77	Motor Totally Enclosed Fan-Cooled (TEFC), 200 HP	n/a	n/a	n/a
78	Transformer Size 15	n/a	n/a	n/a
79	Transformer Size 30	n/a	n/a	n/a
80	Transformer Size 45	n/a	n/a	n/a
81	Transformer Size 75	n/a	n/a	n/a
82	Transformer Size 112.5	n/a	n/a	n/a
83	Transformer Size 150	n/a	n/a	n/a
84	Transformer Size 225	n/a	n/a	n/a
85	Transformer Size 300	n/a	n/a	n/a
86	Transformer Size 500	n/a	n/a	n/a

87	Transformer Size 750	n/a	n/a	n/a
88	Transformer Size 1000	n/a	n/a	n/a
89	Unitary AC Single Phase <= 5.4 Tons	n/a	n/a	n/a
90	Unitary AC 3 Phase <= 5.4 Tons	n/a	n/a	n/a
91	Unitary AC >5.4 & <= 11.25 tons	n/a	n/a	n/a
92	Unitary AC >11.25 & <= 20 tons	n/a	n/a	n/a
93	Unitary AC 25 tons	n/a	n/a	n/a
94	Custom	n/a	n/a	n/a
1	City of Toronto - Better Building Partnership Project	Custom	Custom	Custom
2	Toronto Hydro - Business Incentive Program Project	Custom	Custom	Custom
3	Building Owners & Managers Association - Toronto Proj	Custom	Custom	Custom
1	Custom New Construction Project	Custom	Custom	14
1	T8 Fixture With Electronic Balllast	0.02	151	15
2	Energy Star® rated LED Exit Sign	0.03	237	16
3	Energy Star® rated CLF	0.03	191	2
4	Electric Water Heater Tank Wrap	0.05	436	7
5	Electric Water Heater Pipe Insulation	0.03	277	15
6	Aerator	0.03	310	5
7	Halogen	1.96	14	1
8	Other	0.00	0	0
1	Mixed Use Facility	TBD	TBD	TBD
2	University Campus	TBD	TBD	TBD
3	Hospital	TBD	TBD	TBD
4	Commercial Office Tower	TBD	TBD	TBD
5	Industrial/Manufacturing Facility	TBD	TBD	TBD
6	City Government Central Utilities Plant	TBD	TBD	TBD
7	Hotel	TBD	TBD	TBD
1	Voluntary Load Shedding Project	Custom	Custom	1
1	Contractual Load Shedding Project	Custom	Custom	5
1	Loblaw Contract	Custom	Custom	1
2	Rodan Contract	Custom	Custom	1
1	Hydro One Networks - Double Return	52,000.00	0	1
1	Hydro	Custom	Custom	20
2	Wind	Custom	Custom	20
3	Solar Photo-Voltaic	Custom	Custom	20
4	Bio-Energy	Custom	Custom	20
1	Combined Heat & Power / By-Product	Custom	Custom	20

Net-to-Gross Adjustments (%)								
Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)	Provincial Total (# Units)	LDC Total (# Units)	Calc
90%	100%	100%	100%	100%	90%	1,338,276	14,937	1,403,480
90%	100%	100%	100%	100%	90%	37,518	419	68,969
90%	100%	100%	100%	100%	90%	16,320	182	35,411
90%	100%	100%	100%	100%	90%	12,415	139	17,584
90%	100%	100%	100%	100%	90%	14,393	161	56,387
90%	100%	100%	100%	100%	90%	10,965	122	19,459
90%	100%	100%	100%	100%	90%	9,816	110	40,428
90%	100%	100%	100%	100%	90%	5,018	56	60,488
90%	100%	100%	100%	100%	90%	217	2	1,962
90%	100%	100%	100%	100%	90%	1,984,267	22,147	2,080,946
90%	100%	100%	100%	100%	90%	477,612	5,331	147,530
90%	100%	100%	100%	100%	90%	31,484	351	165,119
90%	100%	100%	100%	100%	90%	0	278	34,761
90%	100%	100%	100%	100%	90%	0	100	18,754
90%	100%	100%	100%	100%	90%	1,875	21	27,621
100%	100%	100%	100%	100%	100%	n/a	n/a	4,178,900
48%	100%	100%	81%	100%	39%	37,123	466	135,991
50%	100%	100%	91%	100%	46%	10,652	133	31,314
38%	100%	100%	79%	100%	30%	581	7	1,031
38%	100%	100%	79%	100%	30%	325	4	407
43%	100%	100%	100%	100%	43%	758	8	829
52%	5%	100%	100%	100%	57%	33,178	342	29,791
46%	0%	60%	100%	100%	27%	46,989	485	7,270
54%	5%	100%	100%	100%	59%	51,990	536	263,632
42%	0%	38%	100%	100%	16%	28,048	289	10,704
100%	100%	100%	100%	100%	100%	21,997	0	-
78%	100%	100%	100%	100%	78%	2,376,053	24,508	821,984
78%	100%	100%	100%	100%	78%	386,799	3,990	193,248
76%	100%	100%	100%	100%	76%	500,000	5,157	168,537
55%	100%	100%	100%	100%	55%	19,166	198	9,764
55%	100%	100%	100%	100%	55%	77,226	797	16,516
13%	100%	100%	100%	100%	13%	305,048	3,146	13,416
55%	100%	100%	100%	100%	55%	30,516	315	27,664
55%	100%	100%	100%	100%	55%	19,390	200	2,607
55%	100%	100%	100%	100%	55%	9,229	95	6,434
49%	100%	100%	100%	100%	49%	629,498	6,493	43,587
77%	100%	100%	100%	100%	77%	18,088	187	5,344
55%	100%	100%	100%	100%	55%	18,633	192	7,938
77%	100%	100%	100%	100%	77%	8,442	87	4,854
55%	100%	100%	100%	100%	55%	97,742	1,008	40,034
90%	100%	100%	100%	100%	90%	12,360	16	-
90%	100%	100%	100%	100%	90%	3,733	7	-
90%	100%	100%	100%	100%	90%	10,364	0	
90%	100%	100%	100%	100%	90%	167	0	

90%	100%	100%	100%	100%	90%	221	0	
90%	100%	100%	100%	100%	90%	9	0	
12%	100%	100%	100%	100%	12%	858,039	18,094	1,708,135
100%	100%	100%	100%	100%	100%	174	0	
100%	100%	100%	100%	100%	100%	328	0	
100%	100%	100%	100%	100%	100%	4	0	
100%	100%	100%	100%	100%	100%	154	0	
100%	100%	100%	100%	100%	100%	78	0	
100%	100%	100%	100%	100%	100%	11	0	
100%	100%	100%	100%	100%	100%	12	0	
100%	100%	100%	100%	100%	100%	75	0	
100%	100%	100%	100%	100%	100%	15	0	
100%	100%	100%	100%	100%	100%	920	0	
100%	100%	100%	100%	100%	100%	143	0	
100%	100%	100%	100%	100%	100%	68	0	
100%	100%	100%	100%	100%	100%	23	0	
100%	100%	100%	100%	100%	100%	2	0	
100%	100%	100%	100%	100%	100%	448	0	
100%	100%	100%	100%	100%	100%	30	0	
100%	100%	100%	100%	100%	100%	43	0	
100%	100%	100%	100%	100%	100%	36	0	
100%	100%	100%	100%	100%	100%	5	0	
100%	100%	100%	100%	100%	100%	26	0	
100%	100%	100%	100%	100%	100%	10	0	
100%	100%	100%	100%	100%	100%	35	0	
100%	100%	100%	100%	100%	100%	163	0	
100%	100%	100%	100%	100%	100%	1,902	0	
100%	100%	100%	100%	100%	100%	34	0	
100%	100%	100%	100%	100%	100%	104	0	
100%	100%	100%	100%	100%	100%	6	0	
100%	100%	100%	100%	100%	100%	57	0	
100%	100%	100%	100%	100%	100%	19	0	
100%	100%	100%	100%	100%	100%	48	0	
100%	100%	100%	100%	100%	100%	9,680	100	122,741
100%	100%	100%	100%	100%	100%	544	5	12,908
90%	100%	100%	100%	100%	90%	0	0	
90%	100%	100%	100%	100%	90%	24	0	
90%	100%	100%	100%	100%	90%	12	0	
90%	100%	100%	100%	100%	90%	n/a	n/a	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	4	0	
100%	100%	100%	100%	100%	100%	3	0	
100%	100%	100%	100%	100%	100%	72	0	
100%	100%	100%	100%	100%	100%	2	0	3,686,683

55%	100%	100%	100%	100%	55%	62,968	479	204,174
52%	100%	100%	100%	100%	52%	18,376	166	63,877
36%	100%	100%	100%	100%	36%	1,587	6	426
54%	5%	100%	100%	100%	59%	9,366	91	45,133
52%	5%	100%	100%	100%	57%	4,499	44	3,894
46%	0%	60%	100%	100%	27%	7,291	71	1,048
16%	0%	100%	100%	100%	16%	0	0	-
54%	5%	100%	100%	100%	59%	33,546	327	158,275
52%	5%	100%	100%	100%	57%	22,241	217	15,529
46%	0%	60%	100%	100%	27%	28,505	278	4,097

100%	100%	100%	100%	100%	100%	0	0	-
78%	100%	100%	100%	100%	78%	62,670	1,448	867,614
35%	100%	100%	100%	100%	35%	39,053	385	5,093
37%	100%	100%	100%	100%	37%	423,741	4,178	137,148
33%	100%	100%	100%	100%	33%	657,609	6,483	288,813
33%	100%	100%	100%	100%	33%	14,885	147	14,705
33%	100%	100%	100%	100%	33%	119,646	1,180	14,414
39%	100%	100%	100%	100%	39%	1,526,248	15,047	176,292
38%	100%	100%	100%	100%	38%	98,397	970	35,739
41%	100%	100%	100%	100%	41%	7,055	70	1,510
47%	100%	100%	100%	100%	47%	41,495	409	12,113
0%	100%	100%	100%	100%	0%	n/a	n/a	
52%	100%	100%	100%	100%	52%	903,439	8,907	246,496
45%	100%	100%	100%	100%	45%	128,609	1,268	58,804
0%	100%	100%	100%	100%	0%	28,376	280	-
0%	100%	100%	100%	100%	0%	457,649	4,512	-
0%	100%	100%	100%	100%	0%	14,029	138	-
47%	100%	100%	100%	100%	47%	842,772	8,309	147,838
0%	100%	100%	100%	100%	0%	110,248	1,087	-
35%	100%	100%	100%	100%	35%	263	3	454
42%	100%	100%	100%	100%	42%	295	3	172
44%	100%	100%	100%	100%	44%	7,897	78	17,122
44%	100%	100%	100%	100%	44%	8,535	84	5,209
48%	100%	100%	100%	100%	48%	6,808	67	8,866
90%	100%	100%	100%	100%	90%	28,831	405	6,306
90%	100%	100%	100%	100%	90%	14,152	119	1,853
90%	100%	100%	100%	100%	90%	318	0	-
90%	100%	100%	100%	100%	90%	104	30	1,998
90%	100%	100%	100%	100%	90%	47	18	1,199
90%	100%	100%	100%	100%	90%	1	0	-
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
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n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
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n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
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n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	

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n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

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n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
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n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	482,323
Custom	100%	100%	100%	100%	Custom	n/a	n/a	
Custom	100%	100%	100%	100%	Custom	n/a	n/a	
Custom	100%	100%	100%	100%	Custom	n/a	n/a	
Custom	100%	100%	100%	100%	Custom	n/a	n/a	2,966
93%	100%	100%	100%	100%	93%	18,026	0	
93%	100%	100%	100%	100%	93%	287	0	
93%	100%	100%	100%	100%	93%	3,256	0	
93%	100%	100%	100%	100%	93%	53	0	
93%	100%	100%	100%	100%	93%	35	0	
93%	100%	100%	100%	100%	93%	1	0	
93%	100%	100%	100%	100%	93%	0	0	
100%	100%	100%	100%	100%	100%	1,775	0	
70%	100%	100%	100%	100%	70%	1	0	
70%	100%	100%	100%	100%	70%	3	0	
70%	100%	100%	100%	100%	70%	1	0	
70%	100%	100%	100%	100%	70%	1	0	
70%	100%	100%	100%	100%	70%	0	0	
70%	100%	100%	100%	100%	70%	1	0	
70%	100%	100%	100%	100%	70%	1	0	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	n/a	n/a	
100%	100%	100%	100%	100%	100%	0	0	
100%	100%	100%	100%	100%	100%	7	0	
100%	100%	100%	100%	100%	100%	116	0	
100%	100%	100%	100%	100%	100%	2	0	
100%	100%	100%	100%	100%	100%	2	0	3,031,498

#	Local Distribution Company	2006 Residential Peak Load (kW)	2006 Residential Peak Load (%)	2006 Residential Energy Throughput (kWh)	2006 Residential Energy Throughput (%)	2006 Non-Residential Peak Load (kW)	2006 Non-Residential Peak Load (%)	2006 Non-Residential Energy Throughput (kWh)	2006 Non-Residential Energy Throughput (%)	2007 Residential Peak Load (kW)	2007 Residential Peak Load (%)
1	Atikokan Hydro Inc.	n/a	n/a	11,400,673	0.03%	n/a	n/a	34,099,588	0.04%	n/a	n/a
2	Attawapiskat First Nation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
3	Attawapiskat Power Corporation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
4	Barrie Hydro Distribution Inc.	n/a	n/a	530,557,254	1.32%	n/a	n/a	937,360,428	1.20%	n/a	n/a
5	Bluewater Power Distribution Corporation	n/a	n/a	261,470,152	0.65%	n/a	n/a	842,737,021	1.08%	n/a	n/a
6	Brant County Power Inc.	n/a	n/a	79,563,205	0.20%	n/a	n/a	145,133,733	0.19%	n/a	n/a
7	Brantford Power Inc.	n/a	n/a	284,501,278	0.71%	n/a	n/a	680,671,928	0.87%	n/a	n/a
8	Burlington Hydro Inc.	n/a	n/a	551,419,663	1.37%	n/a	n/a	1,182,280,000	1.51%	n/a	n/a
9	COLLUS Power Corp.	n/a	n/a	110,110,859	0.27%	n/a	n/a	225,767,061	0.29%	n/a	n/a
10	Cambridge and North Dumfries Hydro Inc.	n/a	n/a	389,897,758	0.97%	n/a	n/a	1,175,499,726	1.50%	n/a	n/a
11	Canadian Niagara Power Inc.	n/a	n/a	143,693,705	0.36%	n/a	n/a	215,257,881	0.27%	n/a	n/a
12	Centre Wellington Hydro Ltd.	n/a	n/a	44,421,203	0.11%	n/a	n/a	104,851,041	0.13%	n/a	n/a
13	Chapleau Public Utilities Corporation	n/a	n/a	14,654,854	0.04%	n/a	n/a	13,456,323	0.02%	n/a	n/a
14	Chatham-Kent Hydro Inc.	n/a	n/a	239,607,514	0.60%	n/a	n/a	615,842,408	0.79%	n/a	n/a
15	Clinton Power Corporation	n/a	n/a	12,656,005	0.03%	n/a	n/a	5,883,572	0.01%	n/a	n/a
16	Cooperative Hydro Embrun Inc.	n/a	n/a	19,799,972	0.05%	n/a	n/a	9,670,245	0.01%	n/a	n/a
17	Cornwall Street Railway Light and Power Company Limited	n/a	n/a		0.00%	n/a	n/a	3,316,831	0.00%	n/a	n/a
18	Dubreuil Forest Products Ltd.	n/a	n/a		0.00%	n/a	n/a	104,680,214	0.13%	n/a	n/a
19	Dutton Hydro Limited	n/a	n/a	409,958	0.00%	n/a	n/a	244,729,136	0.31%	n/a	n/a
20	E.L.K. Energy Inc.	n/a	n/a	91,182,112	0.23%	n/a	n/a	45,502,520	0.06%	n/a	n/a
21	ENWIN Utilities Ltd.	n/a	n/a	655,143,475	1.63%	n/a	n/a	244,729,136	0.31%	n/a	n/a
22	Enersource Hydro Mississauga Inc.	n/a	n/a	1,603,332,097	3.98%	n/a	n/a	6,490,116,773	8.28%	n/a	n/a
23	Erie Thames Powerlines Corporation	n/a	n/a	116,103,693	0.29%	n/a	n/a	36,572,686	0.05%	n/a	n/a
24	Espanola Regional Hydro Distribution Corporation	n/a	n/a	32,486,898	0.08%	n/a	n/a	30,450,548	0.04%	n/a	n/a
25	Essex Powerlines Corporation	n/a	n/a	284,492,550	0.71%	n/a	n/a	148,696,240	0.19%	n/a	n/a
26	Festival Hydro Inc.	n/a	n/a	142,060,467	0.35%	n/a	n/a	471,908,335	0.60%	n/a	n/a
27	Fort Albany First Nation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
28	Fort Albany Power Corporation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
29	Fort Frances Power Corporation	n/a	n/a	38,401,315	0.10%	n/a	n/a	42,879,081	0.05%	n/a	n/a
30	Grand Valley Energy Inc	n/a	n/a	5,683,369	0.01%	n/a	n/a	2,812,411	0.00%	n/a	n/a
31	Great Lakes Power Limited	n/a	n/a	91,383,636	0.23%	n/a	n/a	102,068,591	0.13%	n/a	n/a
32	Greater Sudbury Hydro Inc.	n/a	n/a	397,678,409	0.99%	n/a	n/a	535,059,474	0.68%	n/a	n/a
33	Grimsby Power Incorporated	n/a	n/a	85,590,583	0.21%	n/a	n/a	18,314,103	0.02%	n/a	n/a
34	Guelph Hydro Electric Systems Inc.	n/a	n/a	357,495,622	0.89%	n/a	n/a	1,264,636,266	1.61%	n/a	n/a
35	Haldimand County Hydro Inc.	n/a	n/a	172,359,424	0.43%	n/a	n/a	185,282,283	0.24%	n/a	n/a
36	Halton Hills Hydro Inc.	n/a	n/a	200,925,506	0.50%	n/a	n/a	271,457,391	0.35%	n/a	n/a
37	Hearst Power Distribution Company Limited	n/a	n/a	26,681,677	0.07%	n/a	n/a	87,318,533	0.11%	n/a	n/a
38	Horizon Utilities Corporation	n/a	n/a	1,654,664,050	4.11%	n/a	n/a	3,638,046,674	4.64%	n/a	n/a
39	Hydro 2000 Inc.	n/a	n/a	15,223,723	0.04%	n/a	n/a	10,268,966	0.01%	n/a	n/a
40	Hydro Hawkesbury Inc.	n/a	n/a	54,802,923	0.14%	n/a	n/a	143,819,890	0.18%	n/a	n/a
41	Hydro One Brampton Networks Inc.	n/a	n/a	1,075,118,931	2.67%	n/a	n/a	2,744,176,570	3.50%	n/a	n/a
42	Hydro One Networks Inc.	n/a	n/a	12,237,925,130	30.40%	n/a	n/a	9,935,112,037	12.68%	n/a	n/a
43	Hydro One Networks Inc./Cat Lake Power Community	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
44	Hydro One Remote Communities Inc.	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
45	Hydro Ottawa Limited	n/a	n/a	2,226,415,669	5.53%	n/a	n/a	5,188,092,986	6.62%	n/a	n/a
46	Innisfil Hydro Distribution Systems Limited	n/a	n/a	157,140,654	0.39%	n/a	n/a	28,964,493	0.04%	n/a	n/a
47	Kashechewan First Nation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
48	Kashechewan Power Corporation	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
49	Kenora Hydro Electric Corporation Ltd.	n/a	n/a	39,159,513	0.10%	n/a	n/a	68,402,801	0.09%	n/a	n/a
50	Kingston Hydro Corporation	n/a	n/a	200,214,258	0.50%	n/a	n/a	531,028,042	0.68%	n/a	n/a
51	Kitchener-Wilmot Hydro Inc.	n/a	n/a	644,108,007	1.60%	n/a	n/a	1,309,299,590	1.67%	n/a	n/a
52	Lakefront Utilities Inc.	n/a	n/a	67,942,208	0.17%	n/a	n/a	213,381,240	0.27%	n/a	n/a
53	Lakeland Power Distribution Ltd.	n/a	n/a	78,930,880	0.20%	n/a	n/a	45,933,794	0.06%	n/a	n/a

54	London Hydro Inc.	n/a	n/a	1,088,755,114	2.70%	n/a	n/a	2,244,907,930	2.87%	n/a	n/a
55	Middlesex Power Distribution Corporation	n/a	n/a	57,128,547	0.14%	n/a	n/a	145,163,360	0.19%	n/a	n/a
56	Midland Power Utility Corporation	n/a	n/a	43,734,088	0.11%	n/a	n/a	177,618,443	0.23%	n/a	n/a
57	Milton Hydro Distribution Inc.	n/a	n/a	197,466,598	0.49%	n/a	n/a	439,013,389	0.56%	n/a	n/a
58	Newbury Power Inc.	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
59	Newmarket - Tay Power Distribution Ltd.	n/a	n/a	262,995,579	0.65%	n/a	n/a	93,266,581	0.12%	n/a	n/a
60	Niagara Peninsula Energy Inc.	n/a	n/a	449,386,643	1.12%	n/a	n/a	809,188,538	1.03%	n/a	n/a
61	Niagara-on-the-Lake Hydro Inc.	n/a	n/a	63,805,148	0.16%	n/a	n/a	111,101,732	0.14%	n/a	n/a
62	Norfolk Power Distribution Inc.	n/a	n/a	139,960,236	0.35%	n/a	n/a	237,962,119	0.30%	n/a	n/a
63	North Bay Hydro Distribution Limited	n/a	n/a	207,199,584	0.51%	n/a	n/a	349,174,613	0.45%	n/a	n/a
64	Northern Ontario Wires Inc.	n/a	n/a	43,040,214	0.11%	n/a	n/a	91,314,990	0.12%	n/a	n/a
65	Oakville Hydro Electricity Distribution Inc.	n/a	n/a	569,566,301	1.41%	n/a	n/a	994,238,859	1.27%	n/a	n/a
66	Orangeville Hydro Limited	n/a	n/a	79,376,454	0.20%	n/a	n/a	160,927,606	0.21%	n/a	n/a
67	Orillia Power Distribution Corporation	n/a	n/a	108,206,276	0.27%	n/a	n/a	209,218,547	0.27%	n/a	n/a
68	Oshawa PUC Networks Inc.	n/a	n/a	465,431,095	1.16%	n/a	n/a	632,361,055	0.81%	n/a	n/a
69	Ottawa River Power Corporation	n/a	n/a	75,536,829	0.19%	n/a	n/a	116,088,912	0.15%	n/a	n/a
70	PUC Distribution Inc.	n/a	n/a	335,395,539	0.83%	n/a	n/a	353,865,433	0.45%	n/a	n/a
71	Parry Sound Power Corporation	n/a	n/a	33,103,725	0.08%	n/a	n/a	51,649,272	0.07%	n/a	n/a
72	Peterborough Distribution Incorporated	n/a	n/a	290,645,501	0.72%	n/a	n/a	512,167,589	0.65%	n/a	n/a
73	Port Colborne Hydro Inc.	n/a	n/a	63,748,755	0.16%	n/a	n/a	131,007,820	0.17%	n/a	n/a
74	PowerStream Inc.	n/a	n/a	2,003,371,840	4.98%	n/a	n/a	4,700,083,921	6.00%	n/a	n/a
75	Renfrew Hydro Inc.	n/a	n/a	30,640,237	0.08%	n/a	n/a	65,574,034	0.08%	n/a	n/a
76	Rideau St. Lawrence Distribution Inc.	n/a	n/a	44,343,815	0.11%	n/a	n/a	22,573,648	0.03%	n/a	n/a
77	Sioux Lookout Hydro Inc.	n/a	n/a	31,452,628	0.08%	n/a	n/a	60,136,389	0.08%	n/a	n/a
78	St. Thomas Energy Inc.	n/a	n/a	113,523,979	0.28%	n/a	n/a	250,600,744	0.32%	n/a	n/a
79	Thunder Bay Hydro Electricity Distribution Inc.	n/a	n/a	346,415,246	0.86%	n/a	n/a	681,186,819	0.87%	n/a	n/a
80	Tillsonburg Hydro Inc.	n/a	n/a	52,306,081	0.13%	n/a	n/a	175,367,100	0.22%	n/a	n/a
81	Toronto Hydro-Electric System Limited	n/a	n/a	5,351,746,739	13.29%	n/a	n/a	20,069,911,519	25.61%	n/a	n/a
82	Veridian Connections Inc.	n/a	n/a	929,432,918	2.31%	n/a	n/a	1,583,103,519	2.02%	n/a	n/a
83	Wasaga Distribution Inc.	n/a	n/a	73,495,682	0.18%	n/a	n/a	31,661,531	0.04%	n/a	n/a
84	Waterloo North Hydro Inc.	n/a	n/a	391,947,018	0.97%	n/a	n/a	922,560,313	1.18%	n/a	n/a
85	Welland Hydro-Electric System Corp.	n/a	n/a	169,952,289	0.42%	n/a	n/a	314,737,340	0.40%	n/a	n/a
86	Wellington North Power Inc.	n/a	n/a	25,536,958	0.06%	n/a	n/a	68,059,736	0.09%	n/a	n/a
87	West Coast Huron Energy Inc.	n/a	n/a	27,222,139	0.07%	n/a	n/a	119,067,345	0.15%	n/a	n/a
88	West Perth Power Inc.	n/a	n/a		0.00%	n/a	n/a		0.00%	n/a	n/a
89	Westario Power Inc.	n/a	n/a	207,243,931	0.51%	n/a	n/a	243,567,288	0.31%	n/a	n/a
90	Whitby Hydro Electric Corporation	n/a	n/a	337,897,948	0.84%	n/a	n/a	511,216,232	0.65%	n/a	n/a
91	Woodstock Hydro Services Inc.	n/a	n/a	104,833,112	0.26%	n/a	n/a	300,154,329	0.38%	n/a	n/a
Total		**n/a**	**n/a**	**40,262,655,618**	**100.00%**	**n/a**	**n/a**	**78,355,367,185**	**100.00%**	**n/a**	**n/a**

2007 Residential Energy Throughput (kWh)	2007 Residential Energy Throughput (%)	2007 Non-Residential Peak Load (kW)	2007 Non-Residential Peak Load (%)	2007 Non-Residential Energy Throughput (kWh)	2007 Non-Residential Energy Throughput (%)	2008 Residential Peak Load (kW)	2008 Residential Peak Load (%)	2008 Residential Energy Throughput (kWh)	2008 Residential Energy Throughput (%)	2008 Non-Residential Peak Load (kW)	2008 Non-Residential Peak Load (%)	2008 Non-Residential Energy Throughput (kWh)	2008 Non-Residential Energy Throughput (%)
11,858,778	0.03%	n/a	n/a	31,082,191	0.04%	n/a	n/a	11,183,350	0.03%	n/a	n/a	14,843,605	0.02%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
548,016,272	1.33%	n/a	n/a	940,740,837	1.14%	n/a	n/a	547,117,234	1.35%	n/a	n/a	980,805,847	1.21%
264,836,003	0.64%	n/a	n/a	855,922,144	1.04%	n/a	n/a	261,354,534	0.64%	n/a	n/a	821,568,128	1.02%
81,004,255	0.20%	n/a	n/a	207,717,221	0.25%	n/a	n/a	79,817,804	0.20%	n/a	n/a	200,988,235	0.25%
298,531,289	0.73%	n/a	n/a	741,598,484	0.90%	n/a	n/a	291,972,257	0.72%	n/a	n/a	719,465,778	0.89%
567,063,035	1.38%	n/a	n/a	1,199,736,238	1.45%	n/a	n/a	557,752,794	1.37%	n/a	n/a	1,158,340,390	1.43%
113,589,579	0.28%	n/a	n/a	215,072,148	0.26%	n/a	n/a	114,695,863	0.28%	n/a	n/a	205,759,520	0.25%
395,062,443	0.96%	n/a	n/a	1,165,105,313	1.41%	n/a	n/a	384,779,246	0.95%	n/a	n/a	1,125,532,050	1.39%
143,862,348	0.35%	n/a	n/a	215,810,521	0.26%	n/a	n/a	141,136,541	0.35%	n/a	n/a	206,108,617	0.25%
46,699,194	0.11%	n/a	n/a	111,831,932	0.14%	n/a	n/a	44,627,090	0.11%	n/a	n/a	113,895,413	0.14%
15,018,918	0.04%	n/a	n/a	13,186,691	0.02%	n/a	n/a	15,056,281	0.04%	n/a	n/a	13,204,594	0.02%
236,072,777	0.57%	n/a	n/a	601,416,856	0.73%	n/a	n/a	232,973,162	0.57%	n/a	n/a	578,228,629	0.71%
12,522,951	0.03%	n/a	n/a	18,085,796	0.02%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
19,386,628	0.05%	n/a	n/a	9,298,043	0.01%	n/a	n/a	19,644,024	0.05%	n/a	n/a	9,451,266	0.01%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
94,171,770	0.23%	n/a	n/a	160,761,797	0.19%	n/a	n/a	93,091,229	0.23%	n/a	n/a	157,019,403	0.19%
664,998,752	1.62%	n/a	n/a	1,903,884,798	2.31%	n/a	n/a	637,053,725	1.57%	n/a	n/a	1,801,822,532	2.23%
1,632,816,129	3.97%	n/a	n/a	6,605,288,225	8.00%	n/a	n/a	1,590,715,870	3.92%	n/a	n/a	6,464,408,854	7.99%
116,256,740	0.28%	n/a	n/a	291,852,488	0.35%	n/a	n/a	115,637,295	0.28%	n/a	n/a	278,295,099	0.34%
32,040,530	0.08%	n/a	n/a	31,021,479	0.04%	n/a	n/a	32,354,293	0.08%	n/a	n/a	30,605,267	0.04%
280,966,066	0.68%	n/a	n/a	279,180,331	0.34%	n/a	n/a	261,929,749	0.65%	n/a	n/a	278,831,202	0.34%
143,658,315	0.35%	n/a	n/a	468,128,577	0.57%	n/a	n/a	140,987,205	0.35%	n/a	n/a	448,339,012	0.55%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
39,011,690	0.09%	n/a	n/a	43,615,480	0.05%	n/a	n/a	39,844,007	0.10%	n/a	n/a	42,938,079	0.05%
5,786,652	0.01%	n/a	n/a	3,568,735	0.00%	n/a	n/a	5,882,230	0.01%	n/a	n/a	3,097,510	0.00%
92,360,867	0.22%	n/a	n/a	109,854,997	0.13%	n/a	n/a	87,951,272	0.22%	n/a	n/a	89,322,297	0.11%
405,736,204	0.99%	n/a	n/a	543,747,565	0.66%	n/a	n/a	411,072,289	1.01%	n/a	n/a	546,788,157	0.68%
86,770,666	0.21%	n/a	n/a	88,449,813	0.11%	n/a	n/a	91,344,616	0.23%	n/a	n/a	87,677,058	0.11%
358,331,164	0.87%	n/a	n/a	1,269,317,570	1.54%	n/a	n/a	366,970,148	0.90%	n/a	n/a	1,223,442,614	1.51%
173,795,327	0.42%	n/a	n/a	183,754,191	0.22%	n/a	n/a	171,781,095	0.42%	n/a	n/a	177,498,802	0.22%
208,287,499	0.51%	n/a	n/a	311,739,725	0.38%	n/a	n/a	220,683,563	0.54%	n/a	n/a	276,894,738	0.34%
28,317,089	0.07%	n/a	n/a	82,118,980	0.10%	n/a	n/a	26,743,823	0.07%	n/a	n/a	56,718,432	0.07%
1,666,789,557	4.06%	n/a	n/a	4,575,455,672	5.54%	n/a	n/a	1,641,702,487	4.04%	n/a	n/a	4,317,582,512	5.34%
15,036,848	0.04%	n/a	n/a	9,877,930	0.01%	n/a	n/a	15,306,507	0.04%	n/a	n/a	10,138,585	0.01%
56,403,314	0.14%	n/a	n/a	145,226,883	0.18%	n/a	n/a	55,769,040	0.14%	n/a	n/a	138,066,467	0.17%
1,141,600,000	2.78%	n/a	n/a	2,798,700,000	3.39%	n/a	n/a	1,136,600,000	2.80%	n/a	n/a	2,748,900,000	3.40%
12,620,681,000	30.71%	n/a	n/a	10,298,799,000	12.47%	n/a	n/a	12,410,000,000	30.57%	n/a	n/a	9,990,000,000	12.35%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
2,234,039,085	5.44%	n/a	n/a	5,255,181,082	6.36%	n/a	n/a	2,226,078,653	5.48%	n/a	n/a	5,274,086,924	6.52%
156,705,342	0.38%	n/a	n/a	71,986,330	0.09%	n/a	n/a	158,043,498	0.39%	n/a	n/a	78,175,459	0.10%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a		0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
39,142,088	0.10%	n/a	n/a	70,186,402	0.08%	n/a	n/a	39,338,336	0.10%	n/a	n/a	69,225,456	0.09%
221,960,966	0.54%	n/a	n/a	497,012,043	0.60%	n/a	n/a	200,853,045	0.49%	n/a	n/a	535,320,723	0.66%
660,550,766	1.61%	n/a	n/a	1,312,172,498	1.59%	n/a	n/a	659,163,062	1.62%	n/a	n/a	1,257,832,920	1.56%
74,685,958	0.18%	n/a	n/a	215,906,659	0.26%	n/a	n/a	75,604,253	0.19%	n/a	n/a	205,196,563	0.25%
78,209,625	0.19%	n/a	n/a	135,514,735	0.16%	n/a	n/a	81,234,268	0.20%	n/a	n/a	136,289,494	0.17%

1,117,283,048	2.72%	n/a	n/a	2,246,550,773	2.72%	n/a	n/a	1,119,770,671	2.76%	n/a	n/a	2,189,969,229	2.71%
57,541,659	0.14%	n/a	n/a	139,592,176	0.17%	n/a	n/a	57,013,718	0.14%	n/a	n/a	132,646,565	0.16%
47,886,438	0.12%	n/a	n/a	175,517,601	0.21%	n/a	n/a	48,136,133	0.12%	n/a	n/a	166,162,739	0.21%
218,633,202	0.53%	n/a	n/a	470,712,726	0.57%	n/a	n/a	225,897,498	0.56%	n/a	n/a	476,230,193	0.59%
463,355	0.00%	n/a	n/a	606,285	0.00%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
270,904,453	0.66%	n/a	n/a	96,866,788	0.12%	n/a	n/a	268,062,456	0.66%	n/a	n/a	452,921,581	0.56%
423,910,347	1.03%	n/a	n/a	853,493,894	1.03%	n/a	n/a	400,445,564	0.99%	n/a	n/a	813,890,886	1.01%
65,561,722	0.16%	n/a	n/a	112,958,244	0.14%	n/a	n/a	63,512,671	0.16%	n/a	n/a	109,639,488	0.14%
142,543,771	0.35%	n/a	n/a	236,960,151	0.29%	n/a	n/a	140,646,761	0.35%	n/a	n/a	230,446,897	0.28%
213,131,701	0.52%	n/a	n/a	353,433,822	0.43%	n/a	n/a	213,813,392	0.53%	n/a	n/a	349,313,014	0.43%
43,226,412	0.11%	n/a	n/a	87,800,701	0.11%	n/a	n/a	41,990,761	0.10%	n/a	n/a	78,987,933	0.10%
592,214,968	1.44%	n/a	n/a	1,015,760,199	1.23%	n/a	n/a	588,349,444	1.45%	n/a	n/a	991,360,456	1.23%
80,135,717	0.19%	n/a	n/a	165,400,748	0.20%	n/a	n/a	79,576,857	0.20%	n/a	n/a	159,288,984	0.20%
109,590,116	0.27%	n/a	n/a	208,616,563	0.25%	n/a	n/a	109,814,584	0.27%	n/a	n/a	206,291,735	0.26%
495,109,283	1.20%	n/a	n/a	685,818,845	0.83%	n/a	n/a	493,225,543	1.22%	n/a	n/a	661,990,009	0.82%
75,938,194	0.18%	n/a	n/a	84,784,890	0.10%	n/a	n/a	78,434,655	0.19%	n/a	n/a	114,881,644	0.14%
338,874,337	0.82%	n/a	n/a	355,019,853	0.43%	n/a	n/a	347,363,230	0.86%	n/a	n/a	355,446,428	0.44%
34,279,947	0.08%	n/a	n/a	54,561,642	0.07%	n/a	n/a	34,188,975	0.08%	n/a	n/a	53,124,268	0.07%
286,683,602	0.70%	n/a	n/a	525,620,624	0.64%	n/a	n/a	288,028,301	0.71%	n/a	n/a	525,236,456	0.65%
65,276,304	0.16%	n/a	n/a	125,625,452	0.15%	n/a	n/a	64,024,829	0.16%	n/a	n/a	127,071,772	0.16%
2,039,498,572	4.96%	n/a	n/a	4,749,900,082	5.75%	n/a	n/a	2,077,903,209	5.12%	n/a	n/a	4,705,762,883	5.82%
31,007,901	0.08%	n/a	n/a	67,121,871	0.08%	n/a	n/a	31,465,398	0.08%	n/a	n/a	69,352,093	0.09%
45,086,486	0.11%	n/a	n/a	67,416,920	0.08%	n/a	n/a	44,465,236	0.11%	n/a	n/a	65,825,492	0.08%
32,814,076	0.08%	n/a	n/a	57,375,461	0.07%	n/a	n/a	33,587,664	0.08%	n/a	n/a	42,670,262	0.05%
119,400,889	0.29%	n/a	n/a	244,392,868	0.30%	n/a	n/a	120,297,987	0.30%	n/a	n/a	220,058,899	0.27%
344,508,404	0.84%	n/a	n/a	669,420,045	0.81%	n/a	n/a	351,645,318	0.87%	n/a	n/a	644,339,043	0.80%
52,893,412	0.13%	n/a	n/a	183,570,981	0.22%	n/a	n/a	51,050,818	0.13%	n/a	n/a	165,205,863	0.20%
5,332,356,184	12.97%	n/a	n/a	20,316,766,672	24.60%	n/a	n/a	5,215,687,193	12.85%	n/a	n/a	19,811,187,290	24.50%
960,984,164	2.34%	n/a	n/a	1,566,734,483	1.90%	n/a	n/a	942,451,035	2.32%	n/a	n/a	1,538,562,235	1.90%
78,007,343	0.19%	n/a	n/a	35,464,935	0.04%	n/a	n/a	76,997,980	0.19%	n/a	n/a	37,455,844	0.05%
405,071,611	0.99%	n/a	n/a	954,721,743	1.16%	n/a	n/a	405,533,476	1.00%	n/a	n/a	956,629,104	1.18%
162,857,785	0.40%	n/a	n/a	300,569,977	0.36%	n/a	n/a	157,955,849	0.39%	n/a	n/a	304,094,821	0.38%
25,027,983	0.06%	n/a	n/a	69,405,347	0.08%	n/a	n/a	25,485,646	0.06%	n/a	n/a	67,434,118	0.08%
26,672,783	0.06%	n/a	n/a	117,989,487	0.14%	n/a	n/a	26,528,425	0.07%	n/a	n/a	126,738,954	0.16%
15,466,784	0.04%	n/a	n/a	46,047,710	0.06%	n/a	n/a	0	0.00%	n/a	n/a	0	0.00%
213,039,032	0.52%	n/a	n/a	246,987,034	0.30%	n/a	n/a	213,227,356	0.53%	n/a	n/a	254,222,507	0.31%
347,926,496	0.85%	n/a	n/a	511,966,838	0.62%	n/a	n/a	346,038,642	0.85%	n/a	n/a	500,707,723	0.62%
104,412,330	0.25%	n/a	n/a	287,974,277	0.35%	n/a	n/a	110,536,185	0.27%	n/a	n/a	295,103,216	0.36%
41,098,855,290	**100.00%**	**n/a**	**n/a**	**82,578,437,108**	**100.00%**	**n/a**	**n/a**	**40,588,999,198**	**100.00%**	**n/a**	**n/a**	**80,872,956,854**	**100.00%**