File Number: EB-2014-0096

Date Filed: September 23, 2014

Exhibit 2

RATE BASE

Exhibit 2

Tab 1 of 3

Rate Base

Overview

This exhibit provides NPEI's distribution rate base forecast for the 2015 Test Year. It also provides an explanation of variances between 2011 Board approved figures, 2011 through 2013 actuals, 2014 Bridge Year and the 2015 Test Year.

NPEI is seeking approval in this Application for 2015 electricity distribution rates effective May 1, 2015. In accordance with the Board's Filing Requirements, the rate base used to determine the Test Year revenue requirement includes the average of the opening and closing balances for net capital assets plus a working capital allowance. Net capital assets are gross assets in service minus accumulated depreciation and contributed capital from third parties. The working capital allowance is 13% of the sum of cost of power plus controllable expenses.

Capital assets include property, plant and equipment and intangible assets that enable the conveyance of electricity for distribution purposes. The NPEI rate base calculation excludes any non-distribution assets, with the exception of the Kalar Transformer Station, which Niagara Falls Hydro put into service in 2004. The Kalar TS assets were approved by the Board in Niagara Falls Hydro's 2006 EDR Application (EB-2005-0394) to be deemed distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Table 2-1 below summarizes NPEI's rate base calculation for the years 2011 Board Approved, 2011 Actual to 2013 Actual, the 2014 Bridge Year and the 2015 Test Year.

Table 2-1: Summary of Rate Base

Description	2010 Actual	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Gross Fixed Assets	199,799,030	209,143,663	205,934,427	215,869,067	227,308,720	242,097,159	253,282,427
Accumulated Depreciation	(99,765,867)	(106,916,695)	(104,809,919)	(111,886,125)	(115,799,422)	(121,477,482)	(126,414,361)
Net Book Value	100,033,164	102,226,968	101,124,508	103,982,941	111,509,298	120,619,677	126,868,066
Average Net Book Value		101,130,066	100,578,836	102,553,725	107,746,120	116,064,488	123,743,871
Working Capital		122,917,489	128,749,974	136,002,927	144,712,291	152,230,470	153,984,823
Working Capital Allowance %		15%	15%	15%	15%	15%	13%
Working Capital Allowance		18,437,623	19,312,496	20,400,439	21,706,844	22,834,570	20,018,027
Rate Base		119,567,689	119,891,332	122,954,164	129,452,963	138,899,058	143,761,898

NPEI has calculated its 2015 Rate Base as $143,791,898.

The proposed Rate Base consists of a net average of $123.7M in Property, Plant and Equipment and $20.0M of Working Capital Allowance. The 2015 test year rate base is $24.2M greater than the 2011 Board Approved Rate Base. This increase in Rate Base is due to the following factors:

- increasing net book value of capital assets due to continued investment relied on to support the distribution system;
- the transfer of Smart Meter capital costs into Rate Base during 2014, in accordance with the Decision in NPEI's Smart Meter Application (EB-2013-0359);
- an increase in cost of power partially offset by a decrease in Working Capital Allowance percentage, and
- an increase in OM&A expenses.

NPEI has completed the Board's Appendix 2-BA, which is included at Exhibit 2, Tab 1, Schedule 1, Attachment 1.

Attachment 1 of 1

OEB Appendix 2-BA1/BA2

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year **2011**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,170,029	$ 247,505	-$ 54,000	$ 2,363,534	(1,945,983)	(104,805)		-$ 2,050,788	$ 312,745
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	0			$ -	$ 507,273
47	1806	Land Rights	$ 1,598,171			$ 1,598,171	(690,185)	(56,850)		-$ 747,035	$ 851,135
47	1808	Buildings	$ 111,638			$ 111,638	(99,967)	(4,111)		-$ 104,078	$ 7,560
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,602,001			$ 6,602,001	(903,106)	(146,009)		-$ 1,049,115	$ 5,552,885
47	1820	Distribution Station Equipment <50 kV	$ 4,984,096	$ 799,780		$ 5,783,876	(2,945,129)	(158,386)		-$ 3,103,515	$ 2,680,360
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 30,625,639	$ 1,760,405	-$ 0	$ 32,386,043	(16,981,049)	(886,143)	0	-$ 17,867,193	$ 14,518,851
47	1835	Overhead Conductors & Devices	$ 32,902,160	$ 1,721,225	-$ 0	$ 34,623,385	(14,955,471)	(1,228,547)	0	-$ 16,184,019	$ 18,439,366
47	1840	Underground Conduit	$ 11,491,536	$ 470,858	$ 0	$ 11,962,395	(785,673)	(203,336)	0	-$ 989,009	$ 10,973,386
47	1845	Underground Conductors & Devices	$ 56,340,588	$ 2,311,906	$ 0	$ 58,652,495	(33,154,619)	(2,365,136)	0	-$ 35,519,755	$ 23,132,740
47	1850	Line Transformers	$ 32,027,302	$ 1,064,335	-$ 209,294	$ 32,882,342	(17,051,222)	(1,130,747)	209,294	-$ 17,972,675	$ 14,909,667
47	1855	Services (Overhead & Underground)	$ 3,853,918	$ 338,070	$ 0	$ 4,191,989	(772,447)	(160,916)	0	-$ 933,363	$ 3,258,626
47	1860	Meters	$ 2,493,234	$ 177,180	-$ 92,783	$ 2,577,631	(1,031,412)	(419,378)	173,002	-$ 1,277,788	$ 1,299,844
47	1860	Meters (Smart Meters)	$ 4,175,010			$ 4,175,010	0	0	0	$ -	$ 4,175,010
47	1865	Other Installations on Customer's Premises	$ -			$ -				$ -	$ -
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	(4,119)	(841)		-$ 4,960	$ 16,875
N/A	1905	Land	$ 508,970			$ 508,970				$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 12,458,371	$ 121,779		$ 12,580,150	(2,026,855)	(211,195)		-$ 2,238,051	$ 10,342,100
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	(120,252)	0		-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,142,390	$ 68,799		$ 1,211,189	(700,466)	(73,244)		-$ 773,710	$ 437,479
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	(1,257,769)	0		-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	(315,054)			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,304,708	$ 247,812		$ 1,552,520	(611,848)	(232,399)		-$ 844,247	$ 708,272
10	1930	Transportation Equipment	$ 6,353,935	$ 541,641	-$ 451,092	$ 6,444,484	(4,104,214)	(438,087)	434,695	-$ 4,107,605	$ 2,336,879
8	1935	Stores Equipment	$ 226,597	$ 9,817		$ 236,414	(186,481)	(4,736)		-$ 191,217	$ 45,197
8	1940	Tools, Shop & Garage Equipment	$ 1,661,083	$ 77,760		$ 1,738,843	(1,320,132)	(66,153)		-$ 1,386,285	$ 352,558
8	1945	Measurement & Testing Equipment	$ 188,846	$ 15,160		$ 204,006	(161,507)	(17,292)		-$ 178,798	$ 25,208
8	1950	Power Operated Equipment	$ -			$ -	0	0		$ -	$ -
8	1955	Communications Equipment	$ 168,596	$ 1,985		$ 170,581	(112,449)	(21,204)		-$ 133,653	$ 36,928
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	(53,367)	(6,973)		-$ 60,340	$ 12,612
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	(128,961)	0		-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 17,481,077	-$ 1,571,526		-$ 19,052,603	4,023,356	705,962		$ 4,729,318	-$ 14,323,285
47	2440	Deferred Revenue[5]				$ -					$ -
47	2005	2005-Property Under Capital Leases				$ -					
						$ -				$ -	$ -
		Sub-Total	**$ 198,337,106**	**$ 8,404,491**	**-$ 807,169**	**$ 205,934,428**	**(98,396,385)**	**-$ 7,230,525**	**$ 816,991**	**-$ 104,809,919**	**$ 101,124,509**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 198,337,106**	**$ 8,404,491**	**-$ 807,169**	**$ 205,934,428**	**(98,396,385)**	**-$ 7,230,525**	**$ 816,991**	**-$ 104,809,919**	**$ 101,124,509**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 7,230,525**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 7,230,525

Notes:

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

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

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

4. The additions column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year **2012**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,363,534	$ 213,431		$ 2,576,965	-$ 2,050,788	-$ 159,612		-$ 2,210,400	$ 366,564
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,598,171	$ 5,416		$ 1,603,587	-$ 747,035	-$ 64,029		-$ 811,064	$ 792,523
47	1808	Buildings	$ 111,638			$ 111,638	-$ 104,078	-$ 7,559		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,602,001	$ 16,266		$ 6,618,267	-$ 1,049,115	-$ 146,212		-$ 1,195,327	$ 5,422,939
47	1820	Distribution Station Equipment <50 kV	$ 5,783,876	$ 666,649		$ 6,450,525	-$ 3,103,515	-$ 191,905		-$ 3,295,420	$ 3,155,105
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 32,386,043	$ 1,474,815	$ -	$ 33,860,858	-$ 17,867,193	-$ 945,170	$ -	-$ 18,812,363	$ 15,048,495
47	1835	Overhead Conductors & Devices	$ 34,623,385	$ 1,638,693	$ -	$ 36,262,078	-$ 16,184,019	-$ 1,299,638	$ -	-$ 17,483,657	$ 18,778,421
47	1840	Underground Conduit	$ 11,962,395	$ 802,096	$ -	$ 12,764,491	-$ 989,009	-$ 228,692	$ -	-$ 1,217,701	$ 11,546,789
47	1845	Underground Conductors & Devices	$ 58,652,495	$ 2,345,741	$ -	$ 60,998,236	-$ 35,519,755	-$ 2,266,640	$ -	-$ 37,786,395	$ 23,211,841
47	1850	Line Transformers	$ 32,882,342	$ 1,246,688	-$ 241,410	$ 33,887,620	-$ 17,972,675	-$ 1,204,681	$ 241,410	-$ 18,935,946	$ 14,951,674
47	1855	Services (Overhead & Underground)	$ 4,191,989	$ 437,074	$ 0	$ 4,629,063	-$ 933,363	-$ 176,420	$ -	-$ 1,109,783	$ 3,519,280
47	1860	Meters	$ 2,577,631	$ 209,382	-$ 141,557	$ 2,645,456	-$ 1,277,788	-$ 362,629	$ 103,655	-$ 1,536,762	$ 1,108,694
47	1860	Meters (Smart Meters)	$ 4,175,010			$ 4,175,010	$ -	$ -		$ -	$ 4,175,010
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -			$ -	$ -
47	1875	Street Lighting and Signal Systems	$ 21,835			$ 21,835	-$ 4,960	-$ 1,313		-$ 6,273	$ 15,562
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 12,580,150	$ 625,695		$ 13,205,846	-$ 2,238,051	-$ 217,483		-$ 2,455,533	$ 10,750,312
13	1910	Leasehold Improvements	$ 120,252	$ -		$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,211,189	$ 111,949		$ 1,323,138	-$ 773,710	-$ 78,052		-$ 851,763	$ 471,376
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,552,520	$ 370,710		$ 1,923,230	-$ 844,247	-$ 266,599		-$ 1,110,846	$ 812,383
10	1930	Transportation Equipment	$ 6,444,484	$ 1,160,649		$ 7,605,133	-$ 4,107,605	-$ 455,441		-$ 4,563,046	$ 3,042,087
8	1935	Stores Equipment	$ 236,414	$ -		$ 236,414	-$ 191,217	-$ 5,424		-$ 196,641	$ 39,773
8	1940	Tools, Shop & Garage Equipment	$ 1,738,843	$ 132,901		$ 1,871,744	-$ 1,386,285	-$ 70,945		-$ 1,457,230	$ 414,513
8	1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006	-$ 178,798	-$ 7,821		-$ 186,619	$ 17,387
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 170,581	$ 332,339		$ 502,920	-$ 133,653	-$ 22,328		-$ 155,981	$ 346,939
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 60,340	-$ 6,974		-$ 67,314	$ 5,637
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961	$ -		-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 19,052,603	-$ 1,472,887		-$ 20,525,490	$ 4,729,318	$ 764,297		$ 5,493,615	-$ 15,031,875
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				
						$ -				$ -	$ -
		Sub-Total	**$ 205,934,428**	**$ 10,317,607**	**-$ 382,967**	**$ 215,869,069**	**-$ 104,809,919**	**-$ 7,421,271**	**$ 345,065**	**-$ 111,886,125**	**$ 103,982,943**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 205,934,428**	**$ 10,317,607**	**-$ 382,967**	**$ 215,869,069**	**-$ 104,809,919**	**-$ 7,421,271**	**$ 345,065**	**-$ 111,886,125**	**$ 103,982,943**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 7,421,271**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 7,421,271

Notes:

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

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

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

4 The additions column (E) must not include construction work in progress (CWIP).

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Schedule:	1
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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year **2013**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Componentization**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,576,965			$ 2,576,965	-$ 2,210,400			-$ 2,210,400	$ 366,564
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,603,587			$ 1,603,587	-$ 811,064			-$ 811,064	$ 792,523
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637			-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 6,618,267	-$ 2,785,254		$ 3,833,013	-$ 1,195,327	$ 570,654		-$ 624,673	$ 3,208,339
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ -	$ 1,502,385.84		$ 1,502,386	$ -	-$ 176,327		-$ 176,327	$ 1,326,059
47	1815	Transformer Station Equipment > 50 kV (1716)	$ -	$ 46,955.06		$ 46,955	$ -	-$ 14,433		-$ 14,433	$ 32,522
47	1815	Transformer Station Equipment > 50 kV (1717)	$ -	$ 610,733.93		$ 610,734	$ -	-$ 187,727		-$ 187,727	$ 423,007
47	1815	Transformer Station Equipment > 50 kV (1719)	$ -	$ 625,178.94		$ 625,179	$ -	-$ 192,167		-$ 192,167	$ 433,012
47	1820	Distribution Station Equipment <50 kV	$ 6,450,525	-$ 1,880,385		$ 4,570,139	-$ 3,295,420	$ 730,154		-$ 2,565,267	$ 2,004,873
47	1820	Distribution Station Equipment <50 Kv (1821)		$ 1,880,385		$ 1,880,385		-$ 730,154		-$ 730,154	$ 1,150,232
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 33,882,693	$ 4,752,461		$ 38,635,154	-$ 18,818,635.88	-$ 4,153,741		-$ 22,972,377	$ 15,662,777
47	1830	Poles, Towers & Fixtures - (1831) Concrete		$ 2,918,249		$ 2,918,249		-$ 1,240,865		-$ 1,240,865	$ 1,677,384
47	1835	Overhead Conductors & Devices	$ 36,262,078	-$ 14,444,108		$ 21,817,970	-$ 17,483,656.71	$ 9,044,386		-$ 8,439,271	$ 13,378,699
47	1835	Overhead Conductors & Devices (1836)		$ 2,501,048		$ 2,501,048		-$ 816,410.15		-$ 816,410	$ 1,684,638
47	1835	Overhead Conductors & Devices (1837)		$ 1,901,699		$ 1,901,699		-$ 462,718.63		-$ 462,719	$ 1,438,980
47	1840	Underground Conduit	$ 12,764,491	-$ 3,691,583		$ 9,072,908	-$ 1,217,701	-$ 980,391		-$ 2,198,093	$ 6,874,815
47	1845	Underground Conductors & Devices	$ 60,998,236	$ 1,806,767		$ 62,805,003	-$ 37,786,395	$ 1,926,337		-$ 35,860,059	$ 26,944,944
47	1845	Underground Conductors & Devices (1846)		$ 1,884,816		$ 1,884,816		-$ 945,945		-$ 945,945	$ 938,871
47	1850	Line Transformers (1850) Polemount	$ 33,887,620	-$ 14,855,246		$ 19,032,374	-$ 18,935,946	$ 5,671,815		-$ 13,264,131	$ 5,768,243
47	1850	Line Transformers (1853) Padmount		$ 17,225,897		$ 17,225,897		-$ 8,042,465		-$ 8,042,465	$ 9,183,432
47	1855	Services (Overhead & Underground)	$ 4,629,063			$ 4,629,063	-$ 1,109,783	$ -		-$ 1,109,783	$ 3,519,280
47	1860	Meters	$ 2,645,456			$ 2,645,456	-$ 1,536,762	$ 695,835		-$ 840,927	$ 1,804,529
47	1860	Meters (Smart Meters)	$ 4,175,010			$ 4,175,010	$ -	-$ 695,835		-$ 695,835	$ 3,479,175
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -			$ -	$ -
47	1875	Street Lighting and Signal Systems				$ -				$ -	$ -
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 13,205,846			$ 13,205,846	-$ 2,455,533			-$ 2,455,533	$ 10,750,312
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,323,138			$ 1,323,138	-$ 851,763			-$ 851,763	$ 471,376
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,923,230			$ 1,923,230	-$ 1,110,846			-$ 1,110,846	$ 812,383
10	1930	Transportation Equipment (1931)		$ 548,320.97		$ 548,321		-$ 321,096		-$ 321,096	$ 227,225
10	1930	Transportation Equipment (1932) Large Trucks	$ 7,605,133	-$ 869,227		$ 6,735,906	-$ 4,563,046	$ 545,496		-$ 4,017,550	$ 2,718,356
10	1930	Transportation Equipment (1933) Trailers		$ 320,906.27		$ 320,906		-$ 224,401		-$ 224,401	$ 96,506
8	1935	Stores Equipment	$ 236,414			$ 236,414	-$ 196,641			-$ 196,641	$ 39,773
8	1940	Tools, Shop & Garage Equipment	$ 1,871,744			$ 1,871,744	-$ 1,457,230			-$ 1,457,230	$ 414,513
8	1945	Measurement & Testing Equipment	$ 204,006			$ 204,006	-$ 186,619			-$ 186,619	$ 17,387
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 502,920			$ 502,920	-$ 155,981			-$ 155,981	$ 346,939
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951			$ 72,951	-$ 67,314			-$ 67,314	$ 5,637
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 20,525,490			-$ 20,525,490	$ 5,493,615			$ 5,493,615	-$ 15,031,875
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 215,869,069**	**-$ 0**	**$ -**	**$ 215,869,069**	**-$ 111,886,125**	**$ 0**	**$ -**	**-$ 111,886,125**	**$ 103,982,944**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 215,869,069**	**-$ 0**	**$ -**	**$ 215,869,069**	**-$ 111,886,125**	**$ 0**	**$ -**	**-$ 111,886,125**	**$ 103,982,944**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 0**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 0

Notes:

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

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

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

4 The additions column (E) must not include construction work in progress (CWIP).

File Number:	EB-2014-0096
Exhibit:	2
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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year **2013**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,576,965	$ 114,742		$ 2,691,707	-$ 2,210,400	-$ 223,112		-$ 2,433,512	$ 258,195
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,603,587	$ 810		$ 1,604,396	-$ 811,064	-$ 57,098		-$ 868,162	$ 736,234
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013	$ -		$ 3,833,013	-$ 624,673	-$ 76,660		-$ 701,334	$ 3,131,679
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,502,386	$ 16,679		$ 1,519,065	-$ 176,327	-$ 36,280		-$ 212,606	$ 1,306,458
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 14,433	-$ 22,587		-$ 37,020	$ 9,935
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 187,727	-$ 13,339		-$ 201,066	$ 409,668
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 192,167	-$ 35,747		-$ 227,914	$ 397,265
47	1820	Distribution Station Equipment <50 kV	$ 4,570,139	$ 83,151	-$ 581,020	$ 4,072,270	-$ 2,565,267	-$ 80,230	$ 514,155	-$ 2,131,341	$ 1,940,929
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 1,880,385	$ 401,384		$ 2,281,769	-$ 730,154	-$ 63,263		-$ 793,416	$ 1,488,353
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 38,635,154	$ 1,900,121		$ 40,535,275	-$ 22,972,377	-$ 384,436		-$ 23,356,813	$ 17,178,462
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 2,918,249	$ 120,419		$ 3,038,668	-$ 1,240,865	-$ 32,680		-$ 1,273,545	$ 1,765,123
47	1835	Overhead Conductors & Devices	$ 21,817,970	$ 1,518,020		$ 23,335,990	-$ 8,439,271	-$ 254,999		-$ 8,694,270	$ 14,641,720
47	1835	Overhead Conductors & Devices (1836)	$ 2,501,048	$ 105,662		$ 2,606,710	-$ 816,410	-$ 318,767		-$ 1,135,177	$ 1,471,534
47	1835	Overhead Conductors & Devices (1837)	$ 1,901,699	$ 340,330		$ 2,242,028	-$ 462,719	-$ 64,078		-$ 526,796	$ 1,715,232
47	1840	Underground Conduit	$ 9,072,908	$ 590,887		$ 9,663,795	-$ 2,198,093	-$ 161,244		-$ 2,359,337	$ 7,304,457
47	1845	Underground Conductors & Devices	$ 62,805,003	$ 1,698,459		$ 64,503,462	-$ 35,860,059	-$ 1,626,237		-$ 37,486,296	$ 27,017,166
47	1845	Underground Conductors & Devices (1846)	$ 1,884,816	$ 186,760		$ 2,071,576	-$ 945,945	-$ 91,621		-$ 1,037,566	$ 1,034,010
47	1850	Line Transformers (1850) Polemount	$ 19,032,374	$ 432,676	-$ 143,205	$ 19,321,845	-$ 13,264,131	-$ 211,500	$ 143,205	-$ 13,332,426	$ 5,989,419
47	1850	Line Transformers (1853) Padmount	$ 17,225,897	$ 937,945	-$ 129,470	$ 18,034,372	-$ 8,042,465	-$ 467,996	$ 129,470	-$ 8,380,992	$ 9,653,381
47	1855	Services (Overhead & Underground)	$ 4,629,063	$ 800,998		$ 5,430,061	-$ 1,109,783	-$ 201,182		-$ 1,310,965	$ 4,119,097
47	1860	Meters	$ 2,645,456	$ 248,020		$ 2,893,476	-$ 840,927	-$ 146,928		-$ 987,855	$ 1,905,621
47	1860	Meters (Smart Meters)	$ 4,175,010	$ 27,477		$ 4,202,487	-$ 695,835	-$ 279,238		-$ 975,073	$ 3,227,414
47	1865	Other Installations on Customer's Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -	$ -		$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970	$ -		$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 13,205,846	$ 1,911,585		$ 15,117,431	-$ 2,455,533	-$ 231,984		-$ 2,687,517	$ 12,429,914
13	1910	Leasehold Improvements	$ 120,252	$ -		$ 120,252	-$ 120,252	$ -		-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,323,138	$ 170,426		$ 1,493,564	-$ 851,763	-$ 85,857		-$ 937,619	$ 555,945
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,923,230	$ 276,353		$ 2,199,583	-$ 1,110,846	-$ 304,065	$ 151	-$ 1,414,760	$ 784,823
10	1930	Transportation Equipment (1931)	$ 548,321	$ 180,597	$ (22,934)	$ 705,984	-$ 321,096	-$ 64,851	$ 22,056	-$ 363,891	$ 342,093
10	1930	Transportation Equipment (1932) Large Trucks	$ 6,735,906	$ 1,141,557	-$ 332,765	$ 7,544,698	-$ 4,017,550	-$ 213,067	$ 332,765	-$ 3,897,852	$ 3,646,846
10	1930	Transportation Equipment (1933) Trailers	$ 320,906	$ 8,420		$ 329,326	-$ 224,401	-$ 5,233		-$ 229,633	$ 99,693
8	1935	Stores Equipment	$ 236,414	$ -		$ 236,414	-$ 196,641	-$ 5,424		-$ 202,066	$ 34,349
8	1940	Tools, Shop & Garage Equipment	$ 1,871,744	$ 83,082		$ 1,954,826	-$ 1,457,230	-$ 75,413		-$ 1,532,643	$ 422,182
8	1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006	-$ 186,619	-$ 7,508		-$ 194,127	$ 9,879
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 502,920	$ 343,864		$ 846,784	-$ 155,981	-$ 19,419		-$ 175,400	$ 671,384
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 67,314	-$ 3,318		-$ 70,632	$ 2,319
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 20,525,490	-$ 991,373		-$ 21,516,863	$ 5,493,615	$ 810,261		$ 6,303,876	-$ 15,212,987
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 215,869,069**	**$ 12,649,050**	**-$ 1,209,394**	**$ 227,308,724**	**-$ 111,886,125**	**-$ 5,055,099**	**$ 1,141,802**	**-$ 115,799,421**	**$ 111,509,303**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 215,869,069**	**$ 12,649,050**	**-$ 1,209,394**	**$ 227,308,724**	**-$ 111,886,125**	**-$ 5,055,099**	**$ 1,141,802**	**-$ 115,799,421**	**$ 111,509,303**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,055,099**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 5,055,099

Notes:

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

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

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

4 The additions column (E) must not include construction work in progress (CWIP).

File Number:	EB-2014-0096
Exhibit:	2
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Schedule:	1
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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year **2013** **Using Old Useful Lives**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,576,965	$ 114,742		$ 2,691,707	-$ 2,210,400	-$ 223,112		-$ 2,433,512	$ 258,195
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,603,587	$ 810		$ 1,604,396	-$ 811,064	-$ 57,098		-$ 868,162	$ 736,234
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637			-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013	$ -		$ 3,833,013	-$ 624,673	-$ 76,660		-$ 701,334	$ 3,131,679
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,502,386	$ 16,679		$ 1,519,065	-$ 176,327	-$ 41,944		-$ 218,271	$ 1,300,794
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 14,433	-$ 1,026		-$ 15,459	$ 31,496
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 187,727	-$ 13,339		-$ 201,066	$ 409,668
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 192,167	-$ 13,655		-$ 205,822	$ 419,357
47	1820	Distribution Station Equipment <50 kV	$ 4,570,139	$ 83,151	-$ 581,020	$ 4,072,270	-$ 2,565,267	-$ 143,535	$ 514,155	-$ 2,194,646	$ 1,877,624
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 1,880,385	$ 401,384		$ 2,281,769	-$ 730,154	-$ 69,770		-$ 799,924	$ 1,481,845
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 38,635,154	$ 1,900,121		$ 40,535,275	-$ 22,972,377	-$ 1,187,111		-$ 24,159,488	$ 16,375,787
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 2,918,249	$ 120,419		$ 3,038,668	-$ 1,240,865	-$ 106,803		-$ 1,347,669	$ 1,690,999
47	1835	Overhead Conductors & Devices	$ 21,817,970	$ 1,518,020		$ 23,335,990	-$ 8,439,271	-$ 872,612		-$ 9,311,883	$ 14,024,107
47	1835	Overhead Conductors & Devices (1836)	$ 2,501,048	$ 105,662		$ 2,606,710	-$ 816,410	-$ 105,666		-$ 922,076	$ 1,684,634
47	1835	Overhead Conductors & Devices (1837)	$ 1,901,699	$ 340,330		$ 2,242,028	-$ 462,719	-$ 82,904		-$ 545,623	$ 1,696,405
47	1840	Underground Conduit	$ 9,072,908	$ 590,887		$ 9,663,795	-$ 2,198,093	-$ 374,690		-$ 2,572,783	$ 7,091,012
47	1845	Underground Conductors & Devices	$ 62,805,003	$ 1,698,459		$ 64,503,462	-$ 35,860,059	-$ 2,257,998		-$ 38,118,057	$ 26,385,405
47	1845	Underground Conductors & Devices (1846)	$ 1,884,816	$ 186,760		$ 2,071,576	-$ 945,945	-$ 69,445		-$ 1,015,390	$ 1,056,185
47	1850	Line Transformers (1850) Polemount	$ 19,032,374	$ 432,676	-$ 143,205	$ 19,321,845	-$ 13,264,131	-$ 531,142	$ 143,205	-$ 13,652,068	$ 5,669,777
47	1850	Line Transformers (1853) Padmount	$ 17,225,897	$ 937,945	-$ 129,470	$ 18,034,372	-$ 8,042,465	-$ 693,863	$ 129,470	-$ 8,606,859	$ 9,427,514
47	1855	Services (Overhead & Underground)	$ 4,629,063	$ 800,998		$ 5,430,061	-$ 1,109,783	-$ 201,182		-$ 1,310,965	$ 4,119,097
47	1860	Meters	$ 2,645,456	$ 248,020		$ 2,893,476	-$ 840,927	-$ 128,806		-$ 969,733	$ 1,923,743
47	1860	Meters (Smart Meters)	$ 4,175,010	$ 27,477		$ 4,202,487	-$ 695,835	-$ 279,238		-$ 975,073	$ 3,227,414
47	1865	Other Installations on Customer's Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -	$ -		$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970	$ -		$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 13,205,846	$ 1,911,585		$ 15,117,431	-$ 2,455,533	-$ 231,984		-$ 2,687,517	$ 12,429,914
13	1910	Leasehold Improvements	$ 120,252	$ -		$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,323,138	$ 170,426		$ 1,493,564	-$ 851,763	-$ 85,857		-$ 937,619	$ 555,945
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 1,923,230	$ 276,353		$ 2,199,583	-$ 1,110,846	-$ 304,065	$ 151	-$ 1,414,760	$ 784,823
10	1930	Transportation Equipment (1931)	$ 548,321	$ 180,597	$ (22,934)	$ 705,984	-$ 321,096	-$ 64,851	$ 22,056	-$ 363,891	$ 342,093
10	1930	Transportation Equipment (1932) Large Trucks	$ 6,735,906	$ 1,141,557	-$ 332,765	$ 7,544,698	-$ 4,017,550	-$ 488,147	$ 332,765	-$ 4,172,932	$ 3,371,766
10	1930	Transportation Equipment (1933) Trailers	$ 320,906	$ 8,420		$ 329,326	-$ 224,401	-$ 14,675		-$ 239,076	$ 90,250
8	1935	Stores Equipment	$ 236,414	$ -		$ 236,414	-$ 196,641	-$ 5,424		-$ 202,066	$ 34,349
8	1940	Tools, Shop & Garage Equipment	$ 1,871,744	$ 83,082		$ 1,954,826	-$ 1,457,230	-$ 75,413		-$ 1,532,643	$ 422,182
8	1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006	-$ 186,619	-$ 7,508		-$ 194,127	$ 9,879
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 502,920	$ 343,864		$ 846,784	-$ 155,981	-$ 107,082		-$ 263,064	$ 583,721
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 67,314	-$ 3,318		-$ 70,632	$ 2,319
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 20,525,490	-$ 991,373		-$ 21,516,863	$ 5,493,615	$ 810,261		$ 6,303,876	-$ 15,212,987
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 215,869,069**	**$ 12,649,050**	**-$ 1,209,394**	**$ 227,308,724**	**-$ 111,886,125**	**-$ 8,109,665**	**$ 1,141,802**	**-$ 118,853,987**	**$ 108,454,737**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 215,869,069**	**$ 12,649,050**	**-$ 1,209,394**	**$ 227,308,724**	**-$ 111,886,125**	**-$ 8,109,665**	**$ 1,141,802**	**-$ 118,853,987**	**$ 108,454,737**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 8,109,665**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 8,109,665

Notes:

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

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

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

4 The additions column (E) must not include construction work in progress (CWIP).

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2014

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 2,691,707	$ 737,966		$ 3,429,673	-$ 2,433,512	-$ 467,668		-$ 2,901,180	$ 528,493
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,604,396			$ 1,604,396	-$ 868,162	-$ 57,067		-$ 925,228	$ 679,168
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013	-$ 701,334	-$ 76,660		-$ 777,994	$ 3,055,019
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,519,065			$ 1,519,065	-$ 212,606	-$ 36,488		-$ 249,095	$ 1,269,970
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 37,020	-$ 10,841		-$ 47,860	-$ 905
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 201,066	-$ 13,339		-$ 214,406	$ 396,328
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 227,914	-$ 35,747		-$ 263,660	$ 361,519
47	1820	Distribution Station Equipment <50 kV	$ 4,072,270	$ 140,249.92		$ 4,212,520	-$ 2,131,341	-$ 59,366		-$ 2,190,707	$ 2,021,813
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 2,281,769	$ 111,787		$ 2,393,556	-$ 793,416	-$ 71,815		-$ 865,232	$ 1,528,325
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 40,535,275	$ 1,869,515.04		$ 42,404,790	-$ 23,356,813	-$ 422,133		-$ 23,778,945	$ 18,625,845
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,038,668	$ 62,224		$ 3,100,892	-$ 1,273,545	-$ 34,202		-$ 1,307,747	$ 1,793,144
47	1835	Overhead Conductors & Devices	$ 23,335,990	$ 673,087.52		$ 24,009,078	-$ 8,694,270	-$ 273,258		-$ 8,967,528	$ 15,041,550
47	1835	Overhead Conductors & Devices (1836)	$ 2,606,710	$ 138,346		$ 2,745,056	-$ 1,135,177	-$ 214,387		-$ 1,349,564	$ 1,395,492
47	1835	Overhead Conductors & Devices (1837)	$ 2,242,028	$ 30,399		$ 2,272,427	-$ 526,796	-$ 70,256		-$ 597,052	$ 1,675,375
47	1840	Underground Conduit	$ 9,663,795	$ 1,246,226		$ 10,910,021	-$ 2,359,337	-$ 179,616		-$ 2,538,953	$ 8,371,068
47	1845	Underground Conductors & Devices	$ 64,503,462	$ 2,441,444.96		$ 66,944,907	-$ 37,486,296	-$ 1,700,675		-$ 39,186,971	$ 27,757,936
47	1845	Underground Conductors & Devices (1846)	$ 2,071,576	$ 94,463		$ 2,166,039	-$ 1,037,566	-$ 52,929		-$ 1,090,495	$ 1,075,544
47	1850	Line Transformers (1850) Polemount	$ 19,321,845	$ 950,460.57		$ 20,272,305	-$ 13,332,426	-$ 221,021		-$ 13,553,447	$ 6,718,858
47	1850	Line Transformers (1853) Padmount	$ 18,034,372	$ 867,991		$ 18,902,364	-$ 8,380,992	-$ 498,830		-$ 8,879,822	$ 10,022,542
47	1855	Services (Overhead & Underground)	$ 5,430,061	$ 1,062,007		$ 6,492,068	-$ 1,310,965	-$ 238,442		-$ 1,549,407	$ 4,942,662
47	1860	Meters	$ 2,893,476	$ 602,414		$ 3,495,890	-$ 987,855	-$ 164,940		-$ 1,152,795	$ 2,343,094
47	1860	Meters (Smart Meters)	$ 4,202,487	$ 1,658,578		$ 5,861,065	-$ 975,073	-$ 465,231		-$ 1,440,304	$ 4,420,761
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 15,117,431	$ 1,500,485		$ 16,617,916	-$ 2,687,517	-$ 260,611		-$ 2,948,128	$ 13,669,788
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,493,564	$ 157,000		$ 1,650,564	-$ 937,619	-$ 100,229		-$ 1,037,849	$ 612,716
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,199,583	$ 302,295		$ 2,501,878	-$ 1,414,760	-$ 284,534		-$ 1,699,294	$ 802,583
10	1930	Transportation Equipment (1931)	$ 705,984	$ -		$ 705,984	-$ 363,891	-$ 68,307		-$ 432,198	$ 273,786
10	1930	Transportation Equipment (1932) Large Trucks	$ 7,544,698	$ 650,000		$ 8,194,698	-$ 3,897,852	-$ 303,228		-$ 4,201,081	$ 3,993,617
10	1930	Transportation Equipment (1933) Trailers	$ 329,326	$ 22,000		$ 351,326	-$ 229,633	-$ 6,134		-$ 235,767	$ 115,560
8	1935	Stores Equipment	$ 236,414	$ 75,000		$ 311,414	-$ 202,066	-$ 9,174		-$ 211,240	$ 100,174
8	1940	Tools, Shop & Garage Equipment	$ 1,954,826	$ 67,000		$ 2,021,826	-$ 1,532,643	-$ 78,815		-$ 1,611,458	$ 410,367
8	1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006	-$ 194,127	-$ 5,092		-$ 199,219	$ 4,787
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 846,784	$ 227,500		$ 1,074,284	-$ 175,400	-$ 40,434		-$ 215,834	$ 858,450
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 70,632	-$ 2,072		-$ 72,704	$ 247
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 21,516,863	-$ 900,000		-$ 22,416,863	$ 6,303,876	$ 845,482		$ 7,149,359	-$ 15,267,505
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 227,308,724**	**$ 14,788,439**	**$ -**	**$ 242,097,163**	**-$ 115,799,421**	**-$ 5,678,060**	**$ -**	**-$ 121,477,482**	**$ 120,619,682**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 227,308,724**	**$ 14,788,439**	**$ -**	**$ 242,097,163**	**-$ 115,799,421**	**-$ 5,678,060**	**$ -**	**-$ 121,477,482**	**$ 120,619,682**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,678,060**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 5,678,060

Notes:

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

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

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

4 The additions column (E) must not include construction work in progress (CWIP).

File Number:	EB-2014-0096
Exhibit:	2
Tab:	1
Schedule:	1
Page:	7
Date:	29-Aug-14

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2014

Using Old Useful Lives

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,691,707	$ 737,966		$ 3,429,673	-$ 2,433,512	-$ 467,668		-$ 2,901,180	$ 528,493
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,604,396			$ 1,604,396	-$ 868,162	-$ 57,067		-$ 925,228	$ 679,168
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013	-$ 701,334	-$ 76,660		-$ 777,994	$ 3,055,019
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,519,065			$ 1,519,065	-$ 218,271	-$ 42,152		-$ 260,423	$ 1,258,642
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 15,459	-$ 1,026		-$ 16,484	$ 30,471
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 201,066	-$ 13,339		-$ 214,406	$ 396,328
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 205,822	-$ 13,655		-$ 219,477	$ 405,702
47	1820	Distribution Station Equipment <50 kV	$ 4,072,270.47	$ 140,249.92		$ 4,212,520	-$ 2,194,646	-$ 124,657		-$ 2,319,303	$ 1,893,217
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 2,281,769	$ 111,787		$ 2,393,556	-$ 799,924	-$ 80,034		-$ 879,958	$ 1,513,599
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 40,535,274.96	$ 1,869,515.04		$ 42,404,790	-$ 24,159,488	-$ 1,244,066		-$ 25,403,553	$ 17,001,237
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,038,668	$ 62,224		$ 3,100,892	-$ 1,347,669	-$ 108,794		-$ 1,456,463	$ 1,644,429
47	1835	Overhead Conductors & Devices	$ 23,335,990.29	$ 673,087.52		$ 24,009,078	-$ 9,311,883	-$ 907,833		-$ 10,219,717	$ 13,789,361
47	1835	Overhead Conductors & Devices (1836)	$ 2,606,710	$ 138,346		$ 2,745,056	-$ 922,076	-$ 110,546		-$ 1,032,622	$ 1,712,434
47	1835	Overhead Conductors & Devices (1837)	$ 2,242,028	$ 30,399		$ 2,272,427	-$ 545,623	-$ 90,195		-$ 635,818	$ 1,636,609
47	1840	Underground Conduit	$ 9,663,795	$ 1,246,226		$ 10,910,021	-$ 2,572,783	-$ 411,432		-$ 2,984,215	$ 7,925,806
47	1845	Underground Conductors & Devices	$ 64,503,461.77	$ 2,441,444.96		$ 66,944,907	-$ 38,118,057	-$ 2,270,044		-$ 40,388,101	$ 26,556,806
47	1845	Underground Conductors & Devices (1846)	$ 2,071,576	$ 94,463		$ 2,166,039	-$ 1,015,390	-$ 73,256		-$ 1,088,647	$ 1,077,392
47	1850	Line Transformers (1850) Polemount	$ 19,321,844.87	$ 950,460.57		$ 20,272,305	-$ 13,652,068	-$ 537,277		-$ 14,189,345	$ 6,082,961
47	1850	Line Transformers (1853) Padmount	$ 18,034,372	$ 867,991		$ 18,902,364	-$ 8,606,859	-$ 706,503		-$ 9,313,362	$ 9,589,002
47	1855	Services (Overhead & Underground)	$ 5,430,061	$ 1,062,007		$ 6,492,068	-$ 1,310,965	-$ 238,442		-$ 1,549,407	$ 4,942,662
47	1860	Meters	$ 2,893,476	$ 602,414		$ 3,495,890	-$ 969,733	-$ 152,822		-$ 1,122,556	$ 2,373,334
47	1860	Meters (Smart Meters)	$ 4,202,487	$ 1,658,578		$ 5,861,065	-$ 975,073	-$ 465,231		-$ 1,440,304	$ 4,420,761
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -			$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 15,117,431	$ 1,500,485		$ 16,617,916	-$ 2,687,517	-$ 260,611		-$ 2,948,128	$ 13,669,788
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,493,564	$ 157,000		$ 1,650,564	-$ 937,619	-$ 100,229		-$ 1,037,849	$ 612,716
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,199,583	$ 302,295		$ 2,501,878	-$ 1,414,760	-$ 284,534		-$ 1,699,294	$ 802,583
10	1930	Transportation Equipment (1931)	$ 705,984	$ -		$ 705,984	-$ 363,891	-$ 68,307		-$ 432,198	$ 273,786
10	1930	Transportation Equipment (1932) Large Trucks	$ 7,544,698	$ 650,000		$ 8,194,698	-$ 4,172,932	-$ 639,749		-$ 4,812,682	$ 3,382,016
10	1930	Transportation Equipment (1933) Trailers	$ 329,326	$ 22,000		$ 351,326	-$ 239,076	-$ 16,927		-$ 256,003	$ 95,323
8	1935	Stores Equipment	$ 236,414	$ 75,000		$ 311,414	-$ 202,066	-$ 9,174		-$ 211,240	$ 100,174
8	1940	Tools, Shop & Garage Equipment	$ 1,954,826	$ 67,000		$ 2,021,826	-$ 1,532,643	-$ 78,815		-$ 1,611,458	$ 410,367
8	1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006	-$ 194,127	-$ 5,092		-$ 199,219	$ 4,787
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 846,784	$ 227,500		$ 1,074,284	-$ 263,064	-$ 199,196		-$ 462,260	$ 612,025
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 70,632	-$ 2,072		-$ 72,704	$ 247
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 21,516,863	-$ 900,000		-$ 22,416,863	$ 6,303,876	$ 845,483		$ 7,149,359	-$ 15,267,505
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 227,308,724**	**$ 14,788,439**	**$ -**	**$ 242,097,163**	**-$ 118,853,987**	**-$ 9,011,923**	**$ -**	**-$ 127,865,910**	**$ 114,231,253**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 227,308,724**	**$ 14,788,439**	**$ -**	**$ 242,097,163**	**-$ 118,853,987**	**-$ 9,011,923**	**$ -**	**-$ 127,865,910**	**$ 114,231,253**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 9,011,923**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 9,011,923

Notes:

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

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

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

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	EB-2014-0096
Exhibit:	2
Tab:	1
Schedule:	1
Page:	8
Date:	29-Aug-14

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2015

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 3,429,673	$ 368,740		$ 3,798,413	-$ 2,901,180	-$ 78,909		-$ 2,980,089	$ 818,324
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,604,396			$ 1,604,396	-$ 925,228	-$ 57,067		-$ 982,295	$ 622,101
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013	-$ 777,994	-$ 76,660		-$ 854,654	$ 2,978,359
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,519,065			$ 1,519,065	-$ 249,095	-$ 36,488		-$ 285,583	$ 1,233,482
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 47,860	$ 905		-$ 46,955	-$ 0
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 214,406	-$ 13,339		-$ 227,745	$ 382,989
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 263,660	-$ 35,747		-$ 299,407	$ 325,772
47	1820	Distribution Station Equipment <50 kV	$ 4,212,520			$ 4,212,520	-$ 2,190,707	-$ 60,924		-$ 2,251,631	$ 1,960,889
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 2,393,556			$ 2,393,556	-$ 865,232	-$ 73,679		-$ 938,910	$ 1,454,646
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 42,404,790	$ 2,219,067		$ 44,623,857	-$ 23,778,945	-$ 462,431		-$ 24,241,376	$ 20,382,481
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,100,892			$ 3,100,892	-$ 1,307,747	-$ 35,210		-$ 1,342,958	$ 1,757,934
47	1835	Overhead Conductors & Devices	$ 24,009,078	$ 1,164,812		$ 25,173,890	-$ 8,967,528	-$ 288,574		-$ 9,256,102	$ 15,917,788
47	1835	Overhead Conductors & Devices (1836)	$ 2,745,056	$ 101,000		$ 2,846,056	-$ 1,349,564	-$ 210,713		-$ 1,560,277	$ 1,285,779
47	1835	Overhead Conductors & Devices (1837)	$ 2,272,427	$ 30,162		$ 2,302,589	-$ 597,052	-$ 71,266		-$ 668,318	$ 1,634,271
47	1840	Underground Conduit	$ 10,910,021	$ 836,870		$ 11,746,890	-$ 2,538,953	-$ 200,447		-$ 2,739,399	$ 9,007,491
47	1845	Underground Conductors & Devices	$ 66,944,907	$ 2,444,065		$ 69,388,972	-$ 39,186,971	-$ 1,245,374		-$ 40,432,345	$ 28,956,627
47	1845	Underground Conductors & Devices (1846)	$ 2,166,039	$ 561,196		$ 2,727,235	-$ 1,090,495	-$ 59,599		-$ 1,150,094	$ 1,577,141
47	1850	Line Transformers (1850) Polemount	$ 20,272,305	$ 885,008		$ 21,157,314	-$ 13,553,447	-$ 243,965		-$ 13,797,412	$ 7,359,901
47	1850	Line Transformers (1853) Padmount	$ 18,902,364	$ 662,260		$ 19,564,624	-$ 8,879,822	-$ 522,072		-$ 9,401,894	$ 10,162,730
47	1855	Services (Overhead & Underground)	$ 6,492,068	$ 1,018,443		$ 7,510,511	-$ 1,549,407	-$ 280,051		-$ 1,829,457	$ 5,681,053
47	1860	Meters	$ 3,495,890	$ 284,541		$ 3,780,431	-$ 1,152,795	-$ 186,489		-$ 1,339,285	$ 2,441,146
47	1860	Meters (Smart Meters)	$ 5,861,065	$ 143,150		$ 6,004,215	-$ 1,440,304	-$ 405,162		-$ 1,845,466	$ 4,158,749
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 16,617,916	$ 44,000		$ 16,661,916	-$ 2,948,128	-$ 281,047		-$ 3,229,174	$ 13,432,741
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,650,564	$ 32,824		$ 1,683,388	-$ 1,037,849	-$ 97,373		-$ 1,135,222	$ 548,167
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,501,878	$ 240,248		$ 2,742,126	-$ 1,699,294	-$ 236,679		-$ 1,935,974	$ 806,152
10	1930	Transportation Equipment (1931)	$ 705,984	$ 114,086		$ 820,069	-$ 432,198	-$ 65,721		-$ 497,918	$ 322,151
10	1930	Transportation Equipment (1932) Large Trucks	$ 8,194,698	$ 513,992		$ 8,708,690	-$ 4,201,081	-$ 342,028		-$ 4,543,109	$ 4,165,582
10	1930	Transportation Equipment (1933) Trailers	$ 351,326	$ 70,800		$ 422,126	-$ 235,767	-$ 8,454		-$ 244,220	$ 177,906
8	1935	Stores Equipment	$ 311,414	$ -		$ 311,414	-$ 211,240	-$ 8,799		-$ 220,039	$ 91,375
8	1940	Tools, Shop & Garage Equipment	$ 2,021,826	$ 60,803		$ 2,082,628	-$ 1,611,458	-$ 78,073		-$ 1,689,531	$ 393,097
8	1945	Measurement & Testing Equipment	$ 204,006	$ 1,000		$ 205,006	-$ 199,219	-$ 3,239		-$ 202,459	$ 2,548
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 1,074,284	$ 215,000		$ 1,289,284	-$ 215,834	-$ 51,496		-$ 267,331	$ 1,021,953
8	1955	Communication Equipment (Smart Meters)	$ -	$ 1,000		$ 1,000	$ -			$ -	$ 1,000
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 72,704	-$ 249		-$ 72,954	-$ 2
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 22,416,863	-$ 827,800		-$ 23,244,663	$ 7,149,359	$ 879,539		$ 8,028,897	-$ 15,215,766
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 242,097,163**	**$ 11,185,268**	**$ -**	**$ 253,282,431**	**-$ 121,477,482**	**-$ 4,936,879**	**$ -**	**-$ 126,414,360**	**$ 126,868,071**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 242,097,163**	**$ 11,185,268**	**$ -**	**$ 253,282,431**	**-$ 121,477,482**	**-$ 4,936,879**	**$ -**	**-$ 126,414,360**	**$ 126,868,071**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 4,936,879**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,936,879

Notes:

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

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

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

4 The additions column (E) must not include construction work in progress (CWIP).

Gross Assets (PP&E) and Accumulated Depreciation

Materiality Threshold

In accordance with section 2.5.4 of the Filing Requirements, NPEI has applied a materiality threshold of 0.5% of distribution revenue requirement in its analysis of property, plant and equipment. Table 2-2 below shows NPEI's materiality threshold calculation:

Table 2-2: Materiality Threshold

Service Revenue Requirement	30,971,328
(from Revenue Deficiency Calculation)	
Less Revenue Offsets	(1,596,475)
Base Revenue Requirement	**29,374,853**
Other	29,374,853
Total	**29,374,853**
Variance Calculation 0.5% of Distribution Revenue Requirement	**146,874**

NPEI has used a materiality threshold of $145,000 in this Exhibit.

Table 2-3 below provides a summary of gross asset by function and Table 2-4 provides a detailed breakdown by major plant account for each function.

Table 2-3: Summary of Gross Assets by Function

Description	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Distribution Plant	196,104,961	193,859,001	202,313,437	210,868,729	222,817,922	233,168,497
General Plant	27,472,708	27,166,325	29,900,569	33,660,752	36,662,032	37,955,785
Contributions & Grants	(18,331,077)	(19,052,603)	(20,525,491)	(21,516,864)	(22,416,864)	(23,244,664)
Intangible Plant	3,897,069	3,961,704	4,180,551	4,296,103	5,034,069	5,402,809
Total - Gross Assets	209,143,662	205,934,427	215,869,067	227,308,720	242,097,159	253,282,427

Table 2-4: Gross Assets by Account

UsoA	Description	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
	Land & Buildings						
1805	Land	507,273	507,273	507,273	507,273	507,273	507,273
1808	Buildings	111,638	111,638	111,638	111,638	111,638	111,638
1905	Land	508,970	508,970	508,970	508,970	508,970	508,970
1908	Buildings	12,458,371	12,580,151	13,205,846	15,117,430	16,617,915	16,661,915
1910	Leasehold Improvements	120,252	120,252	120,252	120,252	120,252	120,252
	Sub-total	13,706,504	13,828,284	14,453,979	16,365,563	17,866,048	17,910,048
	Transformer & Distribution Stations						
1815	Transformer Station Equipment	6,602,001	6,602,001	6,618,267	6,634,946	6,634,946	6,634,946
1820	Distribution Station Equipment	5,688,900	5,783,876	6,450,525	6,354,040	6,606,077	6,606,077
	Sub-total	12,290,901	12,385,876	13,068,792	12,988,985	13,241,022	13,241,022
	Poles & Wires						
1830	Poles, Towers & Fixtures	33,108,476	32,407,878	41,553,404	43,573,943	45,505,682	47,724,750
1835	Overhead Conductors & Devices	33,896,171	34,623,385	26,220,717	28,184,729	29,026,561	30,322,536
1840	underground Conduit	12,860,825	11,962,395	9,072,907	9,663,794	10,910,020	11,746,889
1845	Underground Conductors & Devices	57,913,186	58,652,495	64,689,819	66,575,038	69,110,946	72,116,208
	Sub-total	137,778,658	137,646,153	141,536,847	147,997,504	154,553,209	161,910,383
	Line Transformers						
1850	Line Transformers	33,463,894	32,882,342	36,258,271	37,356,217	39,174,669	40,721,937
	Sub-total	33,463,894	32,882,342	36,258,271	37,356,217	39,174,669	40,721,937
	Services & Meters						
1855	Services	4,353,853	4,191,989	4,629,063	5,430,061	6,492,068	7,510,510
1860	Meters	8,217,655	6,752,640	6,820,465	7,095,962	9,356,954	9,784,645
	Sub-total	12,571,508	10,944,629	11,449,528	12,526,023	15,849,022	17,295,155
	IT Assets						
1920	Computer Equipment Hardware	3,174,697	3,130,612	3,501,322	3,777,674	4,079,969	4,320,217
	Sub-total	3,174,697	3,130,612	3,501,322	3,777,674	4,079,969	4,320,217
	Equipment						
1915	Office Furniture & Equipment	1,234,983	1,211,189	1,323,139	1,493,564	1,650,564	1,683,388
1930	Transportation Equipment	6,816,897	6,444,484	7,605,133	8,580,008	9,252,008	9,950,885
1935	Stores Equipment	226,597	236,414	236,414	236,414	311,414	311,414
1940	Tools, Shop & Garage Equipment	1,753,675	1,738,843	1,871,744	1,954,826	2,021,826	2,082,629
1945	Measurement & Testing Equipment	188,846	204,006	204,006	204,006	204,006	205,006
1955	Communications Equipment	168,596	170,581	502,921	846,785	1,074,285	1,289,285
1960	Miscellaneous Equipment	72,952	72,951	72,951	72,951	72,951	73,951
1980	System supervisor Equipment	128,961	128,961	128,961	128,961	128,961	128,961
	Sub-total	10,591,507	10,207,430	11,945,268	13,517,515	14,716,015	15,725,519
	Other General Assets						
1995	Contributions and Grants	(18,331,077)	(19,052,603)	(20,525,491)	(21,516,864)	(22,416,864)	(23,244,664)
	Sub-total	(18,331,077)	(19,052,603)	(20,525,491)	(21,516,864)	(22,416,864)	(23,244,664)
	Intangible Assets						
1611	Computer Software	2,298,899	2,363,534	2,576,964	2,691,706	3,429,672	3,798,413
1612	Land Rights	1,598,170	1,598,171	1,603,587	1,604,397	1,604,397	1,604,397
	Sub-total	3,897,069	3,961,704	4,180,551	4,296,103	5,034,069	5,402,809
	Total - Gross Assets	209,143,662	205,934,427	215,869,067	227,308,720	242,097,159	253,282,427

Year-over-year analyses on material gross assets balance variances are given below.

2011 Actual versus 2011 Board Approved

Table 2-5: Gross Assets Variances – 2011 Actual vs. 2011 Board Approved

UsoA	Description	2011 Board Approved	2011 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	0
1905	Land	508,970	508,970	0
1908	Buildings	12,458,371	12,580,151	121,779
1910	Leasehold Improvements	120,252	120,252	0
	Sub-total	13,706,504	13,828,284	121,780
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,602,001	6,602,001	(0)
1820	Distribution Station Equipment	5,688,900	5,783,876	94,976
	Sub-total	12,290,901	12,385,876	94,976
	Poles & Wires			
1830	Poles, Towers & Fixtures	33,108,476	32,407,878	(700,598)
1835	Overhead Conductors & Devices	33,896,171	34,623,385	727,214
1840	Underground Conduit	12,860,825	11,962,395	(898,430)
1845	Underground Conductors & Devices	57,913,186	58,652,495	739,309
	Sub-total	137,778,658	137,646,153	(132,505)
	Line Transformers			
1850	Line Transformers	33,463,894	32,882,342	(581,552)
	Sub-total	33,463,894	32,882,342	(581,552)
	Services & Meters			
1855	Services	4,353,853	4,191,989	(161,864)
1860	Meters	8,217,655	6,752,640	(1,465,015)
	Sub-total	12,571,508	10,944,629	(1,626,879)
	IT Assets			
1920	Computer Equipment Hardware	3,174,697	3,130,612	(44,086)
	Sub-total	3,174,697	3,130,612	(44,086)
	Equipment			
1915	Office Furniture & Equipment	1,234,983	1,211,189	(23,793)
1930	Transportation Equipment	6,816,897	6,444,484	(372,413)
1935	Stores Equipment	226,597	236,414	9,817
1940	Tools, Shop & Garage Equipment	1,753,675	1,738,843	(14,833)
1945	Measurement & Testing Equipment	188,846	204,006	15,160
1955	Communications Equipment	168,596	170,581	1,986
1960	Miscellaneous Equipment	72,952	72,951	(1)
1980	System supervisor Equipment	128,961	128,961	(0)
	Sub-total	10,591,507	10,207,430	(384,078)
	Other General Assets			
1995	Contributions and Grants	(18,331,077)	(19,052,603)	(721,526)
	Sub-total	(18,331,077)	(19,052,603)	(721,526)
	Intangible Assets			
1611	Computer Software	2,298,899	2,363,534	64,635
1612	Land Rights	1,598,170	1,598,171	1
	Sub-total	3,897,069	3,961,704	64,635
	Total - Gross Assets	209,143,662	205,934,427	(3,209,235)

Account 1830 – Poles, Towers & Fixtures

Variance = ($700,598)

For NPEI's 2011 overhead projects, due to changes in scope, urgent projects (for example, the wind storm in April 2011) or demand projects, the actual costs were higher on the conductor and lower on the poles than originally budgeted.

Significant projects contributing to this variance are:

- Project 2011-0003 - Montrose – McLeod to Canadian – ($114K)
- Project 2011-0005 – Riall St. Rebuild – ($70K)
- Project 2011-0007 – Murray/Culp/Main Rebuilds – ($97K)
- Project 2011-0008 – Kalar Extend NS&T ROW to Beaverdams – ($64K)
- Project 2011-1010 – Pole Replacements – ($305K)

Account 1835 – Overhead Conductors & Devices

Variance = $727,214

For NPEI's 2011 overhead projects, due to changes in scope, urgent projects (for example, the wind storm in April 2011) or demand projects, the actual costs were higher on the conductor and lower on the poles than originally budgeted.

Significant projects contributing to this variance are:

- Project 2011-0007 – Murray/Culp/Main Rebuilds - $106K
- Project 2011-0008 – Kalar Extend NS&T ROW to Beaverdams - $45K
- Project 2011-0011 – Sectionalize 4 areas - $163K
- Project 2011-0013 – Smithville Station Upgrades - $56K
- Project 2011-0052 – Mountain Road 3 Phase Extension - $33K
- Project 2011-0065 – Wind Storm Damage April 28 - $209K

Account 1840 – Underground Conduit

Variance = ($898,430)

For NPEI's 2011 underground projects, due to changes in scope or demand projects, the actual costs were higher on the conductor and lower on the conduit than originally budgeted.

Significant projects contributing to this variance are:

- Project 2011-0001 – Robinson St Rebuild – ($49K)
- Project 2011-0002 – Lundy's Lane Underground Rebuild – ($180K)
- Project 2011-0007 – Murray/Culp/Main Rebuilds – ($167K)
- Project 2011-0020 – Kiosk Conversions – ($117K)

Account 1845 – Underground Conductor

Variance = $739,309

For NPEI's 2011 underground projects, due to changes in scope or demand projects, the actual costs were higher on the conductor and lower on the conduit than originally budgeted.

Significant projects contributing to this variance are:

- Project 2011-0001 – Robinson St Rebuild - $527K
- Project 2011-0020 – Kiosk Conversions - $278K.

Account 1850 – Line Transformers

Variance = ($581,552)

. Significant projects contributing to this variance are:

- Project 2011-0002 – Lundy's Lane Underground Rebuild – ($120K)
- Project 2011-0020 – Kiosk Conversions – ($157K).
- Project 2011-0007 – Murray/Culp/Main Rebuilds – ($117K)
- Project 2011-0003 - Montrose – McLeod to Canadian – ($32K)

Account 1855 – Services

Variance = ($161,864)

Significant projects contributing to this variance are:

- Project 2011-0004 – Lundy's Lane Montrose- Kalar – ($100K)

Account 1860 – Meters

Variance = ($1,465,015)

Significant projects contributing to this variance are:

- Project 2011-1006 – Metering Capital Costs – ($108K)
- Gross cost of conventional meters stranded removed from rate base – ($1,456).

Account 1995 – Contributions and Grants

Variance = ($721,526)

NPEI's 2011 Board Approved capital contributions were as follows:

- $250K from City/Region due to road relocation
- $300K from subdivision developers
- $300K from demand work.

NPEI's 2011 Actual capital contributions from the City/Region was $292K higher than budgeted. The 2011 Actual capital contributions from subdivision developers was $105K higher than budgeted. The balance of the variance is due to demand work.

Further details on NPEI's 2011 capital projects are provided later in this schedule. (See "Capital Project Descriptions" beginning at page 32).

Account 1930 – Transportation Equipment

Variance = ($372,413)

NPEI's Actual 2011 vehicle costs were $541,643, compared to $462,963 for 2011 Board Approved. The variance in the gross asset balances are due to disposals during 2011.

Further details on NPEI's 2011 general plant costs are provided later in this schedule. (See "General Plant" beginning at page 69).

2012 Actual versus 2011 Actual

Table 2-6: Gross Assets Variances – 2012 Actual vs. 2011 Actual

UsoA	Description	2011 Actual	2012 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	12,580,151	13,205,846	625,695
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	13,828,284	14,453,979	625,695
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,602,001	6,618,267	16,266
1820	Distribution Station Equipment	5,783,876	6,450,525	666,649
	Sub-total	12,385,876	13,068,792	682,915
	Poles & Wires			
1830	Poles, Towers & Fixtures	32,407,878	33,882,694	1,474,815
1835	Overhead Conductors & Devices	34,623,385	36,262,078	1,638,693
1840	Underground Conduit	11,962,395	12,764,490	802,096
1845	Underground Conductors & Devices	58,652,495	60,998,236	2,345,741
	Sub-total	137,646,153	143,907,498	6,261,345
	Line Transformers			
1850	Line Transformers	32,882,342	33,887,620	1,005,278
	Sub-total	32,882,342	33,887,620	1,005,278
	Services & Meters			
1855	Services	4,191,989	4,629,063	437,074
1860	Meters	6,752,640	6,820,465	67,825
	Sub-total	10,944,629	11,449,528	504,899
	IT Assets			
1920	Computer Equipment Hardware	3,130,612	3,501,322	370,710
	Sub-total	3,130,612	3,501,322	370,710
	Equipment			
1915	Office Furniture & Equipment	1,211,189	1,323,139	111,949
1930	Transportation Equipment	6,444,484	7,605,133	1,160,649
1935	Stores Equipment	236,414	236,414	-
1940	Tools, Shop & Garage Equipment	1,738,843	1,871,744	132,901
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	170,581	502,921	332,339
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	10,207,430	11,945,268	1,737,838
	Other General Assets			
1995	Contributions and Grants	(19,052,603)	(20,525,491)	(1,472,887)
	Sub-total	(19,052,603)	(20,525,491)	(1,472,887)
	Intangible Assets			
1611	Computer Software	2,363,534	2,576,964	213,431
1612	Land Rights	1,598,171	1,603,587	5,416
	Sub-total	3,961,704	4,180,551	218,847
	Total - Gross Assets	205,934,427	215,869,067	9,934,640

Account 1820 – Distribution Station Equipment

Variance = $666,649

Significant projects contributing to this variance are:

- Project 2012-0012 – Greenlane MS – $143K
- Project 2012-0013 – Smithville MS – $216K

Account 1830 – Poles, Towers & Fixtures

Variance = $1,474,815

Significant projects contributing to this variance are:

- Project 2012-0001 - Montrose – Kinsman to Lundy's Lane – $171K
- Project 2012-0005 – Riall St. Rebuild – $59K
- Project 2012-0007 – Murray/Dixon Rebuilds – $172K
- Project 2012-0008 – Kalar – Woodbine to Thorold Stone - $94K
- Project 2012-0014 – Victoria Ave. Voltage Conversion - $78K
- Project 2012-1007 – Sustainment Work – $70K
- Project 2012-1008 – Demand Work – $80K
- Project 2012-1010 – Pole Replacement - $539K

Account 1835 – Overhead Conductors & Devices

Variance = $ 1,638,693

Significant projects contributing to this variance are:

- Project 2012-0001 - Montrose – Kinsman to Lundy's Lane – $125K
- Project 2012-0005 – Riall St. Rebuild – $167K
- Project 2012-0007 – Murray/Dixon Rebuilds – $275K
- Project 2012-0008 – Kalar – Woodbine to Thorold Stone - $184K
- Project 2012-0014 – Victoria Ave. Voltage Conversion - $66K
- Project 2012-1007 – Sustainment Work – $93K
- Project 2012-1008 – Demand Work – $69K

- Project 2012-1010 – Pole Replacement - $213K

Account 1840 – Underground Conduit

Variance = $802,096

Significant projects contributing to this variance are:

- Project 2012-0001 - Montrose – Kinsman to Lundy's Lane – $147K
- Project 2012-0002 – Lundy's Lane / Ker St. UG Replacement – $85K
- Project 2012-0003 – Kalar MTS K-M-1 K-M-5 Egress – $25K
- Project 2012-0008 – Kalar – Woodbine to Thorold Stone - $29K
- Project 2012-0020 – Kiosk Replacement Program - $102
- Project 2012-0072 – Drummond & Lundy's Lane conflicts – $75K
- Project 2012-1007 – Sustainment Work – $53K

Account 1845 – Underground Conductor

Variance = $ 2,345,741

Significant projects contributing to this variance are:

- Project 2011-0096 – Thundering Waters Subdivision - $132K
- Project 2012-0001 - Montrose – Kinsman to Lundy's Lane – $127K
- Project 2012-0002 – Lundy's Lane / Ker St. UG Replacement – $171K
- Project 2012-0003 – Kalar MTS K-M-1 K-M-5 Egress – $91K
- Project 2012-0005 – Riall St. Rebuild - $58K
- Project 2012-0006 - Switchgear Replacement Program - $301K
- Project 2012-0007 – Murray/Dixon Rebuild - $62K
- Project 2012-0008 – Kalar – Woodbine to Thorold Stone - $36K
- Project 2012-0020 – Kiosk Replacement Program - $406K
- Project 2012-0072 – Drummond & Lundy's Lane conflicts – $172K
- Project 2012-1007 – Sustainment Work – $132K
- Project 2012-1008 – Demand Work – $97K

- Project 2012-1010 – Pole Replacement - $58K

Account 1850 – Line Transformers

Variance = $1,005,278

Significant projects contributing to this variance are:

- Project 2011-0096 – Thundering Waters Subdivision - $35K
- Project 2012-0005 – Riall St. Rebuild - $29K
- Project 2012-0007 – Murray/Dixon Rebuild - $ 55K
- Project 2012-0008 – Kalar – Woodbine to Thorold Stone - $18K
- Project 2012-0014 – Victoria Ave. Voltage Conversion - $27K
- Project 2012-0020 – Kiosk Replacement Program - $172K
- Project 2012-0038 – Chippawa West Subdivision Ph II - $70K
- Project 2012-1007 – Sustainment Work – $161K
- Project 2012-1008 – Demand Work – $331K
- Project 2012-1010 – Pole Replacement - $32K

Account 1855 – Services

Variance = $437,074

Significant projects contributing to this variance are:

- Project 2012-0005 – Riall St. Rebuild - $31K
- Project 2012-0007 – Murray/Dixon Rebuild - $ 54K
- Project 2012-1008 – Demand Work – $134K
- Project 2012-1009 – Services – Non-Project - $207K

Account 1995 – Contributions and Grants

Variance = ($1,472,887)

This represents capital contributions collected in accordance with NPEI's conditions of service from City / Region for road relocation works, subdivision developers and other customers for demand work.

Further details on NPEI's 2012 capital projects are provided later in this schedule. (See "Capital Project Descriptions" beginning at page 32).

Account 1908 – Buildings

Variance = $625,695

Account 1920 – Hardware

Variance = $370,710

Account 1930 – Transportation Equipment

Variance = $1,160,649

Account 1955 – Communications Equipment

Variance = $332,339

Account 1611 – Computer Software

Variance = $213,431

Further details on NPEI's 2012 general plant costs are provided later in this schedule. (See "General Plant" beginning at page 69).

2013 Actual versus 2012 Actual

Table 2-7: Gross Assets Variances – 2013 Actual vs. 2012 Actual

UsoA	Description	2012 Actual	2013 Actual	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	13,205,846	15,117,430	1,911,585
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	14,453,979	16,365,563	1,911,585
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,618,267	6,634,946	16,679
1820	Distribution Station Equipment	6,450,525	6,354,040	(96,485)
	Sub-total	13,068,792	12,988,985	(79,806)
	Poles & Wires			
1830	Poles, Towers & Fixtures	41,553,404	43,573,943	2,020,540
1835	Overhead Conductors & Devices	26,220,717	28,184,729	1,964,012
1840	Underground Conduit	9,072,907	9,663,794	590,886
1845	Underground Conductors & Devices	64,689,819	66,575,038	1,885,219
	Sub-total	141,536,847	147,997,504	6,460,657
	Line Transformers			
1850	Line Transformers	36,258,271	37,356,217	1,097,946
	Sub-total	36,258,271	37,356,217	1,097,946
	Services & Meters			
1855	Services	4,629,063	5,430,061	800,998
1860	Meters	6,820,465	7,095,962	275,497
	Sub-total	11,449,528	12,526,023	1,076,495
	IT Assets			
1920	Computer Equipment Hardware	3,501,322	3,777,674	276,353
	Sub-total	3,501,322	3,777,674	276,353
	Equipment			
1915	Office Furniture & Equipment	1,323,139	1,493,564	170,426
1930	Transportation Equipment	7,605,133	8,580,008	974,875
1935	Stores Equipment	236,414	236,414	-
1940	Tools, Shop & Garage Equipment	1,871,744	1,954,826	83,082
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	502,921	846,785	343,864
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	11,945,268	13,517,515	1,572,247
	Other General Assets			
1995	Contributions and Grants	(20,525,491)	(21,516,864)	(991,373)
	Sub-total	(20,525,491)	(21,516,864)	(991,373)
	Intangible Assets			
1611	Computer Software	2,576,964	2,691,706	114,742
1612	Land Rights	1,603,587	1,604,397	810
	Sub-total	4,180,551	4,296,103	115,552
	Total - Gross Assets	215,869,067	227,308,720	11,439,654

Note: In 2012, NPEI engaged KPMG to assist with determining the level of PP&E componentization required under IFRS, establishing updated useful lives and examining whether any changes to overhead capitalization were required. As a result of this analysis, NPEI determined that some reclassification among distribution plant USoA accounts was necessary. Accordingly, NPEI booked the following entry as at January 1, 2013:

1830-Poles, Towers and Fixtures	7,670,710
1835-Overhead Conductors and Devices	(10,041,361)
1840-Underground Conduit	(3,691,583)
1845-Underground Conductors and Devices	3,691,583
1850-Line Transformers	2,370,651
	-

To provide for greater clarity in 2013 over 2012 variance analysis, this reclassification entry has been added to the 2012 closing balance in Table 2-7 above.

Account 1830 – Poles, Towers & Fixtures

Variance = $2,020,540

Significant projects contributing to this variance are:

- Project 2013-0005 – 12-M-6 Replacement – $137K
- Project 2013-0007 – Murray/Culp Rebuilds – $231K
- Project 2013-0008 – High St - Dorchester - $139K
- Project 2013-0011 – Dorchester Garden St. to McMillan - $136K
- Project 2013-0014 – Victoria Ave. Voltage Conversion - $38K
- Project 2013-0021 – Beacon Inn Jordan - $93K
- Project 2013-0100 – Kalar at Rideau - $43K
- Project 2013-1007 – Sustainment Work Niagara area – $104K
- Project 2013-1008 – Demand Work Niagara area – $43K
- Project 2013-1010 – Pole Replacement Niagara area - $337K
- Project 2013-2007 – Sustainment Work west area– $40K
- Project 2013-2008 – Demand Work west area – $50K
- Project 2013-2010 – Pole Replacement west area - $86K

Account 1835 – Overhead Conductors & Devices

Variance = $ 1,964,012

Significant projects contributing to this variance are:

- Project 2013-0005 – 12-M-6 Replacement – $102K
- Project 2013-0007 – Murray/Culp Rebuilds – $262K
- Project 2013-0008 – High St - Dorchester - $253K
- Project 2013-0011 – Dorchester Garden St. to McMillan - $ 50K
- Project 2013-0014 – Victoria Ave. Voltage Conversion - $93K
- Project 2013-0017 – Station #8 - $21K
- Project 2013-0021 – Beacon Inn Jordan - $75K
- Project 2013-0085 – Storm Damage July 19 - $107K
- Project 2013-1007 – Sustainment Work Niagara area – $82K
- Project 2013-1008 – Demand Work Niagara area – $47K
- Project 2013-1010 – Pole Replacement Niagara area - $229K
- Project 2013-2007 – Sustainment Work west area– $42K
- Project 2013-2008 – Demand Work west area – $56K

Account 1840 – Underground Conduit

Variance = $590,886

Significant projects contributing to this variance are:

- Project 2013-0005 - 12-M-6 Replacement – $125K
- Project 2013-0008 – High St - Dorchester - $68K
- Project 2013-0020 – Kiosk Replacement Program - $ 54K
- Project 2013-0021 – Beacon Inn Jordan - $15K
- Project 2013-0100 – Kalar at Rideau - $72K
- Project 2013-1007 – Sustainment Work Niagara area – $100K
- Project 2013-1008 – Demand Work Niagara area – $27K
- Project 2013-1010 – Pole Replacement Niagara area - $38K

Account 1845 – Underground Conductor

Variance = $ 1,885,219

Significant projects contributing to this variance are:

- Project 2013-0005 – 12-M-6 Replacement – $126K
- Project 2013-0006 – Switchgear Replacement - $150K
- Project 2013-0007 – Murray/Culp Rebuilds – $80K
- Project 2013-0008 – High St - Dorchester - $122K
- Project 2013-0020 – Kiosk Replacement Program - $ 364K
- Project 2013-0021 – Beacon Inn Jordan - $24K
- Project 2013-0100 – Kalar at Rideau - $38K
- Project 2013-1007 – Sustainment Work Niagara area – $124K
- Project 2013-1008 – Demand Work Niagara area – $40K
- Project 2013-1010 – Pole Replacement Niagara area - $65K
- Project 2013-2008 – Demand Work west area – $89K

Account 1850 – Line Transformers

Variance = $1,097,946

Significant projects contributing to this variance are:

- Project 2013-0005 – 12-M-6 Replacement – $48K
- Project 2013-0007 – Murray/Culp Rebuilds – $65K
- Project 2013-0006 – Switchgear Replacement - $42K
- Project 2013-0008 – High St - Dorchester - $22K
- Project 2013-0014 – Victoria Ave. Voltage Conversion - $27K
- Project 2013-0021 – Beacon Inn Jordan - $44K
- Project 2013-0085 – Storm Damage July 19 - $53K
- Project 2013-1007 – Sustainment Work Niagara area – $73K
- Project 2013-1008 – Demand Work Niagara area – $116K
- Project 2013-1010 – Pole Replacement Niagara area - $61K
- Project 2013-2007 – Sustainment Work west area– $62K

- Project 2013-2008 – Demand Work west area – $139K

Account 1855 – Services

Variance = $800,998

Significant projects contributing to this variance are:

- Project 2013-0007 – Murray/Culp Rebuilds – $79K
- Project 2013-1008 – Demand Work Niagara area – $204K
- Project 2013-1009 – Subdivisions Niagara area - $208K
- Project 2013-2008 – Demand Work west area – $194K
- Project 2013-2009 – Subdivisions west area - $84K

Account 1860 – Meters

Variance = $275,497

Significant projects contributing to this variance are:

- Project 2013-0019 – Sixteen Rd HAF Energy Metering – $24K
- Project 2013-1006 – Metering Costs - Capital – $122K

Account 1995 – Contributions and Grants

Variance = ($991,373)

This represents capital contributions collected in accordance with NPEI's conditions of service from City / Region for road relocation works, subdivision developers and other customers for demand work.

Further details on NPEI's 2013 capital projects are provided later in this schedule. (See "Capital Project Descriptions" beginning at page 32).

Account 1908 – Buildings

Variance = $1,911,585

Account 1920 – Hardware

Variance = $276,353

Account 1930 – Transportation Equipment

Variance = $974,875

Account 1955 – Communications Equipment

Variance = $343,864

Further details on NPEI's 2013 general plant costs are provided later in this schedule. (See "General Plant" beginning at page 69).

2014 Bridge Year versus 2013 Actual

Table 2-8: Gross Assets Variances – 2014 Bridge vs. 2013 Actual

UsoA	Description	2013 Actual	2014 Bridge	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	15,117,430	16,617,915	1,500,485
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	16,365,563	17,866,048	1,500,485
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,634,946	6,634,946	-
1820	Distribution Station Equipment	6,354,040	6,606,077	252,037
	Sub-total	12,988,985	13,241,022	252,037
	Poles & Wires			
1830	Poles, Towers & Fixtures	43,573,943	45,505,682	1,931,739
1835	Overhead Conductors & Devices	28,184,729	29,026,561	841,832
1840	Underground Conduit	9,663,794	10,910,020	1,246,226
1845	Underground Conductors & Devices	66,575,038	69,110,946	2,535,908
	Sub-total	147,997,504	154,553,209	6,555,705
	Line Transformers			
1850	Line Transformers	37,356,217	39,174,669	1,818,452
	Sub-total	37,356,217	39,174,669	1,818,452
	Services & Meters			
1855	Services	5,430,061	6,492,068	1,062,007
1860	Meters	7,095,962	9,356,954	2,260,992
	Sub-total	12,526,023	15,849,022	3,322,999
	IT Assets			
1920	Computer Equipment Hardware	3,777,674	4,079,969	302,295
	Sub-total	3,777,674	4,079,969	302,295
	Equipment			
1915	Office Furniture & Equipment	1,493,564	1,650,564	157,000
1930	Transportation Equipment	8,580,008	9,252,008	672,000
1935	Stores Equipment	236,414	311,414	75,000
1940	Tools, Shop & Garage Equipment	1,954,826	2,021,826	67,000
1945	Measurement & Testing Equipment	204,006	204,006	-
1955	Communications Equipment	846,785	1,074,285	227,500
1960	Miscellaneous Equipment	72,951	72,951	-
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	13,517,515	14,716,015	1,198,500
	Other General Assets			
1995	Contributions and Grants	(21,516,864)	(22,416,864)	(900,000)
	Sub-total	(21,516,864)	(22,416,864)	(900,000)
	Intangible Assets			
1611	Computer Software	2,691,706	3,429,672	737,966
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	4,296,103	5,034,069	737,966
	Total - Gross Assets	227,308,720	242,097,159	14,788,439

Account 1820 – Distribution Station Equipment

Variance = $252,037

Significant projects contributing to this variance are:

- Station #8 Rehab - $252K

Account 1830 – Poles, Towers & Fixtures

Variance = $1,931,739

Significant projects contributing to this variance are:

- Dorchester Rebuild - $37K
- Simcoe St - $43K
- Welland River crossing – $19K
- Station #22 - Loads South Of Pew – $156K
- Jordan Rd. Red Maple to QEW - $185K
- Crawford St. Area Rebuild - $175K
- King St. 27.6kV Ext. at Martin - $39K
- PCB Transformer Changeouts - $150K
- Pole Changeouts - $632K
- Demand - $135K
- Road Relocation - $257K
- Sustainment - $90K

Account 1835 – Overhead Conductors & Devices

Variance = $ 841,832

Significant projects contributing to this variance are:

- Dorchester Rebuild - $63K
- Simcoe St - $66K
- Welland River crossing - $32K
- Station #22 - Loads South Of Pew - $149K

- Jordan Rd. Red Maple to QEW - $51K
- Crawford St. Area Rebuild - $193K
- King St. 27.6kV Ext. at Martin - $45K
- Demand - $35K
- Sectionalizing - $100K
- Sustainment - $48K

Account 1840 – Underground Conduit

Variance = $1,246,226

Significant projects contributing to this variance are:

- Welland River crossing - $220K
- Rolling Acres - Phase 1 - $459K
- Fallsview - Ferry to Robinson - $203K
- Kiosks - $53K
- Demand - $75K
- Road Relocation - $120K
- Sustainment - $100K

Account 1845 – Underground Conductor

Variance = $ 2,535,908

Significant projects contributing to this variance are:

- Dorchester Rebuild - $122K
- Simcoe St - $191K
- Welland River Xing - $337K
- Rolling Acres - Phase 1 - $310K
- Station #22 - Loads South Of Pew - $62K
- Fallsview - Ferry to Robinson - $92K
- 3M28,29 Feeder Egress - $246K

- Kiosks - $345K
- Switchgear - $100K
- Demand - $325K
- Road Relocation - $123K
- Sustainment - $163K
- Subdivision Connections - $118K

Account 1850 – Line Transformers

Variance = $1,818,452

Significant projects contributing to this variance are:

- Dorchester Rebuild - $77K
- Welland River crossing - $58K
- Station #22 - Loads South Of Pew - $50K
- Fallsview - Ferry to Robinson - $20K
- Jordan Rd. Red Maple to QEW - $130K
- Crawford St. Area Rebuild - $52K
- PCB Transformer Changeouts - $373K
- Pole Changeouts – $132K
- Kiosks - $213K
- Demand - $630K
- Subdivision Connections - $61K

Account 1855 – Services

Variance = $1,062,007

Significant projects contributing to this variance are:

- Dorchester Rebuild - $64K
- Simcoe St - $56K

- Welland River crossing - $36K
- Station #22 - Loads South Of Pew - $99K
- Jordan Rd. Red Maple to QEW - $33K
- Crawford St. Area Rebuild - $97K
- PCB Transformer Changeouts - $43K
- Demand - $211K
- Road Relocation – $20K
- Subdivision Lots – $200K
- Subdivision Connections - $21K
- Lot Rebates - $150K

Account 1860 – Metering

Variance = $2,260,992

Significant projects contributing to this variance are:

- 3M28, 29 Feeder Egress - $172K
- Wholesale Metering - $300K
- General Metering - $130K

NPEI notes that $1,659K of the metering variance is due to costs that were previously recorded in the smart meter variance accounts being transferred to rate base in 2014, as approved in the Board's Decision and Order in NPEI's Smart Meter Application (EB-2013-0359).

Account 1995 – Contributions and Grants

Variance = ($900,000)

NPEI anticipates collecting $900,000 in capital contributions in 2014, as follows:

- Fallsview - Ferry to Robinson - $100K
- Demand Work - $450K

- Road Relocation - $125K
- Subdivisions – $200K
- Metering - $25K

Further details on NPEI's 2014 capital projects are provided later in this schedule. (See "Capital Project Descriptions" beginning at page 32).

Account 1908 – Buildings
Variance = $1,500,485

Account 1915 – Office Furniture & Equipment
Variance = $157,000

Account 1920 – Hardware
Variance = $302,295

Account 1930 – Transportation Equipment
Variance = $672,000

Account 1955 – Communications Equipment
Variance = $227,500

Account 1611 – Computer Software
Variance = $737,966
NPEI notes that $239K of the computer software variance is due to costs that were previously recorded in the smart meter variance accounts being transferred to rate base in 2014, as approved in the Board's Decision and Order in NPEI's Smart Meter Application (EB-2013-0359).

Further details on NPEI's 2014 general plant costs are provided later in this schedule. (See "General Plant" beginning at page 69).

2015 Test Year versus 2014 Bridge Year

Table 2-9: Gross Assets Variances – 2015 Test vs. 2014 Bridge

UsoA	Description	2014 Bridge	2015 Test	Variance $
	Land & Buildings			
1805	Land	507,273	507,273	-
1808	Buildings	111,638	111,638	-
1905	Land	508,970	508,970	-
1908	Buildings	16,617,915	16,661,915	44,000
1910	Leasehold Improvements	120,252	120,252	-
	Sub-total	17,866,048	17,910,048	44,000
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	6,634,946	6,634,946	-
1820	Distribution Station Equipment	6,606,077	6,606,077	-
	Sub-total	13,241,022	13,241,022	-
	Poles & Wires			
1830	Poles, Towers & Fixtures	45,505,682	47,724,750	2,219,067
1835	Overhead Conductors & Devices	29,026,561	30,322,536	1,295,975
1840	Underground Conduit	10,910,020	11,746,889	836,870
1845	Underground Conductors & Devices	69,110,946	72,116,208	3,005,262
	Sub-total	154,553,209	161,910,383	7,357,173
	Line Transformers			
1850	Line Transformers	39,174,669	40,721,937	1,547,268
	Sub-total	39,174,669	40,721,937	1,547,268
	Services & Meters			
1855	Services	6,492,068	7,510,510	1,018,443
1860	Meters	9,356,954	9,784,645	427,691
	Sub-total	15,849,022	17,295,155	1,446,134
	IT Assets			
1920	Computer Equipment Hardware	4,079,969	4,320,217	240,248
	Sub-total	4,079,969	4,320,217	240,248
	Equipment			
1915	Office Furniture & Equipment	1,650,564	1,683,388	32,824
1930	Transportation Equipment	9,252,008	9,950,885	698,878
1935	Stores Equipment	311,414	311,414	-
1940	Tools, Shop & Garage Equipment	2,021,826	2,082,629	60,803
1945	Measurement & Testing Equipment	204,006	205,006	1,000
1955	Communications Equipment	1,074,285	1,289,285	215,000
1960	Miscellaneous Equipment	72,951	73,951	1,000
1980	System supervisor Equipment	128,961	128,961	-
	Sub-total	14,716,015	15,725,519	1,009,504
	Other General Assets			
1995	Contributions and Grants	(22,416,864)	(23,244,664)	(827,800)
	Sub-total	(22,416,864)	(23,244,664)	(827,800)
	Intangible Assets			
1611	Computer Software	3,429,672	3,798,413	368,740
1612	Land Rights	1,604,397	1,604,397	-
	Sub-total	5,034,069	5,402,809	368,740
	Total - Gross Assets	242,097,159	253,282,427	11,185,268

Account 1830 – Poles, Towers & Fixtures

Variance = $2,219,067

Significant projects contributing to this variance are:

- Jordan Phase 2 - $278K
- King St. 27.6kV Ext at Martin - $45K
- Station 22 Loads S of Pew Carry - $47K
- Station 22 Loads N of Pew - $173K
- Crawford St. Area Carry - $39K
- Beck Road - $61K
- Willodell Rebuild - $119K
- Frederica - $89K
- Willoughby Drive - $142K
- Willoughby Dr Extension - $144K
- Pole Changeouts - $342K
- PCB Transformer Changeouts - $79K
- Demand - $143K
- Reclosers - $72K
- Road Relocation - $233K
- Sustainment - $205K

Account 1835 – Overhead Conductors & Devices

Variance = $ 1,295,975

Significant projects contributing to this variance are:

- Jordan Phase 2 - $44K
- King St. 27.6kV Ext at Martin - $47K
- Station 22 Loads S of Pew Carry - $47K
- Station 22 Loads N of Pew - $152K
- Crawford St. Area Carry - $92K

- Beck Road - $74K
- Willodell Rebuild - $144K
- Frederica - $146K
- Willoughby Drive - $132K
- Willoughby Dr Extension - $126K
- Demand - $35K
- Sectionalizing - $73K
- Reclosers - $28K
- Sustainment - $120K

Account 1840 – Underground Conduit

Variance = $836,870

Significant projects contributing to this variance are:

- Frederica - $39K
- Rolling Acres - $355K
- Kiosks - $56K
- Demand - $115K
- Road Relocation - $131K
- Sustainment - $140K

Account 1845 – Underground Conductor

Variance = $ 3,005,262

Significant projects contributing to this variance are:

- Frederica - $320K
- Rolling Acres - $216K
- Willoughby Dr Extension - $51K
- Niagara Parks Commission - $819K
- NWTC Metering - $290K
- Kiosks - $347K

- Switchgear - $187K
- Demand - $255K
- Road Relocation - $119K
- Sustainment - $205K
- Subdivision Connections - $165K

Account 1850 – Line Transformers

Variance = $1,547,268

Significant projects contributing to this variance are:

- Jordan Phase 2 - $97K
- Station 22 Loads N of Pew - $53K
- Crawford St. Area Carry - $33K
- Willodell Rebuild - $39K
- Frederica - $26K
- Willoughby Drive - $54K
- Willoughby Dr Extension - $33K
- Pole Changeouts - $78K
- PCB Transformer Changeouts - $416K
- Kiosks - $229K
- Switchgear - $52K
- Demand - $370K
- Subdivision Connections - $54K

Account 1855 – Services

Variance = $1,018,443

Significant projects contributing to this variance are:

- Jordan Phase 2 - $30K
- Station 22 Loads S of Pew Carry - $50K

- Station 22 Loads N of Pew - $119K
- Crawford St. Area Carry - $119K
- Frederica - $55K
- Willoughby Drive - $33K
- Willoughby Dr Extension - $30K
- Road Relocation - $18K
- Subdivision Lots - $275K
- Subdivision Connections - $92K
- Lot Rebates - $150K

Account 1860 – Metering

Variance = $427,691

Significant projects contributing to this variance are:

- Demand - $90K
- Metering - $194K
- Purchase of Smart Meters - $143K

Account 1995 – Contributions and Grants

Variance = ($827,800)

NPEI anticipates collecting $827,800 in capital contributions in 2015, as follows:

- Jordan Phase 2 - $53K
- Demand Work - $450K
- Road Relocation - $125K
- Subdivisions – $200K

Further details on NPEI's 2015 capital projects are provided later in this schedule. (See "Capital Project Descriptions" beginning at page 32).

Account 1920 – Hardware
Variance = $240,248

Account 1930 – Transportation Equipment
Variance = $698,878

Account 1955 – Communications Equipment
Variance = $215,000

Account 1611 – Computer Software
Variance = $368,740

Further details on NPEI's 2015 general plant costs are provided later in this schedule. (See "General Plant" beginning at page 69).

Capital Project Descriptions

System Access

SA42

Demand based system reinforcements for new commercial service connections.

2010 Actual Cost	**$435,393**
2011 Actual Cost	**$573,712**
2012 Actual Cost	**$711,788**
2013 Actual Cost	**$1,011,493**
2014 Budgeted Cost	**$1,410,778**
2015 Budgeted Cost	**$1,007,500**
Total	**$5,150,664**

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connection/Extension

2010 Actual Cost	**$161,656**
2011 Actual Cost	**$389,962**
2012 Actual Cost	**$269,890**
2013 Actual Cost	**$177,811**
Total	**$999,318**

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New Upgrade Services

2010 Actual Cost	**$331,699**
2011 Actual Cost	**$458,414**
2012 Actual Cost	**$196,437**
2013 Actual Cost	**$84,734**
Total	**$1,071,284**

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

SA43

Line Relocations due to Municipal Road Improvement requirements.

2010 Actual Cost	**$472,209**
2011 Actual Cost	**$295,727**
2012 Actual Cost	**$236,975**
2013 Actual Cost	**$355,572**
2014 Budgeted Cost	**$539,910**
2015 Budgeted Cost	**$500,000**
Total	**$2,400,394**

There are various small projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Beginning in 2014, the City of Niagara Falls increased its budget for road improvements. Based on discussions with the City on forecast infrastructure planning, NPEI has included an amount of $500,000 per year from 2015 to 2019 for line relocations. This is reflected in NPEI's Distribution System Plan and Appendix 2-AB.

Subdivisions

2010 Actual Cost	**$682,640**
2011 Actual Cost	**$290,295**
2012 Actual Cost	**$518,409**
2013 Actual Cost	**$703,212**
2014 Budgeted Cost	**$400,000**
2015 Budgeted Cost	**$587,004**
Total	**$3,181,561**

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

SA55

Niagara Parks Commission

2015 Budgeted Cost	**$818,905**

The Niagara Parks Commission is a Provincial Entity located within the City of Niagara Falls which oversees all Operations associated with the Tourist Attractions under their jurisdiction. This also includes a significant Electrical Distribution System within its boundaries. Negotiations are currently underway, initiated by the Customer, for NPEI to assume the primary distribution system up to the low voltage bushings of the transformers. The NPC does not have Staff qualified to operate and maintain the high voltage system, and would like to expand upon an Operating Agreement currently executed between both parties, where NPEI would own, maintain, and operate the high voltage system on their behalf. From the Customers due-diligence standpoint, and NPEI's capability to respond to the Customers emergency and growth requirements, with appropriate Staff, Equipment, and Material Stock, a mutually beneficial system expansion would result, increasing Public Safety and reliability. The 2015 budgeted amount represents NPEI’s cost to acquire the assets.

SA38

City of Niagara Falls - Kalar Rd – Catalina to Rideau

2013 Actual Cost $169,530 Project 2013-0100

Scope of work requires the removal of secondary service crossing poles which are in conflict with the municipality's road widening plan. The existing overhead secondary service crossings will be replaced with underground secondary conductor in conjunction with civil works to permit road construction.

SA39

Overhead circuit reconstruction of side Streets off Dorchester Road from Morrison Street, north to the former NS&T ROW.

2010 Actual Cost $180,976 Project 2010-0016

Due to the age and clearance issues between the 4.16 KV and 13.8KV circuits in this area it is necessary to eliminate the three-phase overhead spun 5KV cable along Dorchester Road. The load from this line will be transferred to the existing 12M32 distribution circuit by the placement of two pole mounted step down transformers along Cherrygrove. There will also be a small rebuild/conversion of line will on Dianne/Queensway Gardens. The spun primary cable will then be removed from the existing poles on Dorchester which will remain in service until the CNF finalizes the road widening design.

SA40

Drummond @ Lundy's Lane Conflicts

2012 Actual Cost $267,123 Project 2011-0072

Scope of work involves the removal of legacy 4.16kV underground conductor, kiosks, and associated equipment. The legacy facilities will be replaced with 15kV underground primary conductor and pad-mounted transformation. The installation of 15kV conductor will permit conversion of the area to the 13.8kV system in the future. Construction is required due to construction conflicts with regional road works at the intersection of Drummond Road and Lundy's Lane.

SA41

Kalar Road—Catalina to Beaverdams Rd.

2010 Actual Cost	**$164,362**	**Project 2010-0009**
2011 Actual Cost	**$483,044**	**Project 2011-0009, 2011-0109**
Total	**$647,406**	

The rebuild of 400 meters of existing double circuit between Catalina Dr. and Lundy's Lane and 800 meters of existing single circuit 3-phase 15 KV pole line between Lundy's Lane and Beaverdams Road. 1200 meters of new double circuit concrete pole line will be built on the West side of Kalar Road using the KM3 and KM7 Feeders between Lundy's & Beaverdams. Construction is required due to conflicts with CNF road widening works and the need for additional circuit intertie capabilities between Kalar M.T.S. and Stanley T.S. Additional intertie capability will improve feeder load balancing and contingency capabilities.

Oakwood Drive Relocation

2010 Actual Cost	**$159,399**	**Project 2010-0053**

Scope of work involves the replacement of 800 meters of existing 3M30 15kV single circuit 3-phase pole line with a double circuit pole line using the KM6 and KM2 feeders. Construction is required due to construction conflicts with the Smart Centre road works, and system requirements for additional circuit intertie.

SA49

South Pelham Street—Fonthill Downtown Core

2010 Actual Cost $816,593 Project 2010-0026

Scope involves the replacement of 500 meters of existing 3-phase overhead 5kV distribution feeder F5 in downtown Fonthill. Construction is required due to conflicts with municipal road widening/improvement works. A combination of overhead and underground distribution plant will be installed based on final negotiations with the municipality.

System Renewal

SR4

Fonthill-Pelham St. D.S. Replacement Completion

2010 Actual Cost $226,046 Project 2010-0025

Replacement of the 27.6/4.16 kV distribution station equipment supplying the Town of Fonthill. This work includes a new 27.6/8.32-4.16 kV 5000 KVA Transformer (which could be moved elsewhere on the system in the future), and new protection equipment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

SR10

Campden D.S. Feeder Egress Poles

2010 Actual Cost $207,208 Project 2010-0017

The annual pole testing inspection program has identified the requirement for the replacement of the poles outside Campden DS that support the incoming supply and distribution Feeders. This project has been isolated from the pole replacement program due to the complexity of the amount of equipment supported. Also to maintain proper working clearances and strain support. Construction standards will need to be developed for the framing required.

SR12

Campden DS Oil Containment

2011 Actual Cost $214,586 Project 2011-0017

Replacement of the distribution station protection equipment at Campden DS that supplies portions of the surrounding area of Campden. The existing transformer will continue to be utilized in the design based on results of the asset condition assessment. The scope of work includes a new protection equipment, ground grid, and oil containment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

SR5

Municipal Substation Rehabilitation

2011 Actual Cost	**$361,959**	**Project 2011-0013**
2012 Actual Cost	**$274,090**	
Total	**$636,049**	

Replacement of the 27.6/8.32kV distribution station equipment supplying portions of the area of Smithville. This work includes a new 27.6/8.32kV 5000 KVA transformer, new protection equipment, ground grid, and oil containment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

SR6

Municipal Sub-station Rehabilitation

Greenlane MS

2012 Actual Cost	**$275,300**	**Project 2012-0012**
2013 Actual Cost	**$197,505**	
Total	**$472,805**	

Station St. MS

2011 Actual Cost	**$ 41,711**	**Project 2011-0022**
2012 Actual Cost	**$137,209**	
2013 Actual Cost	**$100,331**	
Total	**$279,250**	

Greenlane MS

Replacement of the 27.6/8.32kV distribution station equipment supplying portions of the area of Lincoln running along the QEW. This work includes a new 27.6/8.32kV 5000 KVA transformer, new protection equipment, ground grid, and oil containment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

Station St. MS

Replacement of the distribution station protection equipment at Station St. DS that supplies portions of town of Fonthill. The existing transformer will continue to be utilized in the design based on results of the asset condition assessment. The scope of work includes a new protection equipment and grounding. The existing LV protection equipment is of 1950's vintage and consists of oil circuit breakers in a confined space presenting numerous safety hazards for workers.

SR7

Station #22 North of Pew

2015 Budgeted Cost $507,139

Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1953, including 38 pole changes, new single-phase (1.2KM) & secondary (1.4KM) circuits, 8 distribution transformer replacements resulting in the upgraded supply to about 119 residential customers directly, in the area bounded by Dorchester Rd., Lundy's Lane, Brookfield Ave., & Garden St. System benefits include reconstruction to eliminate Municipal Sub-station Stn. #22 constructed in 1969, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities, improved equipment clearance, and increased Customer reliability.

SR8

Station #22 South of Pew

2015 Budgeted Cost	**$143,724**

Completion of the Rebuild Project which targets 1.70 kilometers of urban distribution line installed in 1953, including 58 pole changes, new single (1.70KM) and secondary (1.70KM) circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 125 residential customers directly, in the area bounded by Dorchester Rd., Lundy's Lane, Brookfield Ave, & Coach Dr. System benefits include reconstruction to eliminate Municipal Sub-station Stn. #22 constructed in 1969, targeted for decommissioning, replacement of aging equipment, future voltage conversions opportunities, improved equipment clearance, and increased Customer reliability.

SR9

Municipal Sub-station Rehabilitation

Station #8

2013 Actual Cost	**$191,113**	**Project 2013-0017**
2014 Budgeted Cost	**$252,037**	
Total	**$443,150**	

Replacement of the 13.8kV/8.32kV distribution station equipment supplying portions of Niagara Falls around the Robinson Street / Allendale Street area. This work includes a new protection equipment, ground grid, and oil containment. The existing 5000kVA power transformer will be re-utilized as part of the design based on the results of the asset condition assessment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

SR11

Vineland / NWMTS / Beamsville TS Feeder Sectionalizing

2011 Actual Cost $156,718 Project 2011-0011

The review of existing feeder configurations, which egress from Stanley & Murray T.S. & Kalar M.T.S. has identified the requirement for the installation of additional pole mounted ganged load break switches within the system to replace existing aerial operated single phase switches. The existing switches are in locations that intertie circuits This will provide greater capability to perform circuit sectionalizing during outage events in order to minimize the affected area.

SR13

Lundy's Lane Line Rebuild—Kalar Road to Montrose Road

2011 Actual Cost $156,213 Project 2011-0004

The project scope includes the replacement of plant based upon preliminary design submissions for municipal consent in 2010 to replace the 1 km of directly buried underground feeder with an overhead pole line. Equipment replacements are required due to a number of cable faults experienced on this section of feeder, which is approaching end of life. The replacement includes extending the existing KM7 13.8kV 3-phase line on concrete poles on the North side of Lundy's Lane between Kalar and Montrose Road.

SR14

Required overhead line rebuild of deteriorated facilities identified by the pole condition survey.

Murray bounded by Culp/Dunn/Main/Drummond

2011 Actual Cost $395,970 Project 2011-0007

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2011 this program targets the remainder of approximately 5 kilometers of urban distribution line requiring 150 pole changes, the installation of new single phase primary and secondary circuits, 30 distribution transformer replacements and results in upgraded supply to about 400 residential customers.

SR15

Riall Street Rebuild—St. Paul Ave to Dorchester Road

2011 Actual Cost	**$143,116**
2012 Actual Cost	**$357,948**
Total	**$501,064**

Project scope involves the replacement of a section of existing directly buried 12M33 15kV underground primary cable from Stanley T.S. with an overhead pole line. Equipment replacements are required due to the plant approaching end of life. The project also includes the rebuild of an existing 4.16kV 3-phase pole line on the north side of Riall Street to 3-phase 13.8KV. The rebuild will replace the underground primary cable and eliminate a 4.16KV radial-feed providing an 8.0kV source to recently rebuilt lines between Riall & Stamford Green Drive.

SR16

Underground Primary Replacement-Rear Lot Lundy's Lane & Ker St.

2012 Actual Cost $356,580 Project 2012-0002

Replacement of existing directly buried underground distribution facilities approaching end of life. The distribution facilities have inherent operational issues of legacy construction. They are located within the commercial core between Drummond Road and Franklin Ave. The proposal includes the introduction of multiple points of supply from the recently rebuilt line on Ker Street. Construction includes a 450 meter long duct bank for extension of 200 Amp 13,800 Volt distribution feeders using the Murray Station 3M51. The construction will eliminate existing switchgear assemblies at Station #25, Station #53, Station #38, and Station #21, and enable a 13.8 KV source for future High St. voltage conversion.

SR17

Montrose Road Line Rebuild— Lundy's Lane to Kinsmen Court

2012 Actual Cost $608,128 Project 2012-0001

The project scope includes the replacement of 1.1km of existing overhead plant on the east side of Montrose Road with a new pole line in the same location. Replacements are required due to capacity limitations of the existing primary conductor, the requirement of a 600 Amp source to existing switching Station #28, and issues associated with existing underground distribution between Kalar and Montrose Road. The project includes an underground extension from the last pole south of Lundy's Lane to the switching station on the North East corner of Lundy's Lane and Montrose Road.

SR18

Required overhead line rebuild of deteriorated facilities identified by the pole condition survey.

Murray/Dixon

2012 Actual Cost $633,981 Project 2012-0007

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2012 this program targets the remainder of approximately 5 kilometers of urban distribution line requiring 150 pole changes, the installation of new single phase primary and secondary circuits, 30 distribution transformer replacements and results in upgraded supply to about 400 residential customers.

SR19

Victoria Avenue @ the Q.E.W.

2012 Actual Cost $173,042 Project 2012-0014

2013 Actual Cost <u>$170,305</u>

Total	**<u>$343,346</u>**

The Project Scope involves the construction of approximately 1km of new 3-phase pole line on the South Service Road. This includes conversion of an existing radial 8.32 KV section of F2 feeder fed from Greenlane D.S. to 27.6 KV on Victoria Avenue north of the Q.E.W. A good portion of the line on Victoria Ave had been previously re-built to 27.6KV insulation levels with dual voltage equipment.

SR1

12-M-6 Replacement—Simcoe St --Buckley Ave—Armoury St Area.

2013 Actual Cost	**$538,747**	**Project 2013-0005**
2014 Budgeted Cost	**<u>$372,631</u>**	
Total	**<u>$911,378</u>**	

The project scope involves the replacement of a PILCDSTA underground primary cable installed in 1961 with a 50' wood pole line supporting a 556kcmil 3 phase tree conductor. The area of rebuild is on Simcoe St. from Buckley Ave to Palmer Ave, and St Lawrence Ave from Armoury St to Simcoe St. The pole line will be constructed in the same alignment as the existing 2.4KV single phase pole line currently in service. The project eliminates the aging cable, which has posed reliability issues due to splice failures, and provides immediate voltage conversion opportunities of several lateral feeds from the existing pole line. It also provides a source for future voltage conversion of Station #3 & Station #6 loads.

SR2

Dorchester Rd. — Garden Street to McMillan Drive

2013 Actual Cost	**$198,807**	**Project 2013-0011**
2014 Budgeted Cost	**<u>$362,018</u>**	
Total	**<u>$560,825</u>**	

Project scope involves replacement of 1.5km of existing overhead single circuit 5kV line (F222) with a 15kV single circuit 3-phase line (KM4) on 50' poles on Dorchester Rd. between Garden St & McMillan Dr. The poles will maintain the same alignment as the existing 4.16kV pole line currently in service. System benefits include the replacement of aging equipment, improved equipment clearances, additional ties between Murray T.S and Kalar T.S. and the reduction of load on Municipal Substation #22 with conversion of some laterals to the new supply.

SR3

High Street—Dorchester Rd. to Drummond Station #10

2013 Actual Cost $633,880 Project 2013-0008

Project scope involves replacement of 1.2km of existing overhead double circuit 4.16kV line (F101 and F102) with a 15 KV single circuit 3-phase line (3M51) on 50' poles between Dorchester Rd. and Leonard Ave. It includes an underground structure between High St. and Station #10. The new poles will maintain the alignment of the existing 4.16KV poles. The construction facilitates conversion of laterals rebuilt on the side streets within recent years. System benefits include replacement of aging equipment, improved equipment clearances. It also contributes to load reduction on Municipal Substations #10 & #22 with conversion of the laterals.

SR20

Required overhead line rebuild of deteriorated facilities identified by the pole condition survey.

Murray/Culp

2013 Actual Cost $712,700 Project 2013-0007

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2013 this program targets approximately the remainder of 5 kilometers of urban distribution line requiring 150 pole changes, the installation of new single phase primary and secondary circuits, 30 distribution transformer replacements and results in upgraded supply to about 400 residential customers.

SR21

Overhead to Underground Primary Conversion-Beacon Inn --Jordan.

2013 Actual Cost	**$259,593**	**Project 2013-0021**

The project scope involves the installation of approximately 250 meters of 2/0 underground primary cable within a duct structure placed by Cogeco during a 2011 reconstruction project. Also included, is the construction of 8-spans of 3 phase and 11-spans of 3 phase pole line, which allows NPEI to deal with an inaccessible overhead pole line on private property for which easement documentation is unavailable.

SR22

Underground Primary Extension-Weightman Bridge Chippawa.

2013 Actual Cost	**$113,001**	**Project 2013-0003**
2014 Budgeted Cost	**$701,810**	
Total	**$814,811**	

The project scope involves the installation of approximately 230 meters of 600kcMIL underground primary cable within an existing duct structure placed during the bridge reconstruction. Also included are the construction of two primary risers and a recloser installation to minimize feeder exposure for upstream commercial loads. The project allows NPEI to deal with two existing overhead crossings over the Welland River which are approaching end of life.

SR23

3-M-28 3-M-26 & 3-M-29 Feeder Replacement.

2014 Budgeted Cost	**$417,731**

The project scope involves the installation of 3-new manhole assemblies within the Municipal R.O.W. outside of Murray Transformer Station, including the replacement of existing directly buried feeder conductors within existing duct structures installed previously. New primary underground cable will be installed from the feeder breakers consisting of approximately 3.0 kilometers of 600 kcMIL conductor and terminations at 3 new proposed metering units. Benefits include provisions for resolution of the expired wholesale metering points on feeders (metering is under a separate project) and improved supply reliability to the tourist core with the introduction of new supply cables.

SR24

Crawford Street--Thorold Stone South to Sheldon

2014 Budgeted Cost	**$516,557**
2015 Budgeted Cost	**$282,324**
Total	**$798,880**

This rebuild project targets 1.38 kilometers of urban distribution line installed in 1953. The scope includes 50 pole changes, new single (880 meters) and three phase (500 meters) primary and secondary (1790 meters) circuits. The scope also includes 10 distribution transformer replacements resulting in the upgraded supply to about 122 residential customers in the area bounded by Drummond Rd., Portage Road, Sheldon St., St James St., Longhurst Ave, Elberta ave. and Crawford St. System benefits include replacement of aging equipment, future voltage conversions opportunities, and improved equipment clearance.

SR56

Frederica Street Rebuild

2015 Budgeted Cost $676,144

Project scope involves the replacement of 1.1 KM. of existing 2/0 overhead 4.16 KV (F-104) primary line installed in 1955 with 16-new 45' wood poles & utilizing 12-existing poles replaced previously and re-conductor the existing with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 4-new transformers, install 1.1KM of secondary buss, and transfer of 55 services to the new buss. Benefits include the final stage of reconstruction to eliminate Municipal Sub-station Stn. #22 constructed in 1969, targeted for decommissioning, the provision for immediate voltage conversion opportunities of several existing lateral feeds, improved system losses, improved equipment clearances.

SR25

Fallsview Boulevard--Ferry Street to Robinson St

2014 Budgeted Cost $332,173

Project scope involves replacement of 0.5 kilometers of existing overhead 5kV line (F72) with an underground 15kV single circuit 3-phase line (3M54) between Robinson St and Ferry St pending a City of Niagara Falls Road Reconstruction Project. The Road reconstruction includes widening to 4-lanes and re-alignment of the intersection at Ferry St reducing the available boulevard required for construction of a pole line. The source will be a spare position in existing switching station #33 to a pole line north of Ferry Street. System benefits include replacement of aging equipment, conversion of an underground transformer vault at the Fairway Inn, and load reduction on the Municipal Substation #7 by conversion of the lateral to 15KV.

SR26

Jordan Road—Red Maple to the QEW

2014 Budgeted Cost $397,516

The project scope involves the rebuild of existing 3-phase 8.32kV primary line, in place, constructed to 27.6KV standards for approx 2.0km. This includes the installation of 34-new 45' poles, transfer of existing primary conductors, and installation of 2.0km of new neutral. The project is driven by the pole inspection program which has identified a large number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and provisions for future conversion to 27.6KV of the feeders supplied by Jordan D.S. for its eventual de-commissioning.

SR26

Jordan Phase II

2015 Budgeted Cost $449,324

The Project Scope involves the rebuild of existing 3-phase 8320 Volt primary line, in place, constructed to 27.6KV standards for approx 2.0 KM involving the installation of 34-new 45' Bell Telephone Owned poles, transfer of existing primary conductors, and installation of 2.0km of new neutral. The project was driven by the pole inspection program which has identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and provisions for future conversion to 27.6KV of the feeders supplied by Jordan M.S. for its eventual de-commissioning.

SR27

Wholesale Meter Replacement

2014 Budgeted Cost $300,000

Murray Y Bus metering is at end of life and no longer meets IESO standards for wholesale settlement. Project scope includes installation, connection and commissioning of 5 pad-mounted 15kV - 600A metering units. Scheduling of construction will be coordinated with project 2014-0009 (3-M-28, 3-M-26 & 3-M-29 Feeder Replacement).

SR28

Overhead to Underground Primary Conversion-Rolling Acres Subdivision Phase I

2014 Budgeted Cost	**$768,694**
2015 Budgeted Cost	**$570,500**
Total	**$1,339,194**

Phase I project scope involves the relocation of primary facilities currently situated on an inaccessible rear lot pole line within private property. Easement documentation is available for this line. Directional boring will be used to install 2.1km of primary duct to 7 pad-mounted transformers placed on precast pads within the road allowance. Secondary laterals will be directionally bored back to the rear lot easements in order to source the 106 individual house services currently fed underground from existing junction boxes mounted on the poles. The streets included within this Phase include Oxford, Wiltshire, Valour, Yale, Harvard, Varsity, McGill, & Eton. The current equipment was installed in 1959 and tree growth, pool, shed and fencing installations, have made the line difficult to maintain and service. 15KV rated equipment will be installed for future voltage conversion, once all the phases have been completed.

SR29

Overhead line rebuilds of facilities identified by the Pole Inspection Survey.

Dorchester/Lundys/Coach/Clare/Brookfield/Barker

2014 Budgeted Cost $516,513

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2014 this program targets 1.7 kilometers of urban distribution line installed in 1960, including 58 pole changes, new single phase primary and secondary circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 125 residential customers in the area bounded by Dorchester Rd., Lundy's Lane, Coach Drive, Clare Crescent, Brookfield Avenue & Barker Street.

This multi-year project focuses on commencement of rebuild in the area surrounding Station 22.

SR30

System Sustainment Allowance.

2010 Actual Cost	**$1,008,971**
2011 Actual Cost	**$451,575**
2012 Actual Cost	**$525,207**
2013 Actual Cost	**$670,727**
2014 Budgeted Cost	**$400,000**
2015 Budgeted Cost	**$680,000**
Total	**$3,736,480**

Sustainments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

SR31

Replacement of Poles identified with limited Structural Integrity.

2010 Actual Cost	**$788,664**
2011 Actual Cost	**$826,302**
2012 Actual Cost	**$862,338**
2013 Actual Cost	**$859,298**
2014 Budgeted Cost	**$778,702**
2015 Budgeted Cost	**$431,729**
Total	**$4,547,032**

Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. Steel and concrete poles are visually inspected based on the requirements of the DSC.

The 2014 Niagara test area is bounded in the South by Thorold Stone Road, West to Thorold Town Line, North to Mountain Road, and East to Stanley Ave/Whirlpool Road. The Western service territory testing area is bounded by Lake Ontario to the North, south to King Street excluding Beamsville, East to Ninth Street, and West to Thirty Road.

Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.

The 2015 Niagara test area is bounded in the West by the City Limits/Thorold Town Line Rd., South to the Welland River, East to Stanley Ave, North to Hwy #420/Beaverdams Road and includes 3693 poles total. The Western Service Territory test area is bounded by Mud Street to the north, south to Twenty Road, east to Walker Road, west to South Grimsby Road 20 and includes 3157 poles.

SR32

Replacement of Submersibles & Kiosks with EFD switches and posi-tects.

2010 Actual Cost	**$501,362**
2011 Actual Cost	**$508,036**
2012 Actual Cost	**$705,374**
2013 Actual Cost	**$643,270**
2014 Budgeted Cost	**$624,457**
2015 Budgeted Cost	**$647,029**
Total	**$3,629,528**

The Kiosk replacement program is an integral part of our underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved.

In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. The locations are prioritized by the results of a Conditional Assessment Survey completed in 2013, which will be repeated on a 5-year cycle as required.

57-Units remaining on the 15kV System and 8 were converted in 2013. 74-Units remaining on the 5kV System and 4 were converted in 2013. 5-Submersible units were also converted to pad-mounts with only 4 remaining on the system

For 2014 and 2015, the plan is to replace an average of 10 units per year.

SR33

Replacement of Transformers with >50PPM PCB Content.

2013 Actual Cost	**$125,175**	**Project 2013-2011**
2014 Budgeted Cost	**$566,479**	
2015 Budgeted Cost	**$495,104**	
Total	**$1,186,758**	

The second phase of the three year transformer testing program has been completed within the West service territory resulting in the requirement to replace units identified as having over the legislated limit for PCB content. The program will track these change-outs which will likely include the replacement of the pole supporting the unit with associated transfers, removals and disposal costs. The final round of testing will begin in May of 2014. As per NPEI's

Distribution System Plan and Appendix 2-AA, the replacement of these transformers will be complete by the end of 2015.

SR57

NWTS Metering Replacement

2015 Budgeted Cost $289,605

Due to several failures of the existing 230 KV primary metering units monitoring the DESN at the Niagara West Transformer Station, NPEI has identified a need for the replacement of the 2 Primary Metering units with 4-low voltage feeder metering units, minimizing system wide outages which occurred during the metering failures, providing improved reliability and accuracy of billing and settlement.

SR60

Willodell Rebuild

2015 Budgeted Cost $310,710

Project scope involves replacement/relocation of 1.5 KM. of rural overhead 2.4 KV (RECL-2) off-road primary line with an overhead 15 KV class single phase line relocated within the Willodell Road Allowance between Gonder Rd & Koabel Rd. Installation of 27-new 45' wood poles, 6-25KVA transformer and transfer 8-existing services. System benefits include the replacement of aging equipment originally installed in 1949, constructed on private property, by Ontario Hydro, without registered easements in favor of the Utility, relocation of inaccessible infrastructure, future capability of conversion to 15KV with clearance sufficient to construct 3-phase if required, improved reliability and reduced response time due to improved equipment access.

SR59

Willoughby Drive – Cattell Drive to Weinbrenner Road

2015 Budgeted Cost $383,293

Project scope involves the replacement of 0.7 KM. of urban overhead 13.8 KV primary line installed in 1969 with 21-new 45' wood poles framed for 3-phase & 4-new 40' wood poles framed for single phase and re-conductor the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 5-single phase & 1-three phase transformer to replace existing, install 1.1KM of secondary buss, and transfer of 30 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement of supply to a sensitive load (large Senior Care Facility).

SR58

Willoughby Drive – Main Street to Cattell Drive

2015 Budgeted Cost $372,191

Project scope involves the replacement of 1.2 KM. of urban overhead 13.8 KV primary line installed in 1960 with 17-new 45' wood poles framed for 3-phase, 10-new 40' wood poles framed for single phase and re-conductor the existing 3/0 Lum with 556 MCM 3-phase main circuit, constructed in the same alignment as the existing pole line, install 7-single phase & 1-three phase transformer to replace existing, install 1.1KM of secondary buss, and transfer of 34 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the main distribution line.

<u>System Service</u>

Smart Meters

2010 Actual Cost	**$4,175,010**
2013 Actual Cost	**$27,128**
2014 Budgeted Cost	**<u>$1,903,089</u>**
Total	**<u>$6,105,227</u>**

SS34

Pad-mounted Switchgear Replacements

2010 Actual Cost	**$461,327**
2011 Actual Cost	**$191,370**
2012 Actual Cost	**$313,737**
2013 Actual Cost	**$264,913**
2014 Budgeted Cost	**$110,057**
2015 Budgeted Cost	**<u>$250,002</u>**
Total	**<u>$1,591,405</u>**

Results from the underground equipment inspection program in 2008 and 2009 identified 17 switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

SS35

Cherry Avenue 27.6 KV Supply Extension.

2010 Actual Cost $179,386 Project 2010-0024

The project scope is extension of .75 km 3-Phase 8.32 kV supply from Yonge Street, on Cherry Avenue. This is to eliminate a deteriorated, inaccessible, overhead 8.32 kV circuit through the Twenty Valley Golf Course property. Many poles are identified for immediate replacement through the asset condition assessment. Equipment will be installed within the Road Allowance and secondary will be installed to supply the existing pump equipment. Upon completion, the line will be removed through the golf course.

SS36

Durham voltage conversion Phase 2.

2010 Actual Cost $364,430 Project 2010-0023

The final phase of this voltage conversion project will focus on the customers supplied on the periphery of the area supplied by the Durham 27.6 / 8.32 kV station. This facilitates a staged reduction for elimination of load supplied by this station. The station was constructed on a temporary basis years ago to deal with increasing loads and was not constructed in a manner that would provide for a long-term reliable source of power. By rebuilding and converting 8.32 kV customer loads along Durham Road, Greenlane Road and Mountainview Road, a reduction in loading will be realized on the station and additional 27.6 kV ties will be available to provide increased reliability in this area. This phase will achieve a complete load conversion and elimination of the station

SS37

Required overhead line rebuild of deteriorated facilities identified by the pole condition survey.

High Street Area

2010 Actual Cost $255,782 Project 2010-0002

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical

This project focuses on completion of rebuild in the High Street area. This is a multi-year project that commenced in 2008.

SS47

Oakwood Drive—Smart Centre Construction Conflicts

2010 Actual Cost $198,387 Project 2010-0008

Scope of work involves connection of the exiting highway crossing opposite Niagara Square to the new double circuit line on Oakwood Drive. The project will also incorporate the relocation of a section of off-road line, south of the construction limits to the boulevard, to improve access & facilitate road lighting. Construction is required due to construction conflicts with the

Smart Center road works, and system requirements for additional circuit intertie capabilities between Kalar M.T.S. and Murray T.S. The circuit interties improve feeder load balancing during contingencies.

SS50

K-M-6 & K-M-2 Extension--Montrose Road-McLeod to Canadian Drive

2011 Actual Cost $347,760 Project 2011-0003

Extension of a double circuit overhead line is required in the area due to increasing residential load growth and proposed Smart Centre Developments. The area is currently serviced by the 3M30 circuit and there is limited redundant supply in the area. The scope involves extension of the double circuit overhead line using Kalar M.T.S. feeders KM2 and KM6, from the existing dead-end at McLeod Road. The circuits will project south on Montrose Rd. to the existing highway crossing opposite Niagara Square. Construction is in conjunction with the relocation of the pole line on Oakwood Drive, due to road works for the Smart Centre currently under construction. Benefits include additional circuit inter-tie capabilities between Kalar & Murray Transformer Stations circuits for feeder load balancing and contingency options.

SS51

K-M-1 & K-M-5 Egress—Kalar M.T.S. to K-M-7 K-M-2 Pole Line in H.O.N.I. Transmission R.O.W.

2012 Actual Cost $169,041

This project is due to residential load growth and proposed developments within the area currently serviced by the Kalar KM7 and KM2 feeders. The project scope involves the construction of an 150M underground duct bank from the existing double circuit overhead line within the Hydro One transmission corridor to the 2-existing spare breaker positions at the

Kalar M.T.S. building. Benefits include additional circuit inter-tie capabilities between feeders egressing from Kalar & Murray Transformer Stations for feeder load relief, balancing, and contingency purposes.

SS53

King Street—27.6 K.V. Extension to Martin Rd.

2014 Budgeted Cost	**$112,554**
2015 Budgeted Cost	**$114,460**
Total	**$227,014**

The Project Scope involves the rebuild of existing 1-phase 16KV primary line west of Martin Ave to the 3-phase dead-end, in place, and constructed to 3-phase 27.6KV for approx 280 meters. Construction involves the installation of 8-new 45' poles, transfer of 1-primary riser, and installation of 165 m of new 3-phase from Rittenhouse Road to Martin Rd, and removal of 6-existing poles. Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

SS54

Robinson St. Allendale to Clarke UG Primary Extension

2010 Actual Cost	**$306,869**
2011 Actual Cost	**$733,072**
Total	**$1,039,941**

Due to increasing load growth and proposed development within the Fallsview Tourist/Commercial Core the introduction of an additional feeder into the area is required. The proposal would include the construction of a 600 meter long duct bank for extension of a 600 Amp 13,800 Volt distribution feeder using the Murray Station 3M54 from the existing double circuit pole line in the adjacent Hydro One Corridor. The 3M54 circuit will be directed into the manhole/switchgear assembly at Station #33 on Fallsview Blvd. The circuit will continue to a new manhole/switchgear assembly on Clarke Ave. This will also include replacement of the high voltage switchgear #48 at Old Stone Inn and modifications to the Budget Inn Stn. #120. Both switchgear units are nearing end of life based on asset condition assessment data. The Construction will provide load relief & alternate buss supply to loads currently supplied by the 3M29 Feeder.

SS62

Required overhead line rebuild of deteriorated facilities identified by the pole condition survey.

Culp from Main to Drummond

2010 Actual Cost	**$211,701**	**Project 2010-0007**

This project involves the installation of a 13.8kV 3-phase circuit in place of the existing single phase circuit in preparation for voltage conversion in the surrounding area of Culp St. The new 3-phase circuit will consist of tree cable installed on fiber glass brackets in order to minimize the effects of tree contact in the area. The new line will also present a 13.8kV source into Main Street to facilitate conversion of municipal station #8 loads in the future.

SS48

Kalar Road—Beaverdams Rd. to the NS&T ROW

2011 Actual Cost	**$385,308**
2012 Actual Cost	**$383,130**
Total	**$768,438**

The rebuild of 1600 meters of existing KM3 15 kV single circuit 3-phase pole line between Beaverdam's Rd. and the NS&T R.O.W with a double circuit concrete pole line. The pole line will be built on the West side of Kalar Road using the KM3 and KM7 feeders sourced from Kalar M.T.S. Construction is required in conjunction with circuit extensions completed for CNF road widening works between Lundy's Lane and Beaverdam's Rd. Construction is also required due to the age of existing plant, clearance issues, and requirement of an additional circuit for intertie capabilities to Stanley T.S. circuits 12M32 and 12M42 for feeder load balancing and contingency purposes.

Mobile 27.6KV/8.32KV Substation

2011 Actual Cost $214,555

Design, material procurement and construction of a 27.6kV - 8.32kV mobile substation. All of the distribution substations in the Lincoln / West Lincoln portion of NPEI's service territory are islanded and to not tie to other sources. These include:

Campden DS
Greenlane DS
Smithville DS
Jordan DS

The substation will consist of a 4MVA power transformer, high side dead-front switchgear, low side dead-front switch gear (2 feeders) all installed on a float deck trailer. The unit will be capable of being placed within the station confines of these 4 DS locations. The purpose is to reduce restoration time in a contingency from days to 2 hours.

Wi-max Project

2012 Actual Cost	**$332,339**
2013 Actual Cost	**$348,370**
2014 Budgeted Cost	**$227,500**
2015 Budgeted Cost	**$215,000**
Total	**$1,123,209**

With the coming into force of the *Green Energy and Economy Act, 2009,* several provisions were added to the OEB Act in relation to the development and implementation of a smart grid in Ontario. The Board now has a statutory objective to facilitate the implementation of a smart grid in Ontario, and it is a deemed condition of license for all electricity distributors and transmitters to plan for and make smart grid investments as directed by the Board.

On March 28, 2013, the Board issued *Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Applications – Consolidated Distribution Plan Filing Requirements.* Section 5.0.3.4 of the Chapter 5 Filing Requirements states:
"Under the renewed regulatory framework, smart grid development is expected to be integral to distribution system plans, a central focus of grid-enhancing innovation, and implemented on a coordinated regional basis to achieve economies of scope and scale."

In view of the above, NPEI began strategic investment into the development of a smart grid and is implementing a plan that consists of a three-pronged approach, involving:

1) The installation of backup DC power systems,
2) The installation of a wireless communications network, and
3) The upgrade of archaic electromechanical equipment with modern electronics.

The backup DC power systems and communications network constitute the backbone of the smart grid. Both fundamental components will enable the continued addition of modern electronics to the distribution system for the foreseeable future. The DC systems are required to power both the communications network and modern electronics. It will also provide an uninterrupted power source during system outages.

Each electronic device added to the distribution system represents an opportunity to improve power quality, efficiency, reliability, security and safety by:

- Enhancing monitoring, control and diagnostics functionality,
- Improving NPEI's ability to identify and respond to problems more quickly,
- Introducing system automation,
- Improving the quantity and quality of information available,
- Allowing greater flexibility in system configuration,
- Enabling the ability to implement condition-based maintenance,
- Establishing a communications platform capable of supporting real-time system modeling and analysis.

Added-value is achieved for the customer by:

- Improving operational efficiency,
- Reducing the duration and frequency of outages,
- Establishing a communications platform capable of supporting advanced secondary services,
- Establishing a communications platform capable of dealing with next-generation loads and substantial penetration of green energy, and
- Improving the availability and accuracy of information.

Advantages of using WiMax include:

- 4G technology allows for higher bandwidth and data throughput;
- WiMax is the best 4G fixed-point to multi-point radio system available to date;

- WiMax leverages Industry Canada's allocation of the 1800-1830 MHz frequency band reserved specifically for utilities;
- WiMax provides the backbone upon which a SCADA system can be implemented for real-time monitoring and control of critical assets.

In implementing its WiMax project, NPEI is collaborating with both McMaster University and Mohawk College. The collaboration with these educational institutions will give NPEI access to research and development in WiMax technology, which will benefit NPEI and its customers in deployment.

General Plant

Building

2010 Actual Cost	**$67,188**
2011 Actual Cost	**$121,779**
2012 Actual Cost	**$631,111**
2013 Actual Cost	**$1,912,395**
2014 Budgeted Cost	**$1,500,485**
2015 Budgeted Cost	**$44,000**
Total	**$4,276,958**

2010 Cost = $67,188

NPEI's building expenditures in 2010 include:

- The final costs of the new Service Centre in Smithville, which was substantially completed in 2009. 23K.
- A new roof on NPEI's Niagara Falls building. $22K.

2011 Cost = $121,779

NPEI's building expenditures in 2011 include:

- New energy efficient lighting fixtures in the Niagara Falls garage area. $72K.
- A concrete pad and outdoor racking for wire storage in Smithville. $37K.

<u>2012 Cost = $631,111</u>

NPEI's building expenditures in 2012 include:

- The steel pole bunks located in the Niagara Falls yard were installed in 1985. Due to weather and ground conditions these steel pole bunks have deteriorated and sunk into the ground and have become a hazard and pose a safety risk. In 2012, NPEI replaced these steel pole bunks with a precast concrete pole rack storage system. These new bunks are estimated to have a service life of 60 years. $131K.

- At the time, NPEI employed 31 management personnel. There were 25 offices combined between the two administration buildings. Desk space was being occupied at 100% capacity. Employees were working in the Quiet Room at the Niagara Falls facility. In 2012, NPEI completed a workspace optimization project in its Niagara Falls building to utilize the administration building's space more efficiently. This project resulted in the creation of 7 new offices and several new work stations in the old meter shop area. This area now houses NPEI's CDM, Human Resources, Corporate Communications and Purchasing departments. A new storage room for accounting records was also included in this project. 303K.

- Prior to 2012, NPEI's fleet vehicles in the Niagara Falls area were fueled from on-site tanks that were installed in 1988. Vehicles in the Smithville area were fueled from local gas stations, using a corporate gas card. In 2012, NPEI replaced the fuel tanks in Niagara Falls and installed fuel tanks in Smithville. The installations also include tracking and control systems. 120K.

2013 Cost = $1,912,395

NPEI's building expenditures in 2013 include:

- Due to the new commercial development on McLeod Road, traffic congestion has increased dramatically on Pin Oak Drive. Third party consultants were retained at the beginning of 2012 and a detailed review of the property was completed. The result of the review was to relocate the wire out of stores into a non-heated wire building with an overhead crane and a drive through access. Wire will only be handled once when received and once when issued and in both processes via an overhead crane. The new wire building is located directly behind stores in the yard. The building is 14,400 square feet and includes 6 bays for vehicle and equipment storage on both sides of the building. The total cost includes the foundations, gravel, overhead doors, electrical and mechanical components. Wire will be stored and issued in a safe and timely manner. $907K.

- High Mast Lighting of the yard options were reviewed extensively. Four, 70 feet high mast lighting structures with 8 luminaries each were included in the 2013 budget. The budget amount includes the foundations and electrical controls with dual mode illumination levels and automated control with motorized lowering devices for maintenance. $435K.

- Traffic congestion has increased dramatically on Pin Oak Drive with new streetlights being installed at the north end of Pin Oak. With this anticipated increase in the volume of traffic, there will be an added risk in moving NPEI's equipment in and out of the Niagara Falls service yard using the front driveway. With some upgrades to the rear driveway out to Kalar Road, some additional drainage installed along with an electric fence at the Kalar entrance NPEI can greatly reduce the hazard that this additional volume of traffic will bring in moving our fleet and equipment around on a day to day basis. Along with this would become the new entrance for shipping and receiving. Currently, NPEI has an access opportunity to Kalar Road and has budgeted for the construction of a new secure entrance for its operations and engineering departments to access the Niagara Falls service centre from Kalar Road versus Pin Oak Drive. In 2013, NPEI completed the necessary yard excavation in order that the new entrance may be paved in 2014. 533K.

<u>2014 Budgeted Cost = $1,500,485</u>

NPEI's budgeted building expenditures in 2014 include:

- The Niagara Falls stores area will be renovated. The new operations area and meter shop will be relocated to part of the current stores area. Approximately 8,000 square feet will house 5 offices, a Lead Hand area, the Operations Assistant workstation, a planning room, record storage room, mud room, locker room, washroom facilities, line tool storage area, maintenance area, and meter shop. The remaining 6,000 square feet of the existing space will be for the small stores area. $1,113K.

- The high mast lighting in the Niagara Falls yard will be completed. $198K.

- The new entrance from Kalar Road will be paved. $120K.

- 20 new parking spaces will be added to the south side of the Niagara Falls building. $70K.

<u>2015 Budgeted Cost = $44,000</u>

NPEI's Smithville service centre and administrative building was constructed in 2009. From 2012 to 2014, NPEI completed several renovations and workspace optimization projects in its Niagara Falls building and yard. Accordingly, NPEI does not expect to incur significant building expenditures during the 2015 to 2019 period. NPEI has budgeted a total of $220,000 in building costs for 2015 – 2019, including:

- Additional paving in Niagara Falls. $90K.
- Control room modification in Niagara Falls. $50K.
- New meeting rooms and office in Niagara Falls. $80K.

NPEI expects that its next rebasing after 2015 will be in 2020. Therefore, NPEI has included in this current Application one fifth of the anticipated building cost for 2015 – 2019: $220,000 / 5 = $44,000.

Computer Hardware

2010 Actual Cost	**$257,960**
2011 Actual Cost	**$247,812**
2012 Actual Cost	**$370,710**
2013 Actual Cost	**$274,903**
2014 Budgeted Cost	**$297,040**
2015 Budgeted Cost	**$240,248**
Total	**$1,688,673**

2010 Cost = $257,960

NPEI's hardware expenditures in 2010 include:

- Installation of mobile workstations in fleet vehicles. This provides NPEI's operations staff working in the field real-time access to many of NPEI's systems. 106K.
- New and replacement servers. $99K.

2011 Cost = $247,812

NPEI's hardware expenditures in 2011 include:

- Installation of mobile workstations in fleet vehicles. 63K.
- New and replacement servers. $146K.

2012 Cost = $370,710

The intent of the 2012 hardware and software budget is to continue business support as the technological infrastructure of Niagara Peninsula Energy continues to grow. With growth, it is necessary to protect our IT investments and ensure reliable and redundant systems. To accomplish this, the focus of the IT projects for 2012 is enhancements to support business initiatives, risk management to address assurance that the network is resilient and protected from external security threats, and disaster recovery planning.

As the technological infrastructure of Niagara Peninsula Energy grows, it is necessary to ensure that business continuity plans are in place and can be tested and ready to use. Traditionally, we have installed hardware and software with built in redundancy and backup processes. This will continue. In addition to this process, we will document a disaster recovery standard requirement policy and formalize a disaster recovery plan.

In 2012, the disaster recovery infrastructure will be completed, built and tested. Disaster Recovery will encompass physical and virtual backup and recovery processes, as well as, multiple off- site data storage and recovery. Smithville will be back up to Niagara Falls. If failure is within service territory, a "hot site" will be hosted through our Network support partner, Aegisys in Sudbury. This means that if we experience failure in Niagara Falls, we can recover from physical or virtual backup (dependent on source of data and essential business process.) If we fail in both Niagara Falls and Smithville, essential business processes can be provided through virtual web application via Aegisys. This will allow time to rebuild failed source.

Hardware investments in 2012 will satisfy requirements for: support to new business requirements, maintenance and replacement of outdated hardware, network infrastructure and growth, and disaster recovery planning.

New business initiatives requiring hardware include: Finance – Great Plains Timesheet application; Operations –source and implementation of SCADA; Building& Maintenance – Upgrade of Security System and Website workflow.

In 2012, an external audit will be completed to ensure that data and network infrastructure is sufficient.

Computer hardware additions in 2012 include:

- New and replacement servers. $242K.
- Network Switches. $23K.
- Access card system. $22K.
- Firewall. $22K.
- PCs, monitors and printers. $32K.

2013 Cost =$274,903

Spending of hardware will be managed with greater emphasis on network infrastructure and disaster recovery and new business requirements. The following outlines the projects/business need:

• Improved Network Infrastructure resulting from the purchase of load balancers for back up links, switches and servers; consultations on optimization and disaster recovery.

• Move to a hosted exchange server solution

• Upgrade of PC's and monitors due to age and use: 25 replacements will be completed in 2013 within Engineering, Billing, Customer Service, and Conservation. The upgrade will include upgrade to Windows and Office 2007.

• Workforce/Outage Management Ongoing Implementation, integration and support: we will be reviewing the use of iPad with ruggedized auto box versus a mobile ruggedized tablet for service order processing for moves and collections. This may result in cost savings from $2500.00 per tablet versus $1000.00 per tablet.

• Update of Phone system integration and support to include the ability of making payment via the IVR (automated voice solution); the solution would result in one call being directed to third party payment provider offering credit card and debit/interac payment methods. Professional Services will be utilized to provide recommendation on update to existing IVR hardware.

• Professional Services required to improve redundancy with the Mitel telecommunications solution

• Enterprise solutions such as update and implementation of web based tools linked to the website including increased functionality of the web based tool Mcare integrated with GIS tools (in-service); this encompasses automation of workflows between customer, metering, engineering, and billing providing efficiencies, improved customer service, and long term cost savings. Workflows impacted include New Service, Meter Changes, Reporting a problem, and Outage Management.

• Wear and malfunction of handheld meter reading devices.

• Improve Engineering efficiencies in the field through the use of a HD Video Camera.

• Support of SCADA solution

• Disaster Recovery and Business Continuity: In 2013, continued focus on building infrastructure to secure data and systems, while preparing for a failure. In the last two years, we have designed and build upon disaster recovery measures and infrastructure. The disaster recovery plan encompasses a multi-tier solution to ensure all core systems are recoverable with minimal downtime to the business. Each core system implemented has embedded backup procedures to tape, backup server, and off-site recovery. We are working on a solution that encompasses internal backup recovery (tape/redundant server) as well as external offsite recovery utilizing a third party and virtual management strategy.

• Professional Services and access entry points to provide redundant internet/WAN fibre services. The internet/communications link between Niagara Falls and Smithville needs to be reviewed to ensure that we have redundancy or back up in the event of failure. In discussion with Niagara Regional Broadband, there is minimally 9 months as they refresh their own network, for them to be able to provide a redundant or even a dedicated service for SCADA data. The capital expenditure required to ensure that we have redundancy either through additional service access points, additional internet links, or access to alternate Point of Presence (for example, access to Niagara Falls point, as well as, St. Catharines) is substantial due to the unknowns at this time regarding the Niagara Regional Broadband refresh activities. We have estimated based on the current infrastructure and information being provided to us.

• Address risk management through security audits of all network infrastructure.

Computer hardware additions in 2013 include:

- New and replacement servers. $45K.
- Back-up Internet Link. $143K.
- PCs, laptops, notebooks, monitors and printers. $46K.

2014

The Information Technology capital expenditures for 2014 continue to ensure that business goals are aligned to technological solutions. NPEI's network infrastructure will be optimized allowing for improved business uptime and resiliency.

The hardware and software requirements within each area allow for the following goals to be met:

• Effective and efficient business processes
• Support of risk and compliance management processes and methodology (enabling a methodology, not defining)
• Integrated, reliable, enterprise solutions
• Network integration and security
• Embedded business continuity practices, and continued update and testing of a Disaster Recovery Plan

Spending of hardware will be managed with greater emphasis on network infrastructure and disaster recovery and new business requirements.

The following outlines the proposed 2014 costs. Costs are related to the following projects/business need:

• Improved Network Infrastructure resulting from the purchase of backup switches and servers; consultations on optimization and disaster recovery.

• Move to a hosted exchange server solution (incomplete in 2013)

• Upgrade of PC's and monitors due to age and use: 50 replacements will be completed in 2014 within Operations (purchasing, stores, metering (including meter shop test board PC upgrade and test board firmware) lead hand offices) Human Resources, Accounting, Executive Office, Billing, Customer Service, Business Application Support. The upgrade will include upgrade to Windows and Office 2007.

• Hardware server requirements in conjunction with the implementation of a bar coding software solution in the supply chain management processes

• Workforce/Outage Management Ongoing Implementation, integration and support: we will continue the pilot of replacement of aging mobile ruggedized tablets.

• Update of cell phones, current phones 3 year term ends in June 2014

• Continue the upgrade of enterprise solutions such as update and implementation of web based tools linked to the website including increased functionality of the web based tool M-care integrated with GIS tools (in-Service); this encompasses automation of workflows between customer, metering, engineering, and billing providing efficiencies, improved customer service, and long term cost savings.

Workflows impacted include New Service, Meter Changes, Reporting a problem, and Outage Management.

• Wear and malfunction of handheld meter reading devices, headsets, and signature pad when needed.

• Disaster Recovery and Business Continuity: In 2014, we will continue focus on building infrastructure to secure data and systems, while preparing for a failure. In the last three years, we have designed and build upon disaster recovery measures and infrastructure. The disaster recovery plan encompasses a multi-tier solution to ensure all core systems are recoverable with minimal downtime to the business. Each core system implemented has embedded backup procedures to tape, backup server, and off-site recovery. We are working on a solution that encompasses internal backup recovery (tape/redundant server) as well as external offsite recovery utilizing a third party and virtual management.

• Address risk management through security audits of all network infrastructure.

Computer hardware additions budgeted for 2014 include:

- New and replacement servers. $128K.
- Network switches. $24K.
- Cell phones. $23K.
- PCs, laptops, notebooks, monitors and printers. $81K.

<u>2015</u>

Spending of hardware will be managed with continued emphasis on new business requirements, network infrastructure and disaster recovery. Purchases of hardware are directly related to building on resiliency and redundancy achieving measurable results meeting the needs of software to be implemented and improved business practices.

Costs are related to the following projects/business need. If hardware or equipment is scheduled to be purchased based on renewal or replacement, the year to replace is based on 5 year lifecycle specific to hardware/equipment use.

• Barcoding equipment providing operational efficiencies of inventory;

• Cell phones renewal and replacement; cell phones are integral part of communication strategy for on-call, in-field and management staff;

• Mail machines (equipment) for processing of customer outgoing communications;

• Maintenance and replacement of legacy Radix handhelds (equipment) to read few conventional meters. New purchases of meter reading handhelds are not scheduled due to smart meters; the purchase of handhelds is based on necessary replacement due to repair to support conventional meters during implementation of MIST meters.

• LCD projectors renewal for use in Boardrooms and meeting rooms;

• Improved Network Infrastructure resulting in purchase of switches and servers; taking into account growth and expansion of data requirements. Server purchases include renewal based on age, purchase of server for new business requirements specific to backup strategy, upgrade of financial software (Great Plains), disaster recovery build, WIMAX and SCADA.

• Workforce/Outage Management Ongoing Implementation, integration and support (including migration server)

• Upgrade of PC's, laptops, tablets, and printers due to age and use. Laptops and tablets are used in the field by management, operations and metering staff. The use of laptops and tablets in the field provide operational efficiencies in response time and accuracy of information.

• Purchase of required office phones, renewal and extension of life of phone system integration and support.

One method of maximizing IT investment is continual monitoring of hardware, building redundancy on core systems. This is a continual process improving network infrastructure.

This is accomplished in the hardware expenditures of additional network switches, update of proxy, wireless access points, improved backup solutions, along with the creation and implementation, including testing of the Disaster Recovery Plan which would document the process, policies and procedures of restoring operations critical to the resumption of business including regaining access to data (hardware, software, records), communications (incoming/outgoing telecommunications), and workspace.

Key business processes including Outage Management, Phone system added functionality of Integrated Voice Recognition, as well as, integration into the Outage Management tools and need for redundancy outline the business need for additional hardware such as servers, hardware relative to phones.

In order to maintain tools that allow for efficient processes, we cycle through phones, PCs and Printers based on age and need.

NPEI has budgeted a total of $1,201,240 in hardware costs for 2015 – 2019, including:

- New and Replacement Servers. $505K.
- Network Equipment. $102K.
- Barcoding Equipment. $25K.
- Cell Phones. $25K.
- PCs, laptops, notebooks, monitors and printers. $358K.
- Phone System. $149K.
- Other Equipment. $37K.

NPEI expects that its next rebasing after 2015 will be in 2020. Therefore, NPEI has included in this current Application one fifth of the anticipated hardware cost for 2015 – 2019: $1,201,240 / 5 = $240,248.

Computer Software

2010 Actual Cost	**$250,022**
2011 Actual Cost	**$193,505**
2012 Actual Cost	**$213,431**
2013 Actual Cost	**$114,742**
2014 Budgeted Cost	**$498,710**
2015 Budgeted Cost	**$368,740**
Total	**$1,639,150**

2010 Cost = $250,022

NPEI's software expenditures in 2010 include:

- Workforce/Outage Management – This software provides for recording and reporting of all work force tasks, as well as, details of an outage. It allows for the efficiency and reliability of reporting to regulatory agencies, as well as, efficiencies in management of resources required to complete tasks and oversee an outage. This solution accommodates our growth where current manual or other software has become too labour intensive in the security, scalability; costly to manage (does not accommodate changes in technology.) Workforce/Outage management compliments pilot field projects/exercises where ruggedized laptops/PCs are in the field. This solution will contribute to the provision of effective and efficient processes improving customer service. $85K.

- Harris Northstar CIS. $83K.
- Phone system software. $22K.
- Microsoft Dynamics GP. $22K.

2011 Cost = $193,505

NPEI's software expenditures in 2011 include:

- Workforce/Outage Management. $47K.
- Harris Northstar CIS. $92K.
- Phone system software. $10K.
- Apollo Workflow. $15K.

2012 Cost = $213,431

Software investment in 2012 is to meet new business initiatives including:

Operations – source and implementation of SCADA; Website work flow; and Disaster Recovery.

Website updates include additional forms, employee portal, and Customer Connect (upgrade and enhancement to current e-care web presentment.) This software will enable text messaging and instant messaging/emails to reach our customers.

Customer Connect tool can be used to encourage and compliment conservation initiatives, and reach customers to inform of outages, rate and policy changes, other customer service messages. Customer Connect is user friendly and interactive for our customers providing additional views of consumption and how the customer is using their energy.

NPEI's software expenditures in 2012 include:

- VM Ware $46K.
- Harris Northstar CIS. $67K.
- Apollo Workflow. $45K.
- Disaster Recovery software. $39K.

<u>2013 Cost = $114,742</u>

Software required for business process improvement projects and new requirements, which promote efficiency and reliability including the following.

• Integration between operations sub-systems, m-care and in-service to the CIS to improve customer relationship management

• Incorporate automation platform within the CIS to automate workflows and build upon business analytics used in decision making.

• Update current daily, monthly, quarterly reports from Cognos 7 format to Cognos 8 format, leveraging improved functionality from a desktop automated tool

• Address risk management through security audits of all network infrastructure including web applications

• Support of SCADA solution

• Update of workforce/outage management tools including the review and capability of the use of the iPad in the field

• GTech designer seat license/licensing manager

• Visio licenses required in Engineering and Business Application support

• Enhanced backup solution promoting redundancy and business continuity

• Update of Payment vendor to improve the payment options to our customer to include credit card payment without limit of payment with decreased customer fee, and option of using debit/interac card

• Continued support of an effective enterprise solution having the following characteristics:

• Security – information is secured and has access control

• Scalable – accommodates growth

• Cost – value for money

• Manageable – provides the ability to manage implementation including version control

• Portable – accommodates changes in technology.

NPEI's software expenditures in 2013 include:

- Harris Northstar CIS. $9K.
- Apollo Workflow. $57K.
- Engineering Ground Grid software. $9K.

<u>2014 Budgeted Cost = $498,710</u>

Software required for business process improvement projects and new requirements, which promote efficiency and reliability including the following:

• Great Plains 2013 upgrade and programming of new reports

• Optimization of stores and inventory management through implementation of bar code software solution

• Continue the integration between operations sub-systems, m-care and in-service to the CIS to improve customer relationship management (Update of workforce/outage management tools including the review and capability of the use of the other mobilized ruggedized tablets in the field.)

• Continue to incorporate automation platform within the CIS and Apollo to automate workflows and build upon business analytics used in decision making.

• Continue to update current daily, monthly, quarterly reports from Cognos 7 format to Cognos 8 format, leveraging improved functionality from a desktop automated tool

• Continue to incorporate workflow tools through the use of File Nexus in Human Resources, Engineering, and Conservation

• Address risk management through security audits of all network infrastructure including web applications

• Continue with solution of an enhanced backup solution promoting redundancy and business continuity

In review of the business requirements put forth and determination of what software is considered as part of the capital budget, key areas are reviewed. Customer engagement is of high importance.

Hardware and software solutions proposed allow for the following goals to be met:

• Effective and Efficient Business Processes enabling our business units to meet customer need and preference.

• Support of risk and compliance management processes

• Integrated, reliable, enterprise solutions: key drivers in determination of how we enable home energy management systems, making customer information available.

• Network Integration and Security: ensuring customer data is secured; however, available within a third party or web base/ mobile application. Appropriate cyber security and privacy standards must be met.

• Embedded business continuity practice: assurance of reliability

NPEI remains customer focused. Through technology, customer service surveys, customer feedback on-line forums, NPEI is prepared to undertake activities that will allow us to understand customer's preferences and to address these preferences. Whether it is data access, support of distributed generation through streamlined processes, online application support or ease of access of customer consumption data and generation, information technology investments will allow NPEI to provide information and education to customers. Customers will be able to make decisions affecting their electricity costs with the access to real time data and behind the meter services and applications. NPEI itself will have opportunities for operational efficiencies through the use of data analytic tools and automated platforms.

NPEI's software expenditures budgeted for 2014 include:

- Barcoding Software. $50K.
- File Nexus conversion. $50K.
- Disaster Recovery software. $50K.
- Backup and UPS upgrade. $47K.
- Microsoft Dynamics GP. $40K.
- Malware Protection. $40K.
- Automation Platform. $25K.
- Apollo Workflow. $25K.
- Cognos Reports. $25K.
- Exchange Migration $25K.
- Bill Presentment changes. $24K.
- Professional / Programming fees. $60K.

<u>2015 Budgeted Cost = $368,740</u>

Software required for business process improvement projects and new requirements, which promote efficiency and reliability including the following. The following projects are categorized by department.

- All departments: Adobe Read/Write and Visio licenses
- All departments: Update of Windows operating system
- All departments: Microsoft developer network
- Finance: Great Plains upgrade and reports
- Finance: Timesheets

- G&A&Ops: Optimization of stores and inventory management through implementation of Accellos bar code customization and software
- Billing: Upgrade of CIS 6.x
- Billing and Engineering: Continue the integration between operations sub-systems, m-care and inservice to the CIS to improve customer relationship management (Update of workforce/outage management tools including the review and capability of the use of the other mobilized ruggedized tablets in the field)
- Billing and Customer Service: Continue to incorporate automation platform within the CIS to automate workflows and build upon business analytics used in decision making.
- Billing and Customer Service: : Continue to update current daily, monthly, quarterly reports from Cognos 7 format to Cognos 8 format, leveraging improved functionality from a desktop automated tool
- Customer Service: Telephony updates to address outage messages (being able to automate response to customers at time of outages, providing timely up to date information to the customer) These updates can also be used to add efficiencies to collection calls as well as time in queue: Alertworks
- Continue to incorporate workflow tools through the use of File Nexus in Human Resources, Engineering, and Conservation
- Address risk management through security audits of all network infrastructure including web applications
- Engineering: Support of Rugged.com/WIMAX and SCADA solution
- Customer Service and Conservation: Website improvements, Mobile GO payment application
- Continue with solution of an enhanced backup solution promoting redundancy and business continuity
- Continued support of an effective enterprise solution that will have the following characteristics:
- Security – information is secured and has access control
- Scalable – accommodates growth
- Cost – value for money
- Manageable – provides the ability to manage implementation including version control

- Portable – accommodates changes in technology.

NPEI has budgeted a total of $1,843,702 in software costs for 2015 – 2019, including:

- Programming / Professional Fees. $300K.
- Harris Northstar CIS. $150K.
- Workforce/Outage Management. $290K.
- SCADA system. $140K.
- Barcoding software. $100K.
- Oracle Licenses. $80K.
- Fleet vehicle software. $75K.
- Microsoft Dynamics GP. $75K.
- Microsoft Windows / Office licenses. $72K.
- Apollo Workflow. $50K.
- File Nexus. $50K.
- Website improvements. $50K.
- Disaster Recovery. $50K.

NPEI expects that its next rebasing after 2015 will be in 2020. Therefore, NPEI has included in this current Application one fifth of the anticipated hardware cost for 2015 – 2019: $1,843,702 / 5 = $368,740.

General Equipment

This category includes office furniture and equipment, stores equipment, tools, shop and garage equipment, measurement equipment, communications equipment and miscellaneous equipment.

2010 Actual Cost	**$176,811**
2011 Actual Cost	**$175,156**
2012 Actual Cost	**$244,851**
2013 Actual Cost	**$265,585**
2014 Budgeted Cost	**$299,000**
2015 Budgeted Cost	**$95,627**
Total	**$1,257,029**

2010 Cost = $176,811

NPEI's general equipment expenditures in 2010 include:

- Plotter. $20K.
- Cheque Encoder. $5K.
- Forklift and charger. $19K.
- Stores racking. $7K.
- Line hoses. $22K.
- Polyflex rope. $20K.
- Radios. $9K.
- Defibrillators. $5K.

2011 Cost = $175,156

NPEI's general equipment expenditures in 2011 include:

- Photocopiers. $36K.
- Office furniture. $16K.
- Paging system. $8K.
- Stores equipment. $10K.
- Hoist upgrade. $19K.
- Tools for line trucks. $11K.

2012 Cost = $244,851

NPEI's general equipment expenditures in 2012 include:

- Office Furniture, mainly relating to the Workspace Optimization project. $91K.
- Photocopiers. $18K.
- Tools for line trucks. $46K.
- Arc Reflection system. $30K.
- Manhole excavation equipment. $13K.
- Portable Service Transformer. $10K.
- Skid Resistant Mats. $9K.
- Defibrillators. $8K.

<u>2013 Cost = $265,585</u>

NPEI's general equipment expenditures in 2013 include:

- Equipment for new wire building. $141K.
- New entrance gate. $22K.
- Office furniture. $6K.
- Tools for line trucks. $22K.
- Traffic signs. $6K
- Grounds. $7K.

<u>2014 Budgeted cost = $299,000</u>

Office furniture, photocopier, security cameras and hardware for access to the new operations, meter shop and stores areas are included in the 2014 budget proposal. Ergonomic office equipment and five new defibrillators are proposed in the 2014 budget to maintain our commitment to health, wellness and safety. Additional security cameras to be installed at various locations have also been proposed in the 2014 budget.

New inventory racks for the Niagara Falls stores have been included in the budget for 2014. The current racking is over 30 years old.

NPEI's general equipment expenditures budgeted for 2014 include:

- Office furniture for new operations area. $70K.
- Other office furniture. $9K.
- Photocopier. $20K.
- Security cameras. $36K.
- Defibrillators. $13K
- Inventory Racking. $75K.
- Tools for line trucks. $10K.

2015

NPEI has budgeted a total of $478,133 in general equipment costs for 2015 – 2019, including:

- Office furniture. $45K.
- Photocopiers. $36K.
- Control Room workstation and table. $10K.
- Furniture for additional meeting room and 2 offices. $18K.
- Phasing sticks. $13K.
- Hydraulic Drills. $27K.
- Fibre Insulating Cover Ups. $15K.
- Gator Crimping Press. $13K.
- Tools for new line trucks. $37K.
- Miscellaneous general equipment. $55K.
- Miscellaneous replacement tools. $186K.

NPEI expects that its next rebasing after 2015 will be in 2020. Therefore, NPEI has included in this current Application one fifth of the anticipated general equipment cost for 2015 – 2019: $478,133 / 5 = $95,627.

Vehicles

2010 Actual Cost	**$869,037**
2011 Actual Cost	**$541,643**
2012 Actual Cost	**$1,160,649**
2013 Actual Cost	**$1,329,696**
2014 Budgeted Cost	**$672,000**
2015 Budgeted Cost	**$698,878**
Total	**$5,271,903**

2010 Cost = $869,037

NPEI's vehicle expenditures in 2010 include:

- Ford 4x4 pick-up truck. $39K.
- 46' Material Handling Aerial Manlift and fiberglass body. $195K.
- 47' Radial Boom Derrick and fiberglass body. $205K.
- Off-road track vehicle. $426K.

The Aerial Manlift was installed on a 2010 International 7400 chassis that was purchased in 2009. The RBD was installed on a 2010 Freightliner M2 chassis that was purchased in 2009.

The track vehicle is an off-road capable line vehicle with an aerial bucket and boom derrick configuration to facilitate off road (inaccessible) area access for pole replacement purposes. Evaluation of the pole location date through GIS system inquiry indicates that over 1,300 poles within NPEI's distribution system in the Lincoln and West Lincoln areas are inaccessible to our line truck fleet. Historically, the condition of these poles has not been evaluated to determine the risk they present to the utility if and when they fail. While the ideal solution to this inaccessible distribution plant would be relocation to the road allowance, it is not economically feasible and cannot be accomplished within a reasonable scope of time that would permit an approach to relocation only. Inaccessible poles, identified with limited structural integrity must be addressed within the pole replacement program to ensure the continuation of safe and reliable electricity distribution in these rural areas.

To date, off road equipment has been acquired through local private contractors to replace damages poles during contingency periods. The process has been mostly reactionary in nature, repairing poles and lines that have failed during severe weather events, resulting in extended customer outages and increased public hazards. There is no guarantee that private equipment will be available for use when a contingency arises. A utility owned off road capable vehicle utilized for a planned inaccessible pole replacement program would provide for the necessary changes to maintain the plant appropriately and would guarantee access during a contingency event.

<u>2011 Cost = $541,643</u>

NPEI's vehicle expenditures in 2011 include:

- Ford F-150 pick-up truck. $30K.
- 46' Material Handling Aerial Manlift and fiberglass body, with 2012 International 4400 chassis. $267K.
- Freightliner Aerial Device and Chassis. $323K.
- 2 trailers (Gooseneck trailer for off-road track machine and 55' pole trailer). $75K.

NPEI notes that the Freightliner Aerial Device and Chassis was purchased to replace a 2009 bucket truck (Truck #55) that was involved in an accident during October 2011. The cost of the replacement truck was largely covered by insurance proceeds. NPEI had originally budgeted to purchase an additional chassis for an RBD in 2011, with the RBD itself to be purchased in 2012. However, the additional chassis was not purchased in 2011, in order that the budgeted amount of $80K could be used instead to cover the insurance proceeds shortfall on the replacement for Truck #55.

2012 Cost = $1,160,649

NPEI's vehicle expenditures in 2012 include:

- Ford F-150 pick-up truck. $34K.
- GMC Cargo Van. $33K.
- 50' Terex RBD. $326K.
- 46' Material Handling Aerial Manlift. $272K.
- 2 x 42' Aerial Manlifts. $459K.
- 3 trailers (2 reel trailers and a 55' pole trailer). $37K.

An analysis of NPEI's vehicles in 2011 indicated that, at the time, NPEI has a fleet of 57 vehicles that were manufactured between 1985 and 2011. The fleet consisted of: Radial Boom Derricks (line trucks), Aerial Devices (bucket trucks), vans, SUVs, cube vans, pick-up trucks and in all had a total of 4.95 million kilometers on the chassis. Of the 57 vehicles, 17 or 29.8% were older than 10 years.

Four of the nine RBDs were between 18 and 24 years old. Five of the fourteen Aerial Devices were between 13 and 26 years old. Three of the twenty-one pick-up trucks were older than 10 years. Two of the ten vans & SUVs were older than 10 years, and the three dump trucks ranged in age from 16 to 24 years old.

The two 42' Aerial Manlifts purchased in 2012 replaced Truck #8 and Truck #28. Both of these vehicles were 36' Aerial Manlifts that were re-chassied between 1998 and 2003 with aerial devices that are between 22 and 24 years old.

The 46' Material Handling Aerial Manlift is an additional bucket truck with material handling capabilities. This was added to the fleet in order to provide each of NPEI's six line crews with two bucket trucks.

The chassis of the 50’ RBD was originally budgeted for in 2011. However, the budget funds were used to cover the replacement of Truck #55, which was involved in an accident in 2011. Both the chassis and device for the 50’ RBD were purchased in 2012.

<u>2013 Cost = $1,329,696</u>

NPEI’s vehicle expenditures in 2013 include:

- 5 x Ford F-150 pick-up trucks. $150K.
- Nissan Titan pick-up. $30K.
- 65’ RBD. $398K.
- 55’ Aerial Manlift. $329K.
- 45’ Material Handling Aerial Manlift. $284K.
- Dump / Hook Truck. $130K.

Six pick-ups were purchased in 2013 to replace 6 small vehicles which were disposed as they had reached the end of their useful life: on-call vehicle in the Niagara Falls area, Operations Supervisor in the Niagara Falls area, Operations Supervisor in the Smithville area, Lead hand in the Smithville area, engineering department in the Smithville area and engineering department in the Niagara Falls area.

The 65’ RBD was purchased to replace Truck #9, which was a 1992 International 4900 series with an RBD mounted on its chassis.

The 55’ Aerial Manlift was purchased to replace Truck #18, which was a 1985 Ford LN8000 with a double bucket aerial manlift mounted on its chassis.

The 46’ Material Handling Aerial Manlift was purchased to replace Truck #SV20, which was a 1998 Freightliner with an aerial manlift mounted on its chassis.

The multi-purpose hook truck with optional dump box and flatbed was purchased to replace Truck #2 which is a 1993 International 4600 series dump truck, and Truck #35 which is a 1987 Ford F-800 series with flatbed mounted on its chassis.

2014 Budgeted Cost = $672,000

NPEI's vehicle expenditures budgeted for 2014 include:

- 55' Double Bucket Material Handling Aerial Manlift. $350K.
- 46' Material Handling Aerial Manlift. $300K.
- 65' Pole Trailer. $22K.

Currently NPEI has a fleet of 61 vehicles that range in age from 1992 to 2013. Of the 61 vehicles 37 are greater than 3 tons and 24 are less than 3 tons. Currently, only one small vehicle is older than eight years and five large vehicles are greater than 15 years.

In 2014, NPEI included has proposed the replacement of two large vehicles greater than 3 tons. One 55' double bucket material handling aerial man-lift truck to replace a 13 year old 46' material handler in Smithville. This vehicle has over 350,000 kilometers and has reached the end of its life. The second vehicle is a 46' material handling aerial man-lift which is 17 years old and has also reached the end of its' useful life.

Also, proposed in the 2014 budget is the purchase of an extendable trailer capable of transporting 65' poles.

2015

NPEI has budgeted a total of $3,494,390 in vehicle costs for 2015 – 2019, including:

- Pick-up trucks (10). $370K.
- Vans (3). $139K.
- Cube Van (1). $61K.
- Bucket Trucks (5). $1,608K.
- Radial Boom Derricks (2). $892K.
- Backhoe (1). $70K.
- Pole Trailers (2). $44K.
- Go-Devil (1). $135K.
- 500 kVa portable generator (1). $175K.

NPEI expects that its next rebasing after 2015 will be in 2020. Therefore, NPEI has included in this current Application one fifth of the anticipated vehicle cost for 2015 – 2019: $3,494,390 / 5 = $698,878.

Allowance for Working Capital

In a letter dated April 12, 2012, the Board provided an update to electricity distributors and transmitters on the options established in the June 22, 2011, cost of service filing requirements for the calculation of allowance for working capital for the 2013 rate year. The applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study. NPEI notes that the subsequent filing requirements for the 2014 rate year (as revised on July 17, 2013) and the 2015 rate year (as revised on July 18, 2014) are consistent with the Board's letter of April 12, 2012, with respect to working capital allowance.

The Filing Requirement state *"The only exception is of the applicant has been directed by the Board to undertake a lead/lag study on which its current working capital is based. Under such circumstances, the applicant must either continue to use the results of that study or, in the event it wishes to propose a revision to its allowance, the applicant must file an updated study in support of its proposal."*

In NPEI's 2011 COS Rate Application (EB-2010-0138), the working capital allowance was one of the settled issues in NPEI's Partial Settlement Agreement (Issue 2.4). The amount of working capital allowance was agreed to by all parties to the settlement agreement, and subsequently accepted by the Board in the Decision on Partial Settlement Agreement and Procedural Order No. 3 (issued May 16, 2011).

NPEI notes that the settled working capital allowance in EB-2010-0138 was based on the Board's default value that was in effect at the time (15%). The completion of a lead/lag study was not suggested or agreed to by NPEI or other parties in NPEI's 2011 COS Application. Further, the Board has not ordered NPEI to complete a lead/lag study.

In view of all of the above, NPEI proposes the current default working capital allowance of 13% in this current Application. NPEI notes that the Board has approved a working capital allowance of 13% in several recent cost of service applications: Kitchener-Wilmot Hydro Inc. (EB-2013-0147), Burlington Hydro Inc. (EB-2013-0115), Cooperative Hydro Embrun Inc. (EB-2013-0122) and Hydro Hawksebury Inc. (EB-2013-0139).

The Filing Requirements indicate:

"The 13% Allowance Approach is calculated to be 13% of the sum of Cost of Power and controllable expenses (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

The commodity price estimate used to calculate the Cost of Power must be determined by the split between RPP and non-RPP customers based on actual data and using the most recent RPP (TOU) price. The calculation must reflect the most recent Uniform Transmission Rates approved by the Board (EB-2012-0031), issued on January 9, 2014 for 2014 rates and effective January 1, 2014. The calculation must include the impacts arising from the new Smart Metering Entity charge approved by the Board on March 28, 2013 in its EB-2012-0100/EB-2012-0211 Decision and Order."

In determining the commodity price estimate for calculating the cost of power, NPEI used 2013 actual consumption for RPP and Non-RPP kWh. Also, NPEI used the most recent RPP Report published by the Board on April 16, 2014 *(Regulated Price Plan Report May 1, 2014 to April 30, 2015).* Table 2-10 below shows the components of the RPP cost of $92.50 per MWh and Non-RPP cost of $90.96 per MWh that NPEI has incorporated into its cost of power calculations. NPEI notes that the source of these costs is Table ES-1 from the April 16, 2014 RPP Report.

Table 2-10: RPP and Non-RPP Commodity Price - May 1, 2014 to April 30, 2015

Supply Cost ($ / MWh) For the period from May 1, 2014 to April 30, 2015	Non-RPP	RPP
Forecast Wholesale Electricity Price	26.28	
Load-Weighted Price for RPP Consumers		28.70
Impact of Global Adjustment	64.68	64.68
Adjustment to Address Bias Towards Unfavourable Variance		1.00
Adjustment to Clear Existing Variance		(1.87)
Total Supply Cost ($ / MWh)	**90.96**	**92.50**

Next, NPEI calculated its weighted-average commodity price of $91.63 per MWh, based on the actual proportion of RPP and Non-RPP consumption for 2013. Table 2-11 below shows the derivation of the weighted-average commodity price.

Table 2-11: Weighted-Average Commodity Price - May 1, 2014 to April 30, 2015

	2013 Actual Consumption		
Customer Class	**Non-RPP**	**RPP**	**Total**
Residential	32,043,238	380,255,040	412,298,278
General Service < 50 kW	17,517,446	106,662,459	124,179,905
General Service > 50	621,052,486	34,916,319	655,968,805
Unmetered Scattered Load	-	2,247,877	2,247,877
Sentinel Lighting	50,679	214,940	265,619
Street Lighting	7,266,795	77,986	7,344,781
Total kWh	**677,930,643**	**524,374,622**	**1,202,305,265**
Total %	**56.39%**	**43.61%**	**100.00%**
Commodity Price	**90.96**	**92.50**	
Weighted Average Price ($90.96 * 56.39% + $92.50 * 43.61%)			**91.63**

NPEI's Cost of Power forecasts for the 2014 Bridge Year and 2015 Test Year were then completed based on the following:

- Forecast billed kWh and kW, where applicable, for 2014 and 2015 from NPEI's load forecast as detailed in Exhibit 3, Tab 1, Schedule 1.
- Forecast customer counts for the Residential and General Service < 50 kW classes for 2014 and 2015, as described in Exhibit 3, Tab 1, Schedule 1. These are used to

forecast the Smart Metering Entity charge.

- The Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50 kW customers, as approved by the Board in its EB-2012-0100 / EB-2012-0211 Decision and Order.
- NPEI's weighted average commodity price of $91.63 per MWh, as shown in Table 2-11 above.
- NPEI's current Board-approved transmission network and connection rates and low voltage rates, as approved in NPEI's 2014 IRM Rate Application (EB-2013-0154).
- NPEI's 2015 proposed low voltage rates, as set out in Exhibit 8, Tab 8, Schedule 1.
- NPEI's 2015 proposed transmission network and connection rates, as detailed in Exhibit 8, Tab 3, Schedule 1. NPEI confirms that the 2015 proposed transmission rates reflect the most recent Uniform Transmission Rates as approved by the Board in its EB-2012-0031 Decision and Order.
- The Wholesale Market Service rate of $0.0044 per kWh and the Rural and Remote Protection Rate of $0.0013 per kWh, as detailed in Exhibit 8, Tab 5, Schedule 1.

NPEI's resulting Cost of Power forecast for the 2014 Bridge Year is shown in Table 2-12 and a summary, by cost of power USoA account, is provided in Table 2-13.

Table 2-12: 2014 Cost of Power Forecast

Electricity - Commodity		2014		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	421,452,867	$0.0916	$38,618,425
General Service < 50 kW	kWh	126,285,583	$0.0916	$11,571,757
General Service > 50	kWh	683,099,206	$0.0916	$62,593,512
Unmetered Scattered Load	kWh	2,338,339	$0.0916	$214,266
Sentinel Lighting	kWh	275,102	$0.0916	$25,208
Street Lighting	kWh	7,766,241	$0.0916	$711,634
TOTAL		**1,241,217,338**		**$113,734,802**

Transmission - Network		2014		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	421,452,867	$0.0073	$3,076,606
General Service < 50 kW	kWh	126,285,583	$0.0066	$833,485
General Service > 50	kW	1,723,755	$2.7218	$4,691,717
Unmetered Scattered Load	kWh	2,338,339	$0.0066	$15,433
Sentinel Lighting	kW	713	$2.0152	$1,438
Street Lighting	kW	20,995	$2.0576	$43,199
TOTAL				**$8,661,877**

Transmission - Connection		2014		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	421,452,867	$0.0050	$2,107,264
General Service < 50 kW	kWh	126,285,583	$0.0044	$555,657
General Service > 50	kW	1,723,755	$1.7467	$3,010,883
Unmetered Scattered Load	kWh	2,338,339	$0.0044	$10,289
Sentinel Lighting	kW	713	$1.4595	$1,041
Street Lighting	kW	20,995	$1.3420	$28,175
TOTAL				**$5,713,309**

Wholesale Market Service		2014		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	421,452,867	$0.0044	$1,854,393
General Service < 50 kW	kWh	126,285,583	$0.0044	$555,657
General Service > 50	kWh	683,099,206	$0.0044	$3,005,637
Unmetered Scattered Load	kWh	2,338,339	$0.0044	$10,289
Sentinel Lighting	kWh	275,102	$0.0044	$1,210
Street Lighting	kWh	7,766,241	$0.0044	$34,171
TOTAL				**$5,461,356**

Rural Rate Assistance		2014		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	421,452,867	$0.0013	$547,889
General Service < 50 kW	kWh	126,285,583	$0.0013	$164,171
General Service > 50	kWh	683,099,206	$0.0013	$888,029
Unmetered Scattered Load	kWh	2,338,339	$0.0013	$3,040
Sentinel Lighting	kWh	275,102	$0.0013	$358
Street Lighting	kWh	7,766,241	$0.0013	$10,096
TOTAL				**$1,613,583**

Low Voltage		2014		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	402,178,821	$0.0005	$201,089
General Service < 50 kW	kWh	120,510,242	$0.0004	$48,204
General Service > 50	kW	1,723,755	$0.1592	$274,422
Unmetered Scattered Load	kWh	2,231,402	$0.0004	$893
Sentinel Lighting	kW	713	$0.1330	$95
Street Lighting	kW	20,995	$0.1223	$2,568
TOTAL				**$527,270**

Smart Metering Entity		2014		
Class per Load Forecast	**Fixed**	**Billing Determinants**	**Rate**	**Amount**
Residential	# customers	560,023	$0.7900	$442,418
General Service < 50 kW	# customers	52,204	$0.7900	$41,241
General Service > 50		0	$0.7900	$0
Unmetered Scattered Load		0	$0.7900	$0
Sentinel Lighting		0	$0.7900	$0
Street Lighting		0	$0.7900	$0
TOTAL				**$483,659**
				$136,195,856

Table 2-13: 2014 Cost of Power Forecast by Account

Cost of Power Account	**2014 Cost**
4705 - Power Purchased	$73,074,610
4707 - Charges - Global Adjustment	$40,660,192
4708 - Charges-WMS	$7,074,939
4714 - Charges-NW	$8,661,877
4716 - Charges-CN	$5,713,309
4750 - Low Voltage	$527,270
4751 - SME Charges	$483,659
TOTAL	**136,195,856**

NPEI notes that in Table 2-13 above, the 2014 forecast commodity cost of $113,734,802 (including global adjustment) has been split between accounts 4705 and 4707 based on historical proportions.

NPEI's resulting Cost of Power forecast for the 2015 Test Year is shown in Table 2-14 and a summary, by cost of power USoA account, is provided in Table 2-15.

Table 2-14: 2015 Cost of Power Forecast

Electricity - Commodity		2015		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	418,296,544	$0.0916	$38,329,205
General Service < 50 kW	kWh	124,431,272	$0.0916	$11,401,844
General Service > 50	kWh	689,489,049	$0.0916	$63,179,024
Unmetered Scattered Load	kWh	2,321,201	$0.0916	$212,696
Sentinel Lighting	kWh	271,893	$0.0916	$24,914
Street Lighting	kWh	7,836,336	$0.0916	$718,056
TOTAL		**1,242,646,296**		**$113,865,739**

Transmission - Network		2015		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	418,296,544	$0.0076	$3,188,583
General Service < 50 kW	kWh	124,431,272	$0.0069	$857,559
General Service > 50	kW	1,739,879	$2.8421	$4,944,997
Unmetered Scattered Load	kWh	2,321,201	$0.0069	$15,997
Sentinel Lighting	kW	705	$2.1043	$1,484
Street Lighting	kW	21,184	$2.1486	$45,516
TOTAL				**$9,054,136**

Transmission - Connection		2015		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	418,296,544	$0.0052	$2,163,990
General Service < 50 kW	kWh	124,431,272	$0.0046	$566,478
General Service > 50	kW	1,739,879	$1.8073	$3,144,405
Unmetered Scattered Load	kWh	2,321,201	$0.0046	$10,567
Sentinel Lighting	kW	705	$1.5101	$1,065
Street Lighting	kW	21,184	$1.3885	$29,415
TOTAL				**$5,915,920**

Wholesale Market Service		2015		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	418,296,544	$0.0044	$1,840,505
General Service < 50 kW	kWh	124,431,272	$0.0044	$547,498
General Service > 50	kWh	689,489,049	$0.0044	$3,033,752
Unmetered Scattered Load	kWh	2,321,201	$0.0044	$10,213
Sentinel Lighting	kWh	271,893	$0.0044	$1,196
Street Lighting	kWh	7,836,336	$0.0044	$34,480
TOTAL				**$5,467,644**

Rural Rate Assistance		2015		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	418,296,544	$0.0013	$543,786
General Service < 50 kW	kWh	124,431,272	$0.0013	$161,761
General Service > 50	kWh	689,489,049	$0.0013	$896,336
Unmetered Scattered Load	kWh	2,321,201	$0.0013	$3,018
Sentinel Lighting	kWh	271,893	$0.0013	$353
Street Lighting	kWh	7,836,336	$0.0013	$10,187
TOTAL				**$1,615,440**

Low Voltage		2015		
Class per Load Forecast	**Volumetric**	**Billing Determinants**	**Rate**	**Amount**
Residential	kWh	399,166,843	$0.0005	$199,583
General Service < 50 kW	kWh	118,740,733	$0.0004	$47,496
General Service > 50	kW	1,739,879	$0.1643	$285,862
Unmetered Scattered Load	kWh	2,215,047	$0.0004	$886
Sentinel Lighting	kW	705	$0.1372	$97
Street Lighting	kW	21,184	$0.1262	$2,673
TOTAL				**$536,598**

Smart Metering Entity		2015		
Class per Load Forecast	**Fixed**	**Billing Determinants**	**Rate**	**Amount**
Residential	# customers	564,799	$0.7900	$446,191
General Service < 50 kW	# customers	52,625	$0.7900	$41,574
General Service > 50		0	$0.7900	$0
Unmetered Scattered Load		0	$0.7900	$0
Sentinel Lighting		0	$0.7900	$0
Street Lighting		0	$0.7900	$0
TOTAL				**$487,765**
				$136,943,243

Table 2-15: 2015 Cost of Power Forecast by Account

Cost of Power Account	2015 Cost
4705 - Power Purchased	$73,158,738
4707 - Charges - Global Adjustment	$40,707,002
4708 - Charges-WMS	$7,083,084
4714 - Charges-NW	$9,054,136
4716 - Charges-CN	$5,915,920
4750 - Low Voltage	$536,598
4751 - SME Charges	$487,765
TOTAL	**136,943,243**

NPEI notes that in Table 2-15 above, the 2015 forecast commodity cost of $113,865,739 (including global adjustment) has been split between accounts 4705 and 4707 based on historical proportions.

Details of NPEI's working capital expenses, by USoA account, are provided in Table 2-16 below for 2011 Board Approved, 2011 to 2013 Actual, the 2014 Bridge Year and the 2015 Test Year. NPEI notes that the 2014 amounts exclude Smart Meter OM&A expenses that relate to prior years, and were brought to the income statement from the smart meter variance accounts in 2014 as a result of the Board's Decision and Order in NPEI's Smart Meter Application (EB-2013-0359).

Table 2-16: Details of Working Capital Allowance

Distribution Expenses - Operation	2011 Board Appoved	WC Allowance 15%	2011 Actual	WC Allowance 15%	2012 Actual	WC Allowance 15%	2013 Actual	WC Allowance 15%	2014 Bridge	WC Allowance 15%	2015 Test	WC Allowance 13%
5005-Operation Supervision and Engineering	648,571	97,286	689,565	103,435	688,630	103,294	723,775	108,566	751,531	112,730	784,680	102,008
5010-Load Dispatching	43,800	6,570	42,648	6,397	43,296	6,494	38,222	5,733	46,000	6,900	46,000	5,980
5012-Station Buildings and Fixtures Expense	73,725	11,059	69,484	10,423	127,822	19,173	65,932	9,890	85,209	12,781	111,346	14,475
5014-Transformer Station Equipment - Operation Labour	11,507	1,726	7,210	1,081	29,298	4,395	11,484	1,723	13,850	2,078	16,760	2,179
5015-Transformer Station Equipment - Operation Supplies and Expenses	54,733	8,210	101,958	15,294	94,878	14,232	141,834	21,275	120,200	18,030	148,019	19,242
5016-Distribution Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-	-	-	-
5017-Distribution Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	-
5020-Overhead Distribution Lines and Feeders - Operation Labour	197,358	29,604	214,469	32,170	203,079	30,462	197,145	29,572	206,000	30,900	228,331	29,683
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	10,421	1,563	7,082	1,062	71,802	10,770	14,775	2,216	12,000	1,800	15,934	2,071
5030-Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-
5035-Overhead Distribution Transformers- Operation	-	-	-	-	-	-	-	-	-	-	-	-
5040-Underground Distribution Lines and Feeders - Operation Labour	72,606	10,891	86,498	12,975	82,226	12,334	76,754	11,513	84,500	12,675	90,145	11,719
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	194,991	29,249	247,130	37,069	276,192	41,429	250,002	37,500	251,000	37,650	264,826	34,427
5050-Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-
5055-Underground Distribution Transformers - Operation	-	-	-	-	-	-	651	98	600	90	319	41
5060-Street Lighting and Signal System Expense	-	-	-	-	-	-	-	-	-	-	-	-
5065-Meter Expense	489,927	73,489	608,449	91,267	499,089	74,863	427,572	64,136	406,000	60,900	479,640	62,353
5070-Customer Premises - Operation Labour	96,423	14,463	101,235	15,185	87,166	13,075	121,019	18,153	98,050	14,708	99,134	12,887
5075-Customer Premises - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-
5085-Miscellaneous Distribution Expense	1,623,583	243,537	1,896,259	284,439	2,123,409	318,511	2,062,008	309,301	2,224,713	333,707	2,006,016	260,782
5090-Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-
5096-Other Rent	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Operation	3,517,644	527,647	4,071,987	610,798	4,326,888	649,033	4,131,174	619,676	4,299,653	644,948	4,291,150	557,849

Distribution Expenses - Maintenance	2011 Board Appoved	WC Allowance 15%	2011 Actual	WC Allowance 15%	2012 Actual	WC Allowance 15%	2013 Actual	WC Allowance 15%	2014 Bridge	WC Allowance 15%	2015 Test	WC Allowance 13%
5105-Maintenance Supervision and Engineering	462,681	69,402	464,602	69,690	478,494	71,774	492,771	73,916	511,714	76,757	546,434	71,036
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	-	-	-	-	-	-	-	-	-
5112-Maintenance of Transformer Station Equipment	-	-	-	-	82,177	12,327	1,115	167	1,200	180	22,667	2,947
5114-Maintenance of Distribution Station Equipment	4,767	715	2,762	414	28,485	4,273	33,542	5,031	22,700	3,405	47,309	6,150
5120-Maintenance of Poles, Tow ers and Fixtures	151,573	22,736	162,672	24,401	166,994	25,049	157,254	23,588	177,250	26,587	219,074	28,480
5125-Maintenance of Overhead Conductors and Devices	877,452	131,618	742,311	111,347	798,301	119,745	613,407	92,011	672,986	100,948	775,838	100,859
5130-Maintenance of Overhead Services	150,393	22,559	158,631	23,795	160,458	24,069	154,111	23,117	164,958	24,744	177,896	23,127
5135-Overhead Distribution Lines and Feeders - Right of Way	352,301	52,845	256,403	38,460	208,144	31,222	244,450	36,667	261,000	39,150	264,233	34,350
5145-Maintenance of Underground Conduit	42,841	6,426	31,457	4,719	39,818	5,973	25,153	3,773	29,661	4,449	31,510	4,096
5150-Maintenance of Underground Conductors and Devices	249,450	37,417	191,440	28,716	197,019	29,553	205,312	30,797	200,167	30,025	217,612	28,290
5155-Maintenance of Underground Services	91,252	13,688	122,745	18,412	83,461	12,519	72,640	10,896	77,118	11,568	90,440	11,757
5160-Maintenance of Line Transformers	132,000	19,800	68,849	10,327	132,652	19,898	145,430	21,815	131,562	19,734	156,747	20,377
5165-Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	-	-
5170-Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-	-	-	-
5172-Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-
5175-Maintenance of Meters	13,426	2,014	7,909	1,186	5,214	782	4,366	655	5,000	750	5,163	671
5178-Customer Installations Expenses- Leased Property	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Maintenance	2,528,132	379,220	2,209,781	331,467	2,381,216	357,182	2,149,552	322,433	2,255,316	338,297	2,554,924	332,140

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Billing and Collecting	2011 Board Appoved	WC Allowance 15%	2011 Actual	WC Allowance 15%	2012 Actual	WC Allowance 15%	2013 Actual	WC Allowance 15%	2014 Bridge	WC Allowance 15%	2015 Test	WC Allowance 13%
5305-Supervision	480,012	72,002	486,752	73,013	576,200	86,430	624,638	93,696	921,989	138,298	1,089,144	141,589
5310-Meter Reading Expense	433,321	64,998	362,810	54,422	188,961	28,344	154,043	23,106	356,100	53,415	478,850	62,250
5315-Customer Billing	1,862,527	279,379	2,003,416	300,512	1,999,682	299,952	2,060,234	309,035	2,812,441	421,866	3,083,889	400,906
5320-Collecting	469,501	70,425	450,652	67,598	436,346	65,452	429,058	64,359	423,331	63,500	446,182	58,004
5325-Collecting- Cash Over and Short	-	-	129	19	0	0	70	11	-	-	-	-
5330-Collection Charges	-	-	-	-	-	-	-	-	-	-	-	-
5335-Bad Debt Expense	410,000	61,500	330,713	49,607	266,257	39,939	223,842	33,576	265,000	39,750	265,000	34,450
5340-Miscellaneous Customer Accounts Expenses	258,306	38,746	241,522	36,228	230,190	34,528	243,808	36,571	272,950	40,942	246,819	32,086
Subtotal Billing and Collecting	3,913,667	587,050	3,875,994	581,399	3,697,637	554,646	3,735,692	560,354	5,051,811	757,772	5,609,882	729,285

Community Relations (including sales expenses)	2011 Board Appoved	WC Allowance 15%	2011 Actual	WC Allowance 15%	2012 Actual	WC Allowance 15%	2013 Actual	WC Allowance 15%	2014 Bridge	WC Allowance 15%	2015 Test	WC Allowance 13%
5405-Supervision	-	-	-	-	-	-	-	-	-	-	-	-
5410-Community Relations - Sundry	81,464	12,220	60,687	9,103	79,068	11,860	81,554	12,233	85,525	12,829	69,600	9,048
5415-Energy Conservation	-	-	-	-	-	-	-	-	-	-	-	-
5420-Community Safety Program	-	-	-	-	-	-	-	-	-	-	-	-
5425-Miscellaneous Customer Service and Informational Expenses	-	-	-	-	-	-	-	-	-	-	-	-
5505-Supervision	-	-	-	-	-	-	-	-	-	-	-	-
5510-Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-	-	-	-
5515-Advertising Expense	-	-	-	-	-	-	-	-	-	-	-	-
5520-Miscellaneous Sales Expense	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Community Relations	81,464	12,220	60,687	9,103	79,068	11,860	81,554	12,233	85,525	12,829	69,600	9,048

Administrative and General Expenses	2011 Board Appoved	WC Allowance 15%	2011 Actual	WC Allowance 15%	2012 Actual	WC Allowance 15%	2013 Actual	WC Allowance 15%	2014 Bridge	WC Allowance 15%	2015 Test	WC Allowance 13%
5605-Executive Salaries and Expenses	323,267	48,490	370,546	55,582	359,989	53,998	397,095	59,564	409,626	61,444	408,989	53,169
5610-Management Salaries and Expenses	1,776,977	266,547	1,625,968	243,895	1,713,306	256,996	1,673,768	251,065	1,935,977	290,396	2,018,698	262,431
5615-General Administrative Salaries and Expenses	421,595	63,239	438,121	65,718	456,970	68,545	446,358	66,954	470,521	70,578	453,497	58,955
5620-Office Supplies and Expenses	116,319	17,448	101,233	15,185	83,384	12,508	76,251	11,438	75,000	11,250	76,500	9,945
5625-Administrative Expense Transferred Credit	-	-	-	-	-	-	-	-	-	-	-	-
5630-Outside Services Employed	39,900	5,985	39,600	5,940	39,600	5,940	40,800	6,120	45,000	6,750	50,000	6,500
5635-Property Insurance	209,777	31,467	241,376	36,206	221,161	33,174	284,892	42,734	281,000	42,150	288,605	37,519
5640-Injuries and Damages	-	-	-	-	-	-	-	-	-	-	-	-
5645-Employee Pensions and Benefits	-	-	-	-	-	-	-	-	-	-	-	-
5646-Employee Pensions and OPEB	-	-	-	-	-	-	-	-	-	-	-	-
5647-Employee Sick Leave	-	-	-	-	-	-	-	-	-	-	-	-
5650-Franchise Requirements	-	-	-	-	-	-	-	-	-	-	-	-
5655-Regulatory Expenses	268,429	40,264	239,075	35,861	242,930	36,439	222,003	33,300	230,000	34,500	280,313	36,441
5660-General Advertising Expenses	-	-	-	-	-	-	-	-	-	-	-	-
5665-Miscellaneous General Expenses	53,810	8,071	51,819	7,773	52,118	7,818	58,770	8,816	37,000	5,550	51,447	6,688
5670-Rent	-	-	-	-	-	-	-	-	-	-	-	-
5672-Lease Payment Expense	-	-	-	-	-	-	-	-	-	-	-	-
5675-Maintenance of General Plant	564,320	84,648	556,910	83,536	501,708	75,256	556,822	83,523	537,680	80,652	563,580	73,265
6205-Donations - LEAP Funding - Sub-Account	38,906	5,836	38,906	5,836	38,906	5,836	38,906	5,836	38,906	5,836	37,166	4,832
6215-Penalties	-	-	-	-	167,381	25,107	-	-	-	-	-	-
Subtotal Administrative and General Expense	3,813,300	571,995	3,703,555	555,533	3,877,454	581,618	3,795,664	569,350	4,060,709	609,106	4,228,792	549,743

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Property Taxes	2011 Board Appoved	WC Allowance 15%	2011 Actual	WC Allowance 15%	2012 Actual	WC Allowance 15%	2013 Actual	WC Allowance 15%	2014 Bridge	WC Allowance 15%	2015 Test	WC Allowance 13%
6105-Taxes Other Than Income Taxes	222,474	33,371	185,288	27,793	406,629	60,994	258,673	38,801	281,600	42,240	287,232	37,340
Subtotal Property Taxes	222,474	33,371	185,288	27,793	406,629	60,994	258,673	38,801	281,600	42,240	287,232	37,340
Cost of Power	**2011 Board Appoved**	**WC Allowance 15%**	**2011 Actual**	**WC Allowance 15%**	**2012 Actual**	**WC Allowance 15%**	**2013 Actual**	**WC Allowance 15%**	**2014 Bridge**	**WC Allowance 15%**	**2015 Test**	**WC Allowance 13%**
4705-Pow er Purchased	42,651,530	6,397,730	64,832,841	9,724,926	64,554,078	9,683,112	69,265,573	10,389,836	73,074,610	10,961,192	73,158,738	9,510,636
4707-Charges-Global Adjustment	43,831,333	6,574,700	27,227,797	4,084,170	33,743,178	5,061,477	38,551,759	5,782,764	40,660,192	6,099,029	40,707,002	5,291,910
4708-Charges-WMS	8,396,710	1,259,506	8,462,016	1,269,302	8,186,728	1,228,009	7,454,786	1,118,218	7,074,939	1,061,241	7,083,084	920,801
4714-Charges-NW	7,803,026	1,170,454	7,793,522	1,169,028	8,708,520	1,306,278	8,975,194	1,346,279	8,661,877	1,299,282	9,054,136	1,177,038
4750-Charges-LV	5,603,528	840,529	5,675,465	851,320	5,502,320	825,348	5,454,832	818,225	5,713,309	856,996	5,915,920	769,070
4751-Charges-Smart Metering Entity	554,681	83,202	651,040	97,656	539,212	80,882	537,672	80,651	527,270	79,091	536,598	69,758
	-	-	-	-	-	-	320,166	48,025	483,659	72,549	487,765	63,409
Subtotal Cost of Power	108,840,807	16,326,121	114,642,681	17,196,402	121,234,036	18,185,105	130,559,982	19,583,997	136,195,856	20,429,378	136,943,243	17,802,622
Total Working Capital Expense	122,917,489	18,437,623	128,749,974	19,312,496	136,002,927	20,400,439	144,712,291	21,706,844	152,230,470	22,834,570	153,984,823	20,018,027

Table 2-17 below shows year over year variances of NPEI's working capital for 2011 Board Approved, 2011 to 2013 Actual, the 2014 Bridge Year and the 2015 Test Year. NPEI notes that the 2014 amounts exclude Smart Meter OM&A expenses that relate to prior years, and were brought to the income statement from the smart meter variance accounts in 2014 as a result of the Board's Decision and Order in NPEI's Smart Meter Application (EB-2013-0359).

Table 2-17: Working Capital Allowance Variances

	2011	2011	2011 Actual	2012	2012 Actual	2013	2013 Actual	2014	2014 Bridge	2015	2015 Test	2015 Test
								Excludes SM Expenses from Prior Years				vs 2011 Board
	Board approved	Actual	vs Board Approved	Actual	vs 2011 Actual	Actual	vs 2012 Actual	Bridge Year	vs 2013 Actual	Test Year	vs 2014 Bridge	Approved
Distribution Expenses - Operation	3,517,644	4,071,987	554,343	4,326,888	254,901	4,131,174	(195,714)	4,299,653	168,479	4,291,150	(8,503)	773,506
Distribution Expenses - Maintenance	2,528,132	2,209,781	(318,352)	2,381,216	171,435	2,149,552	(231,665)	2,255,316	105,765	2,554,924	299,608	26,791
Billing and Collecting	3,913,667	3,875,994	(37,673)	3,697,637	(178,357)	3,735,692	38,055	5,051,811	1,316,119	5,609,882	558,071	1,696,215
Community Relations	81,464	60,687	(20,777)	79,068	18,381	81,554	2,486	85,525	3,971	69,600	(15,925)	(11,864)
Administrative and General Expenses	3,813,300	3,703,555	(109,745)	3,877,454	173,898	3,795,664	(81,789)	4,060,709	265,044	4,228,792	168,083	415,492
Taxes Other Than Income Taxes	222,474	185,288	(37,186)	406,629	221,341	258,673	(147,956)	281,600	22,927	287,232	5,632	64,758
Total Eligible Distribution Expenses	14,076,682	14,107,292	30,610	14,768,891	661,599	14,152,309	(616,583)	16,034,614	1,882,306	17,041,580	1,006,966	2,964,898
Power Supply Expenses	108,840,807	114,642,681	5,801,874	121,234,036	6,591,354	130,559,982	9,325,946	136,195,856	5,635,874	136,943,243	747,387	28,102,436
Total Working Capital Expenses	122,917,489	128,749,974	5,832,485	136,002,927	7,252,954	144,712,291	8,709,363	152,230,470	7,518,179	153,984,823	1,754,353	31,067,334
Working Capital Allowance Rate	15%	15%	15%	15%	15%	15%	15%	15%	15%	13%	13%	5.09%
Working Capital Allowance	18,437,623	19,312,496	874,873	20,400,439	1,087,943	21,706,844	1,306,405	22,834,570	1,127,727	20,018,027	- 2,816,543	1,580,404

<u>2011 Actual versus 2011 Board Approved</u>

NPEI's 2011 Actual working capital allowance was $874,873 higher than 2011 Board approved ($19,312,496 actual versus $18,437,623 Board approved). This is largely due to an increase in power supply expense of $5,801,874 ($114,642,681 actual versus $108,840,807 Board approved). The difference between 2011 Actual eligible distribution expenses and 2011 Board approved is immaterial ($30,610).

<u>2012 Actual versus 2011 Actual</u>

NPEI's 2012 Actual working capital allowance was $1,087,943 higher than 2011 Actual ($20,400,439 in 2012 versus $19,312,496 in 2011). This is largely due to an increase in power supply expense of $7,252,954 ($136,002,927 in 2012 versus $128,749,974 in 2011). The 2012 Actual eligible distribution expenses were $661,559 higher than 2011 Actual.

2013 Actual versus 2012 Actual

NPEI's 2013 Actual working capital allowance was $1,306,405 higher than 2012 Actual ($21,706,844 in 2013 versus $20,400,439 in 2012). This is largely due to an increase in power supply expense of $9,325,946 ($130,559,982 in 2013 versus $121,234,036 in 2012). The 2013 Actual eligible distribution expenses decreased $616,583 from 2012 Actual.

2014 Bridge Year versus 2013 Actual

NPEI's 2014 Bridge Year working capital allowance is $1,127,727 higher than 2013 Actual ($22,834,570 in 2014 versus $21,706,844 in 2013). This is largely due to an increase in power supply expense of $5,635,874 ($136,195,856 in 2014 versus $130,559,982 in 2013). The 2014 Bridge Year eligible distribution expenses are forecast to increase by $1,882,306 over 2013 Actual.

2015 Test Year versus 2014 Bridge Year

NPEI's proposed 2015 Test Year working capital allowance is $2,816,543 lower than the 2014 Bridge Year ($20,018,027 in 2015 versus $22,834,570 in 2014). The decrease is largely due to the change in working capital allowance percentage from 15% to 13%. Forecast power supply expense increased by $747,387 ($136,943,243 in 2015 versus $136,195,856 in 2014). The proposed 2015 Test Year eligible distribution expenses are forecast to increase by $1,006,966 over the 2014 Bridge Year.

2015 Test Year versus 2011 Board Approved

NPEI's proposed 2015 Test Year working capital allowance is $1,580,404 (5.09%) higher than 2011 Board Approved ($20,018,027 in 2015 versus $18,437,623 2011 Board approved). The most significant driver of the difference is the increase in power supply expense of $28,102,436 ($136,943,243 in 2015 versus $108,840,807 2011 Board approved). The proposed 2015 eligible distribution expenses are $2,964,898 higher than 2011 Board approved ($17,041,580 in 2015 versus $14,076,682 2011 Board approved). These increases are partially offset by the decrease in working capital allowance percentage from 15% to 13%.

Further details of NPEI’s eligible distribution expenses are provided in Exhibit 4.

Treatment of Stranded Assets Related to Smart Meter Deployment

The Board's *Guideline G-2008-0002: Smart Meters Funding and Cost Recovery* provided two options regarding the accounting treatment of stranded meters. The first option was to leave the stranded meter costs in rate base (i.e. Account 1860) while the second option was to record these costs in "Sub-account Stranded Meter Costs" of Account 1555: Smart Meter Capital and Recovery Offset Variance.

NPEI confirms that it has used the second option mentioned above; NPEI's stranded meter costs are recorded in the Stranded Meter sub-account of Account 1555.

In the *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition,* the Board states:

"The Board indicated that, for those distributors that are scheduled to file a cost of service application for 2012 distribution rates, the Board expects that they will apply for the disposition of smart meter costs and subsequent inclusion in rate base. For those distributors that are expected to remain in IRM, the Board expects these distributors to file a stand-alone application with the Board seeking final approval for smart meter related costs."

Consistent with the guidance provided in the G-2011-0001 Guideline, NPEI filed a stand-alone Smart Meter Application with the Board on October 10, 2013 (EB-2013-0359). The Board's Decision and Order in EB-2013-0359, issued February 27, 2014, provided for the disposition of NPEI's smart meter variance account balances, with the exception of stranded meters sub-account. The Board indicated *"If NPEI requests disposition of the balances of the stranded meters sub-account in its next cost of service application, the Board expects that NPEI will adequately document the gross book value and accumulated depreciation, and hence the NBV of stranded meters for which it will seek recovery through stranded meter rate riders."*

In accordance with the Board's EB-2013-0359 Decision and Order, NPEI is requesting disposition of its stranded meter costs in this current Application. Further details are provided in Exhibit 9, Tab 3, Schedule 12.

NPEI has completed the Board's Appendix 2-S, which is included at Exhibit 2, Tab 1, Schedule 4, Attachment 1.

Attachment 1 of 1

OEB Appendix 2-S

File Number:	EB-2014-0096
Exhibit:	2
Tab:	1
Schedule:	4
Page:	1
Date:	29-Aug-14

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009		$ 631,140	$ 400,378		$ 230,762	$ -	$ 230,762
2010		$ 5,014,897	$ 3,596,059		$ 1,418,838	$ 8,208	$ 1,410,630
2011		$ 5,251,158	$ 3,825,272		$ 1,425,886	$ 10,938	$ 1,414,947
2012		$ 5,392,714	$ 3,985,137		$ 1,407,577	$ 10,938	$ 1,396,638
2013		$ 5,392,714	$ 4,041,348		$ 1,351,366	$ 11,451	$ 1,339,915
2014	(1) Includes forecast 2014 depreciation of $56,211	$ 5,392,714	$ 4,097,559		$ 1,295,155	$ 11,451	$ 1,283,705

File Number: EB-2014-0096

Date Filed: September 23, 2014

Exhibit 2

Tab 2 of 3

Capital Expenditures

Consolidated Distribution System Plan

NPEI's Consolidated Distribution Plan is included at Exhibit 2, Tab 2, Schedule 1, Attachment 1.

NPEI has completed the Board's Appendix 2-AB, which is included at Exhibit 2, Tab 2, Schedule 1, Attachment 2.

NPEI has completed the Board's Appendix 2-AA, which is included at Exhibit 2, Tab 2, Schedule 1, Attachment 3.

Appendix 2-AB shows variances in plan versus actual capital expenditures, for the categories of System Access, System Renewal, System Service and General Plant, and system operating and maintenance expense. Additional variance analysis is provided below.

<u>Comparison of Plan Versus Actual by Category 2010 – 2014</u>

The markedly different variances of plan versus actual from 2010 to 2014 are described below.

CATEGORY	2010		2011		2012		2013		2014 Bridge Year	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*
System Access	2,130	2,558	2,199	942	1,630	1,086	2,031	1,997	1,731	1,731
System Renewal	2,998	2,769	4,768	4,162	7,870	5,150	5,838	5,907	7,307	7,307
System Service	6,699	6,465	1,512	1,966	2,362	1,424	1,100	847	580	2,483
General Plant	1,820	1,621	1,123	1,280	2,769	2,621	6,028	3,897	3,267	3,267
TOTAL EXPENDITURE	**13,647**	**13,413**	**9,603**	**8,350**	**14,631**	**10,280**	**14,997**	**12,649**	**12,885**	**14,788**

<u>2010</u>

System Access: Planned = $2,130K, Actual = $2,558K, Variance = $428K, 20.1%

This variance is mainly due to municipal line relocations and subdivision projects being greater than budgeted. Projects contributing to this variance include:

- South Pelham Street - $167K
- Subdivisions - $83K
- Oakwood Drive relocation - $160K

2011

System Access: Planned = $2,199K, Actual = $942K, Variance = ($1,257K), -57.2%

This variance is mainly due to subdivision projects being lower than budgeted and capital contributions being greater than budgeted. Projects contributing to this variance include:

- Subdivisions – ($360K)
- Capital Contributions – ($722K)

System Service: Planned = $1,512K, Actual = $1,966K, Variance = $454K, 30.0%

This variance is mainly due to a 2010 system service project that was largely deferred until 2011 (Robinson St. Primary Extension), partially offset by lower than budgeted switchgear replacement and double circuit extension on Montrose Road. Projects contributing to this variance include:

- Robinson St. Primary Extension– $733K
- KM2 and KM6 Montrose – Mcleod – ($253)
- Switchgear Replacement – ($209K)

2012

System Access: Planned = $1,630K, Actual = $1,086K, Variance = ($544K), -33.4%

This variance is mainly due capital contributions being greater than budgeted. Projects contributing to this variance include:

- Capital Contributions – ($627K)

System Renewal: Planned = $7,870K, Actual = $5,150K, Variance = ($2,720K), -34.6%

In 2012, based on discussions with Hydro One Networks, NPEI budgeted to purchase an asset from Hydro One at a cost of $2.4 million. This purchase did not occur. Projects contributing to this variance include:

- Budgeted System Renewal asset not purchased – ($2,360K)

System Service: Planned = $2,362K, Actual = $1,424K, Variance = ($938K), -39.7%

This variance is mainly due to the fact that smart meter capital costs were included in the budgeted amount, under system service. The actual smart meter capital costs were recorded in the smart meter variance account. This variance reverses in 2014 as smart meter capital costs are moved to rate base. Projects contributing to this variance include:

- Smart Meter costs included in system service planned amount – ($1,114K).

<u>2013</u>

System Service: Planned = $1,100K, Actual = $847K, Variance = ($253K), -23.0%

This variance is mainly due lower than budgeted switchgear and sectionalizing costs. Projects contributing to this variance include:

- Switchgear Replacement – ($136K).
- Sectionalizing switch replacement – ($140K)

General Plant: Planned = $6,028K, Actual = $3,897K, Variance = ($2,131K), -35.3%

This variance is mainly due to renovations of NPEI's stores and operations area, which were originally budgeted for 2013 being deferred until 2014. Hardware and Software purchases in 2013 were also less than budgeted.

- Deferred building projects – ($1,523K).
- Hardware – ($318K)
- Software – ($168K).

System O&M: Planned = $6,880K, Actual = $6,281K, Variance = ($599K), -8.7%

NPEI's 2013 system O&M budgeted amount is based on 2012 actual values. More meter and engineering labour time ($284K) was spent on capital projects in 2013 than originally budgeted. Therefore, less maintenance work was performed than originally budgeted.

<u>2014</u>

System Service: Planned = $580K, Actual = $2,483K, Variance = $1,903K, 328.1%

This variance is due to capital costs moved from the smart meter variance accounts to rate base in 2014, as a result of the Board's Decision and Order in NPEI's Smart Meter Application

(EB-2013-0359). This represents the balance of smart meter capital costs from July 1, 2010 to December 31, 2013.

- Smart Meter Capital moved to rate base - $1,903K

Comparison of Actual Year over Year by Category 2010 – 2015

The markedly different variances of year over year actual from 2010 to 2015 are described below.

	Capital Expenditures Summary					
	2010	2011	2012	2013	2014 Projected	2015 Plan
System Access	2,558	942	1,086	1,997	1,731	2,429
system Renewal	2,769	4,162	5,150	5,907	7,307	6,383
System Service	6,465	1,966	1,424	847	2,483	926
General Plant	1,621	1,280	2,621	3,897	3,267	1,447
Total	13,413	8,350	10,281	12,648	14,788	11,185

2011 versus 2010

Total Capital Expenditures: 2010 = $13,413K, 2011 = $8,350K

Variance = ($5,033K), -37.7%

This variance is mainly due to smart meter capital costs of $4,175K that were transferred from NPEI's smart meter variance accounts to rate base in 2010. Also, NPEI collected $411K more in capital contributions in 2011 than in 2010.

2012 versus 2011

Total Capital Expenditures: 2011 = $8,350K, 2012 = $10,281K

Variance = $1,931K, 23.1%

Vehicle additions were $1,161K in 2012 (including 4 large vehicles) versus $542K in 2011 (including 2 large vehicles), which is an increase of $619K. Also, workspace optimization of existing office space took place in 2012, with a cost of $303K.

2013 versus 2012

Total Capital Expenditures: 2012 = $10,281K, 2013 = $12,648K

Variance = $2,367K, 23.0%

This variance is mainly due to building and yard projects completed at NPEI's Niagara Falls property: new wire building $907K, yard excavation $533K and high mast lighting $435K.

2014 versus 2013

Total Capital Expenditures: 2013 = $12,648K, 2014 Projected = $14,788K

Variance = $2,140K, 16.9%

This variance is mainly due to capital costs of $1,903K which were moved from NPEI's smart meter variance accounts to rate base in 2014.

2015 versus 2014

Total Capital Expenditures: 2014 Projected = $14,788K, 2015 Budget = $11,185K

Variance = ($3,603K), -24.4%

This variance is partly due to capital costs of $1,903K which were moved from NPEI's smart meter variance accounts to rate base in 2014. Also, all workspace optimization, yard and wire building projects from 2013 to 2014 were completed by the end of 2014.

Attachment 1 of 3

Consolidated Distribution System Plan

niagara
peninsula
energy

Our energy
works
for you.

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September 23, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

RE: Niagara Peninsula Energy Inc.
2015 Consolidated Distribution System Plan

Dear Ms. Walli:

Please find attached Niagara Peninsula Energy Inc.'s ("NPEI's") Consolidated Distribution System Plan ("DSP"), which has been prepared in accordance with Chapter 5 of the *Filing Requirements for Electricity Transmission and Distribution Applications.*

As directed in Chapter 2 of the Filing Requirements, NPEI has also included the DSP in Exhibit 2 of its 2015 Cost of Service Rate Application filing (EB-2014-0096).

On August 12th 2014, NPEI requested an update on the status of IRRP for Group 3 (Southern Ontario) from the OPA. An e-mail response dated August 13th was sent to NPEI from the OPA in response to this inquiry and is included in Appendix A of the DSP. As at September 23, 2014, NPEI had not yet received the letter from the OPA. NPEI will file its DSP with the OEB without the letter from the OPA in order to not further delay filing. Once the letter from the OPA is received NPEI will file it with the OEB under separate cover.

If any further information is required, please contact the undersigned.

Sincerely,

Tom Sielicki, C.E.T.
Vice-President of Engineering
Niagara Peninsula Energy Inc.
(905) 353-6016
Tom.Sielicki@npei.ca

Niagara Peninsula Energy Inc.

Distribution System Plan

2014

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EXECUTIVE SUMMARY

Niagara Peninsula Energy Inc. ("NPEI") is an Electrical Distribution Company servicing an area of approximately 820 square kilometers. NPEI's service area is composed of Niagara Falls, Lincoln, West Lincoln and the Village of Fonthill and its system contains a mix of urban and rural electrical distribution. Niagara Peninsula Energy's Mission is to deliver safe, efficient, and reliable electricity. Niagara Peninsula Energy employees provide the best possible service to all Customers, delivering environmentally responsible and sustainable energy for the future viability of our Communities.

In order to maintain the sustainability of its operations, sufficient funding to facilitate planning, equipment, personnel and systems must be in place to provide the core functions required. Establishing a sound and viable long-term plan for personnel recruitment and training, equipment procurement, software and technology tools to aid in asset management, design and modeling, communication systems, billing and accounting systems, are key to ensuring that these services are provided in an efficient and economical manner.

To demonstrate commitment to the efficient and economical provision of these services and to comply with the requirements of OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements, NPEI has developed this Distribution System Plan ("DSP"). An Asset Condition Assessment ("ACA"), developed by Kinectrics Inc., provides the basis for system renewal investments, the largest portion of NPEI's capital expenditures. The ACA was developed using data originating from regular programs established by NPEI, including sub-station maintenance and testing, pole testing, pad-mounted equipment inspections, kiosk inspections, manhole inspections, and sidewalk vault inspections. These inspection, testing, and maintenance programs are carried out by qualified contractors following criteria provided by NPEI to determine asset condition, public safety concerns, access issues, and to estimate remaining asset life. Digital images are obtained and the information is linked to the asset within the Geographic Information System (GIS), from which reports can be generated relating to quantities, age, type, condition and other relevant criteria. These reports are compiled to generate data required as input for the ACA. The Health Indices and flagged for actions strategies determined from the ACA provides data critical for long term planning and the development of the 2015 to 2019 Capital Plan as outlined in this DSP.

The DSP's purpose is to show how NPEI plans, manages and develops the electrical distribution system and associated infrastructure. It outlines the long term Capital Expenditure Plan to meet needs stemming from internal drivers, external drivers and strategic investments, while maintaining a reasonable impact on customers' rates and system performance.

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5.1 INTRODUCTION

The Ontario Energy Board's Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements ("Chapter 5 Filing Requirements") dated March 28, 2013, requires Local Distribution Companies ("LDC") to submit a Distribution System Plan ("DSP") as part of its Cost of Service ("COS") Distribution Rate Application. Niagara Peninsula Energy Inc. ("NPEI") has developed this DSP to comply with the filing requirements. The DSP has been prepared and formatted using the numbering and section headings as laid out in the Chapter 5 Filing Requirements.

5.2 DISTRIBUTION SYSTEM PLAN

5.2.1 Distribution System Plan Overview

NPEI is an LDC serving approximately 51,452 customers in the cities and townships of Fonthill (village of Pelham), Lincoln, Niagara Falls, and West Lincoln. NPEI distributes electricity to these customers from 7 transformer stations connected to approximately 2,000 kilometers of overhead and underground circuits.

Key Elements

NPEI Distribution System Plan (DSP) is based on the information and input from various sources, such as core business values, customer input, asset management planning strategies, and historical capital expenditure definition processes that contribute to the development of a business plan.

NPEI's Vision and Mission statement are at the core of distribution system planning:

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

Mission Statement: "To deliver 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".

NPEI strives to achieve its mission through key corporate business values. NPEI and its staff will maintain conduct with commitment to the values of:

- Responsibility- we provide services with safety first for our customers and employees
- Integrity- we are ethical and our actions are truthful and trustworthy
- Fairness- we treat everyone equally and free of bias
- 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

NPEI uses 5 key strategic objectives as the basis for business planning:

- CUSTOMER SATISFACTION
  - Enhance customer satisfaction through high quality service.
  - Promote the efficient use of electricity through education, and delivery of conservation initiatives.
  - Continue to deliver reliable electricity at reasonable rates.
  - Minimize system outages.

- FACILITIES OPTIMIZATION
  - Plan expansion of the transformation and distribution systems to meet the electrical needs of current and future customers.
  - Refurbish aging plant facilities and equipment in a cost effective manner.
  - Enhance system performance and reliability

- PUBLIC POLICY
  - Incorporate the Green Energy Act requirements into the system.
  - Implement Smart Grid initiatives to improve reliability and accommodate embedded generation.
  - Successfully implement conservation and demand programs.
  - Support environmental programs (Reduce, Reuse, and Recycle).

- SAFETY AND WELLNESS
  - Promote safety awareness for our associates and the community.
  - Strengthen NPEI's "Safety Culture"
  - Promote wellness initiatives with NPEI associates.

- CORPORATE LEADERSHIP
  - Provide our associates with the necessary skills to meet customer needs and expectations.
  - Maintain long-term financial viability.
  - Develop resources to promote the sustainability of our operations.
  - Maintain regulatory compliance.
  - Continue to build value for our Shareholders.

These strategic goals align themselves with 4 key criteria used in the prioritization of planned capital expenditures:

- Reliability / Performance
- Efficiency
- Safety
- Community Relations / Regulatory

This Distribution System Plan builds upon the Asset Management Plan (AMP) developed as part of the 2011 Distribution Rate Application. Many of the elements of this AMP have been incorporated into NPEI's DSP. In particular, the 2011 Asset Condition Assessment previously used to support NPEI's asset management strategies has been updated in 2014 by Kinectrics Inc. ("Kinectrics"). The report provided by Kinectrics is entitled: "Distribution Asset Condition Report - 2014" and is included in Appendix E of this document. The asset condition data used to support the Asset Condition Assessment are housed in NPEI's Geographic Information system. Data from the GIS, current as of March 31, 2014, were provided to Kinectrics for the following major asset categories:

- Power Transformers
- Large Pad-mounted Transformers
- Standard Pad-Mounted Transformers
- Pole Top Transformers
- Poles
- Pad-Mounted Switchgear
- Underground Primary Cables

NPEI also monitors feeder performance through data collected by its Outage Management System. Feeder performance values are used in conjunction with asset health indices as key drivers for capital expenditure planning to identify feeders that require urgent attention.

NPEI engaged in its first customer survey in 2014 and intends to engage in a biannual customer survey going forward. NPEI also developed a written customer engagement plan in July 2014 and is currently in the process of implementing this plan. The engagement plan provides a process for NPEI to leverage feedback obtained from its customers as a key business driver and input to capital expenditure planning. Both the 2014 customer survey and engagement plan are included as appendices of this document.

The DSP also formalizes historical Capital Expenditure planning processes utilized by NPEI. Beyond asset management strategies influence on capital expenditure planning, other business conditions impact the mix and scope of capital investments. Capital investments for the period covered by this DSP are mapped according to the following project categories:

System Access: These are investments to support municipal development, regional development, and demand for new/upgraded connections. These include road relocation projects in partnership with land use authorities and expansions for customer connections or property development.

System Renewal: Investments categorized as system renewal are required to sustain existing operations maintaining an acceptable level of asset performance. System Renewal expenditures are based on the results of the 2014 Asset Condition Assessment report. The ACA report provides health indices for major asset categories which NPEI uses to prioritize asset replacements. In addition to the ACA, NPEI categorizes some of its programs as System Renewal based on identification of assets at end of life. An example of this is the kiosk replacement program where the holistic population of the asset base is at end of life.

System Service: These investments include upgrades and modifications to NPEI's distribution system to meet reliability expectations and provide future capacity. While these investments enhance NPEI's operational capabilities, they also typically result in distribution system loss reduction. The investments include deployment of new technologies to improve operational effectiveness.

General Plant: Investments in general plant support NPEI's capital expenditure plan. These investments are driven from the attached 2014 Fleet Assessment and 2014 IT Assessment.

A description of projects and programs associated with these categories is provided in greater detail in this document.

Cost Savings Expected Over Forecast Period

The capital programs and projects identified over the forecast period are generally expected to result in improvement in reliability and operational efficiency, and distribution system losses reduction. Continuing to improve system reliability while maintaining asset integrity has been a key focus of NPEI’s historical capital expenditures. This focus has been confirmed by feedback obtained through customer surveys and will continue to drive programs and projects identified in the forecast period.

Improved reliability will result from NPEI's ability to quickly react and respond during contingencies. Many of projects identified under the System Service category are designed to increase NPEI’s operational capability through the addition of feeder tie points and extension of main feeder infrastructure. Additionally, NPEI endeavours to implement technologies that enable remote response and automation to decrease overall response times during contingencies.

It is important to note that while the majority of NPEI’s capital expenditure focuses on system renewal, many of the projects within this category also contribute to improved reliability. Reconstruction of pole lines and underground facilities result in installations with increased capacity, improved sectionalizing capability, and the introduction of new technologies. New construction in residential areas are based on NPEI’s current standards which include covered conductor and insulated brackets in order to mitigate outages caused by tree contact. Elimination of small step-down transformers removes a point of failure from the system while reducing the overall loss footprint on the distribution system.

NPEI has integrated its Geographical Information System (GIS) to the Distribution Engineering Simulation Software (DESS) package. The GIS and DESS software platforms contain a model of NPEI’s entire distribution system allowing it to be used to support design. The DESS model also utilizes data from NPEI’s operational data store (ODS) providing the tools to perform feeder optimization studies. These studies support design and operation of the distribution system resulting in a reduction of system losses and support of REG connections.

NPEI has also successfully integrated its advanced meter infrastructure (AMI) to the InService Outage Management System (OMS). Real time reporting of outage and restoration notifications from meter to OMS provide instantaneous prediction of failed devices on the distribution system resulting in an improvement in response and restoration time. NPEI is building on its successes by introducing grid modernization strategies into station design and communication network deployment to achieve real time input of device status into the OMS. This will provide NPEI with real time operating control of the network and result in reduced window time for crews for tasks as protection feature blocking.

Distribution System Planning Period

NPEI's DSP has been prepared for the following period:

Historical Period				Bridge Year	Test Year	Forecast Period			
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019

Supporting Studies and Inputs

Several key studies and input documents support NPEI's asset management process and capital expenditure plan. The documents are included in the appendix and their utilization is further explained in this DSP. The supporting documents are as follows:

- 2014 Asset Condition Assessment (ACA) - Appendix E
- 2014 Feeder Reliability Assessment - Appendix C
- 2014 Load Forecast - Appendix K
- 2014 CDM Activity Summary - Appendix L
- 2014 IT Assessment - Appendix I
- 2014 Fleet Assessment - Appendix F
- 2014 NPEI Customer Engagement Plan - Appendix G
- 2014 NPEI Customer Engagement Baseline Report - Appendix H
- 2014 NPEI Customer Survey Report - Appendix D
- 2014 Grid Modernization Strategy - Appendix J

5.2.2 Coordinated Planning with Third Parties

The following outlines how NPEI has met the OEB's expectations for coordinating infrastructure planning with customers, the transmitter, other distributors, the Ontario Power Authority, and other third parties. As part of the renewed regulatory framework, the OEB has expanded the Cost of Service Distribution Rate Application filing with new requirements for a formalized DSP to demonstrate and document NPEI's coordinated planning and formal engagement with the following stakeholders and processes:

- Integrated Regional Resource Planning (IRRP) with the OPA
- Regional Infrastructure Planning (RIP) with Hydro One Networks Inc. (HONI)
- Renewable Energy Planning with the OPA
- Neighbouring LDC's
- Customer and Industry Stakeholder Engagement

NPEI is part of the Niagara Region in the Group 3 of Southern Ontario:

Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Figure 5 - 1: Map of Southern Ontario Planning Regions (Source: OPA)

5.2.2.1 Integrated Regional Resource Planning (IRRP) with OPA

On August 12th 2014, NPEI requested an update on the status of IRRP for Group 3 (Southern Ontario) from the OPA. An e-mail response dated August 13th was sent to NPEI from the OPA in response to this inquiry and is included in Appendix A. The response indicates: *"Niagara Peninsula Energy Inc. is part of Group 3 and the Niagara Region for regional planning purposes. At the present time neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has commenced for Niagara Peninsula's service territory, and planning may not commence until 2015 when the transmitter will kick off the needs screening process."*

5.2.2.2 Regional Infrastructure Planning (RIP) with HONI

On August 12th 2014, NPEI requested an update on the status of Regional Infrastructure Planning for Group 3 from Hydro One. A letter dated August 19th was sent to NPEI from Hydro One in response to this inquiry and is included in Appendix B. The letter indicates: *"the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the Niagara Region affecting the Niagara Peninsula Energy Region. I am expecting, as per the new process, that the regional planning for the Niagara Region may be initiated in 3rd or 4th quarter of 2015."*

5.2.2.3 Renewable Energy Generation Planning with OPA

NPEI is in regular communication with OPA regarding Renewable Energy Generation (REG) connections, conservation and demand management programs, and other OPA initiatives. NPEI has requested a letter of comment from the OPA related to REG planning on August 12th and is waiting for a response pending review of NPEI's DSP.

5.2.2.4 Neighbouring and Other LDCs

NPEI has a strategic partnership with neighbouring utilities known as the Niagara Erie Public Power Alliance (NEPPA). The NEPPA group holds annual meetings to discuss grid modernization strategies, best practices, and cost sharing initiatives. Most notably, the NEPPA group shared infrastructure during the recent Smart Meter implementation for the AMI, where towers and base stations to establish the communication network were shared between the seven member utilities:

- Niagara Peninsula Energy Inc.
- Fortis Inc.(Canadian Niagara Power)
- Grimsby Power Inc.
- Haldimand County Hydro Inc.
- Niagara-On-The-Lake Hydro Inc.
- Norfolk Power Inc.
- Welland Hydro Electric System Corp.

5.2.2.5 Customer and Stakeholder Engagement

Customer service is a core business function of NPEI, and commitment to excellence is a major focus within its day to day operations. Several options exist in which Customers can engage NPEI staff with concerns or questions they need addressed, whether directly or indirectly. Since the implementation of Smart Meter Technology, the Customers supply NPEI with crucial operational information. In the last few years, NPEI has made major investments in systems to aid staff in providing state of the art

Customers service. The most noteworthy, is implementation of the Outage Management System (OMS). The OMS is able to poll Smart Meters within its Service Territory and display the meters reporting an outage. Depending upon the number, the OMS compiles the information and predicts the possible point of failure. This provides operators with accurate information for the efficient dispatch of crews for timely power restoration, regardless of the size of the event.

During normal working hours NPEI has staff available to address customer requests, as related to billing, new service requests, REG inquiries, outage reporting, or project inquiries. Another option is the NPEI website, providing a means for Customers to leave comments or questions to appropriate staff, during or after normal working hours. Requests are reviewed by a manager or supervisor and distributed to appropriate Staff for follow-up. NPEI has provided the means for their Customers to interact, as conveniently as possible. NPEI also leverages social media outlets such as Twitter and Facebook to provide notification as another form of Customer engagement.

NPEI engages Customers prior to implementation of Major Projects within its Service Territory. The Technician managing the project delivers construction notices, to each customer and business affected, outlining project scope, and contact information. This typically occurs three weeks prior to the start date. Questions or concerns are addressed where practical, and layout adjustments are implemented. In certain circumstances, NPEI will host Townhall meetings when substantial civil works could impact Customers property or access.

NPEI participates with their municipal partners and fellow utility providers, in monthly Public Utility Committee (PUC) Meetings. Short and long term planning goals, of the various agencies, are shared in the group to aid in efficient planning and coordination between the agencies, as required. Participants include The Regional Municipality of Niagara, the City of Niagara Falls, the Township of Lincoln, the Township of West Lincoln, the Town of Fonthill, the Ministry of Transportation, The Ministry of Labor, Cogeco Cable, Enbridge Gas, Bell Telephone, and the Niagara Parks Commission. Minutes are kept by the various municipalities and are made Public. Relevant information is shared with appropriate staff to aid in planning, budgeting and scheduling.

5.2.3 **Performance Measurement for Continuous Improvement**

NPEI utilizes a number of performance based metrics as inputs to asset management and capital expenditure planning processes. The metrics provide an essential feedback mechanism to ensure that NPEI is maintaining alignment with NPEI's strategic business objectives.

NPEI utilizes 5 key performance metrics that provide input to its asset management and capital expenditure planning process:

1) Reliability Performance
2) Safety Performance
3) Customer Satisfaction
4) Regulatory Compliance
5) Asset Health Indices

5.2.3.1 Reliability Performance

NPEI monitors system reliability indices SAIDI, SAIFI, and CAIDI on a monthly basis. NPEI's outage management system (OMS) is the source of information for the 3 indices. Outage events are determined by the OMS based on the input of smart meter outage alarms and customer calls. The input of smart meter alarms provide a reliable start time for outage events as opposed to methods employed previously that relied on a customer's call. Upon receipt of a predicted outage, NPEI control room operators immediately dispatch field staff for investigation. Following restoration, crews identify the cause of the outage and restoration time on field based mobile devices. The restore time is compared to the restore notification from real time smart meter data and updated by NPEI operators. This process ensures the utmost accuracy in customer count, outage duration, and outage cause as related to service reliability indices.

Standard reports from NPEI's outage management system are available such that the overall service reliability indices can be summarized monthly. The indices are also summarized at the feeder level. Analysis of the indices allow NPEI to measure the success of operational and maintenance activities as well as whether capital expenditures in positively impacting system performance.

<u>Overall Performance Indices</u>

As required by the Ontario Energy Board's Electricity Reporting and Record Keeping requirements, the following indices are tracked and reported:

- SAIDI - System Average Interruption Duration Index:

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

- SAIFI - System Average Interruption Frequency Index:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

- CAIDI - Customer Average Interruption Duration Index:

$$\text{CAIDI} \quad \frac{\text{SAIDI}}{\text{SAIFI}}$$

Figure 5 - 3 and Figure 5 - 3 indicate the monthly trend of SAIDI from 2010 to 2013.

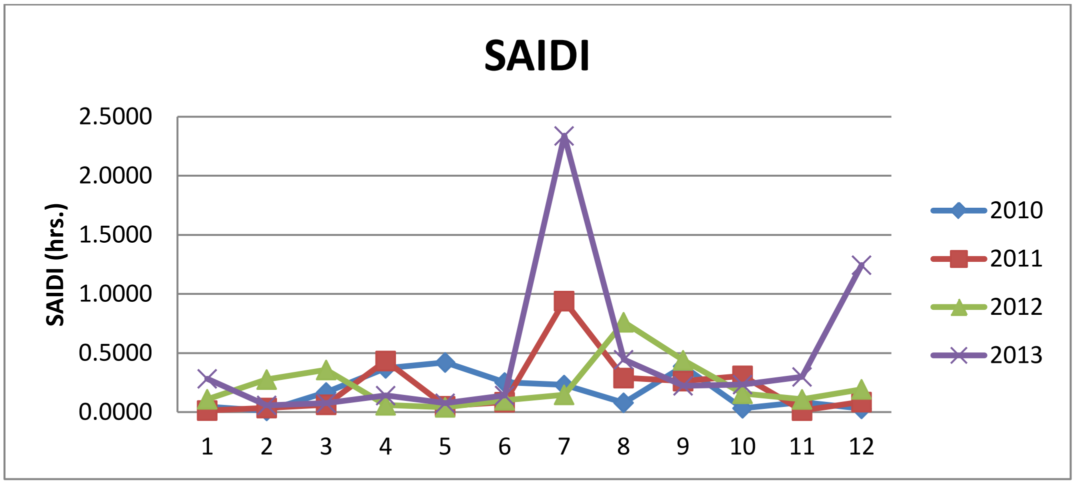


Figure 5 - 2: Monthly Trend of SAIDI from 2010 to 2013

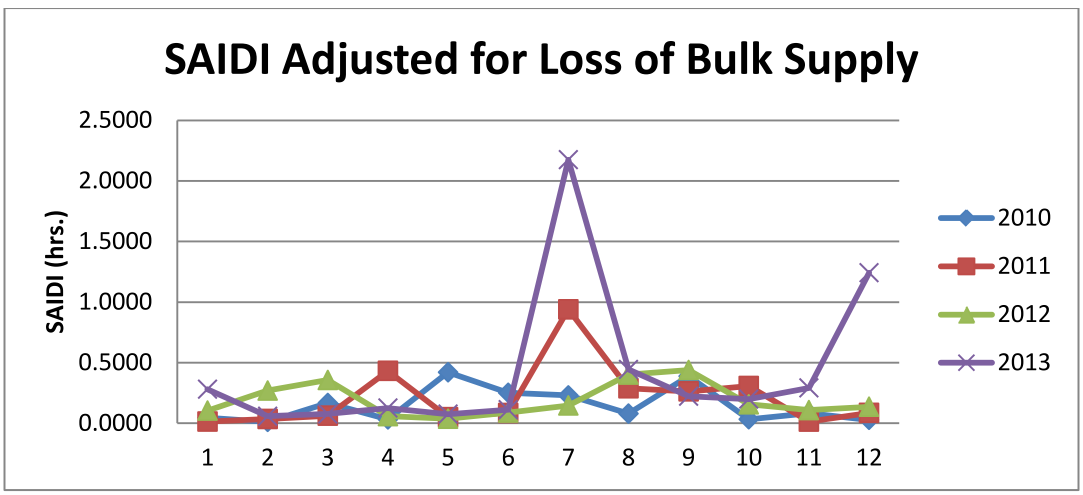


Figure 5 - 3: Monthly Trend of SAIDI from 2010 to 2013 (Excluding Loss of Supply)

Additionally, the year to year trend of SAIDI is depicted in Figure 5 - 4 and Figure 5 - 5.

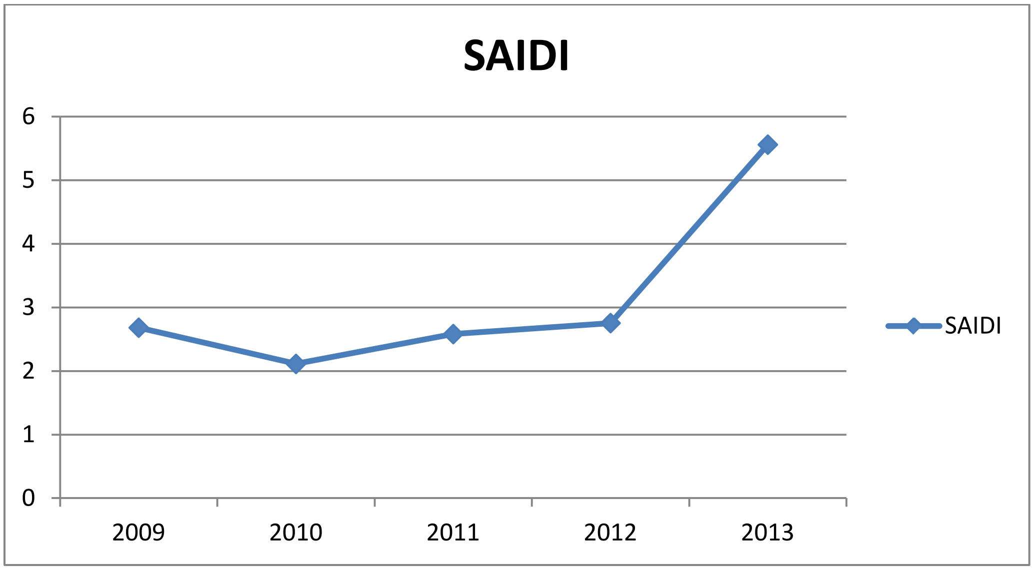


Figure 5 - 4: Annual Trend of SAIDI from 2009 to 2013

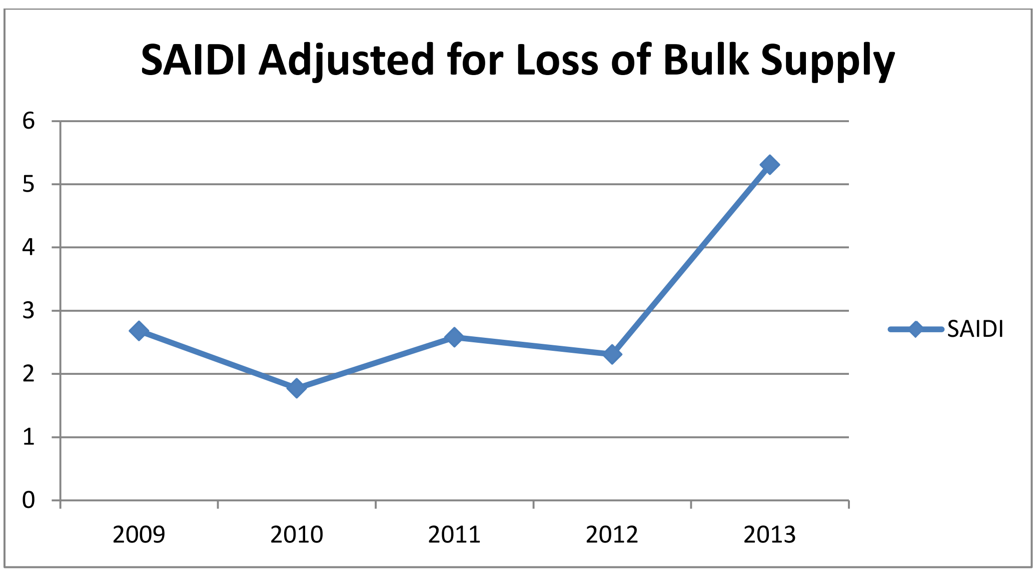


Figure 5 - 5: Annual Trend of SAIDI from 2009 to 2013 (Excluding Loss of Supply)

Figure 5 - 5 indicates that SAIDI is substantially higher in 2013 than in previous years. This is because of two separate extreme weather events that occurred in July and December of 2013.

In July of 2013, NPEI experienced a high heat weather event with extreme wind gusts, torrential rains, and a large quantity of lightning strikes. The event started the evening of Friday July 19th, 2013 and crews were affecting repairs throughout the weekend with accumulated damage repair costs of $180,423. Figure 5 - 6 demonstrates the customers that experienced an outage by hours elapsed:

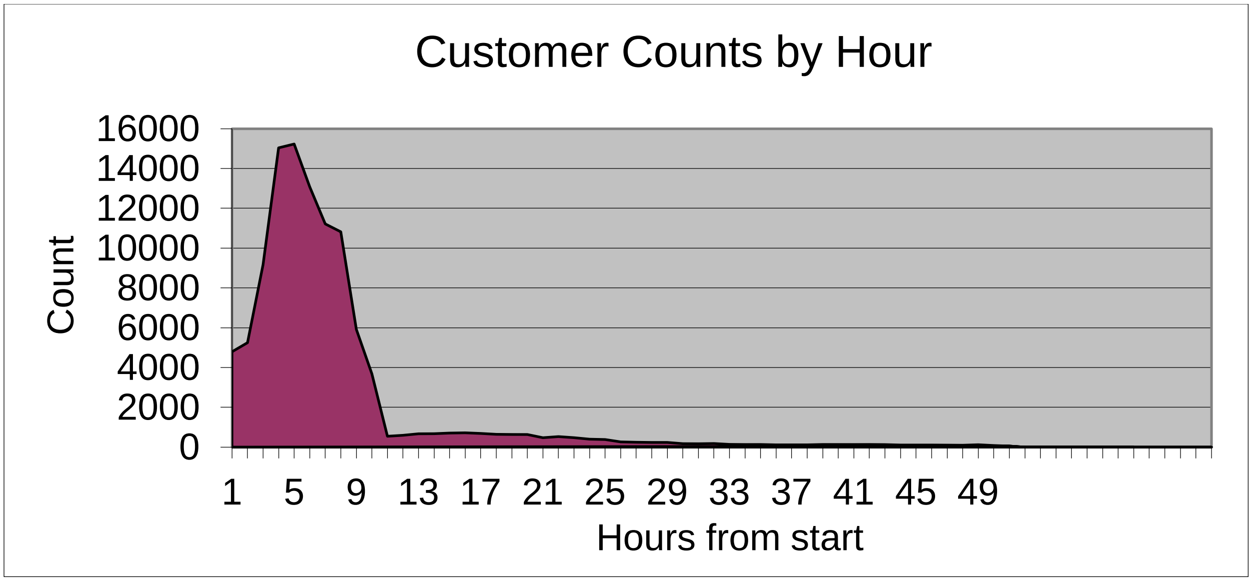


Figure 5 - 6: July 2013 Weather Event - Customers Affected by Hour

Table 5 - 1 summarizes the affected feeders and associated customer counts:

Table 5 - 1: July 2013 Weather Event - Customers Affected by Feeder

Feeder	Counts
Beamsville M1	4758
Beamsville M2	2471
Beamsville M4	63
Niagara West M2	2383
Niagara West M5	1260
Vineland F1	1768
Vineland F2	1901
Stanley M33	1880
Total	**16484**

In December 2013, NPEI experienced a freezing rain event which affected most of Southern Ontario. The event began on December 22nd and affected over 10,000 NPEI customers. Restoration efforts were not complete until the afternoon of December 24th.

Figure 5 - 7 demonstrates that with the removal of the impact of these two separate events and loss of bulk supply from the indices, NPEI's SAIDI is generally trending downwards:

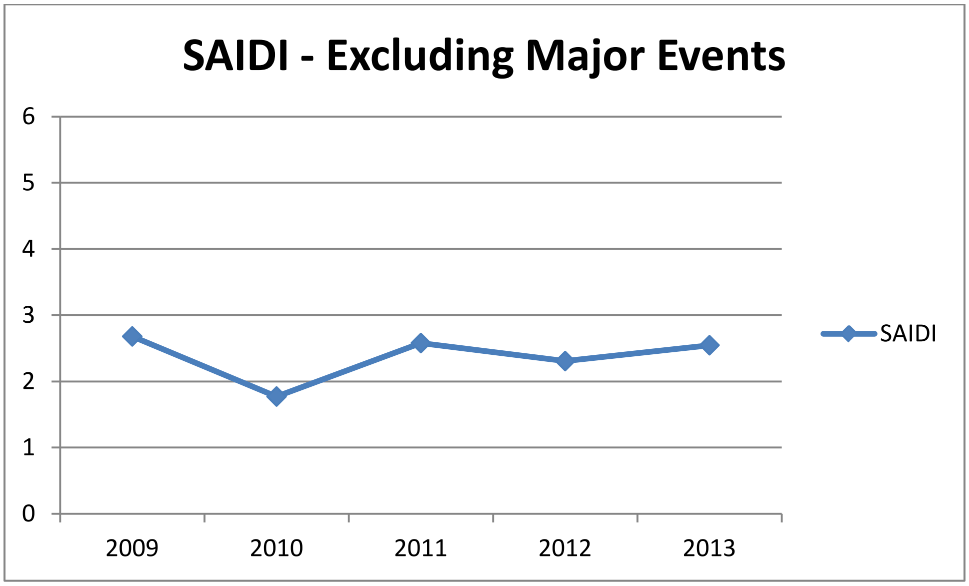


Figure 5 - 7: Annual Trend of SAIDI w/ Major Events Removed

Figure 5 - 8 and Figure 5 - 9 indicate the monthly trend of SAIFI from 2010 to 2013:

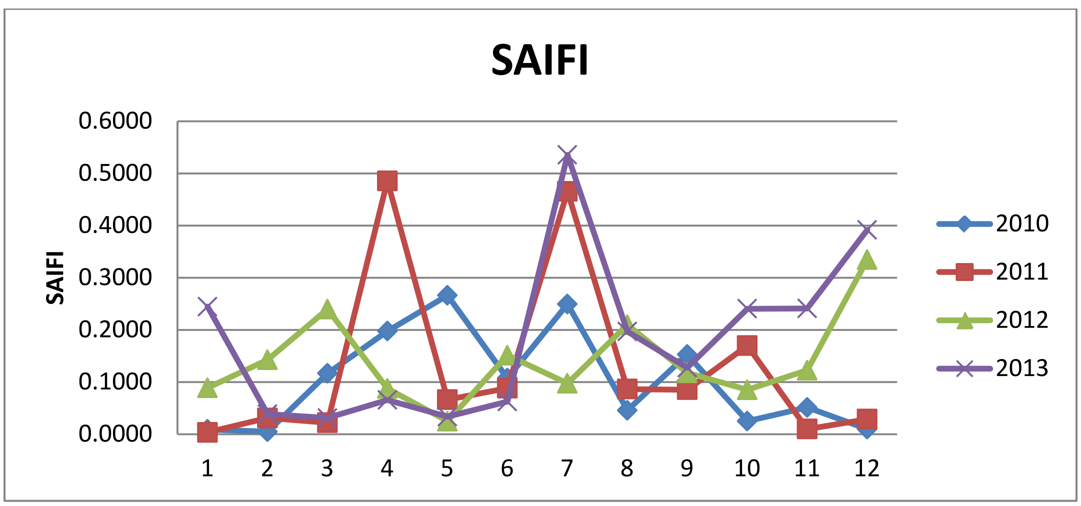
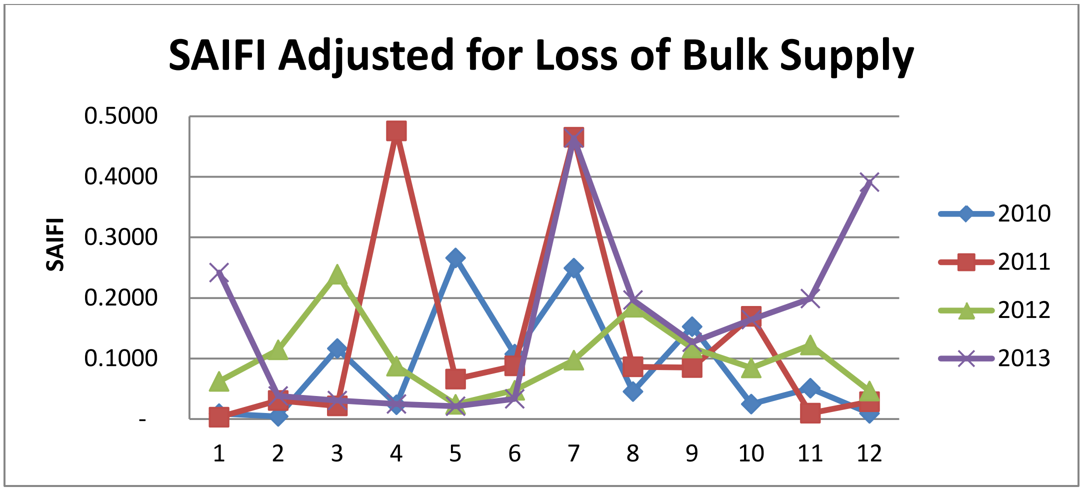
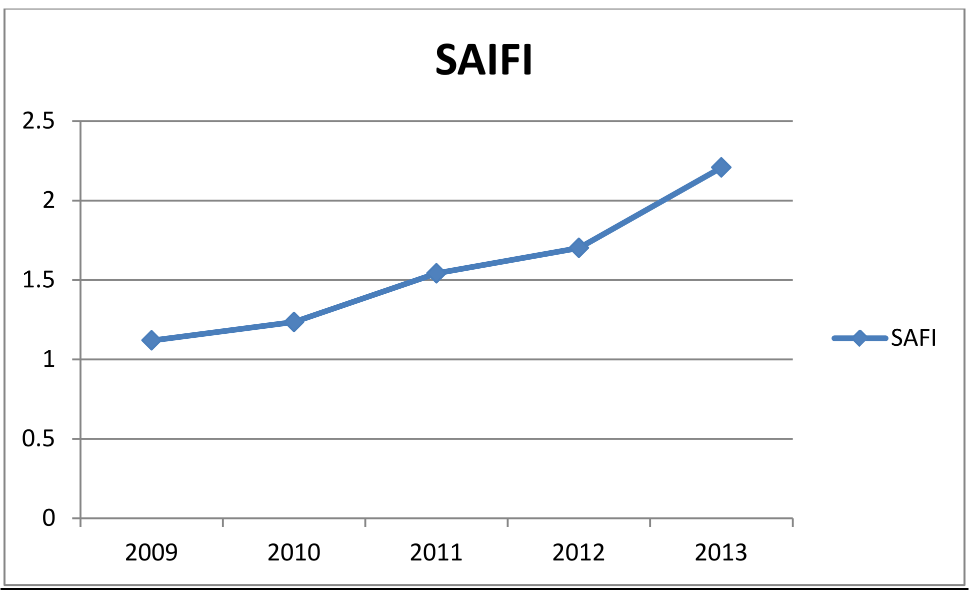


Figure 5 - 8: Monthly Trend of SAIFI from 2010 to 2013



<u>Figure 5 - 9: Monthly Trend of SAIFI from 2010 to 2013 (Excluding Loss of Supply)</u>

Additionally, the year to year trend of SAIFI is depicted in Figure 5 - 10 and Figure 5 - 11.



<u>Figure 5 - 10: Annual Trend of SAIFI from 2009 to 2013</u>

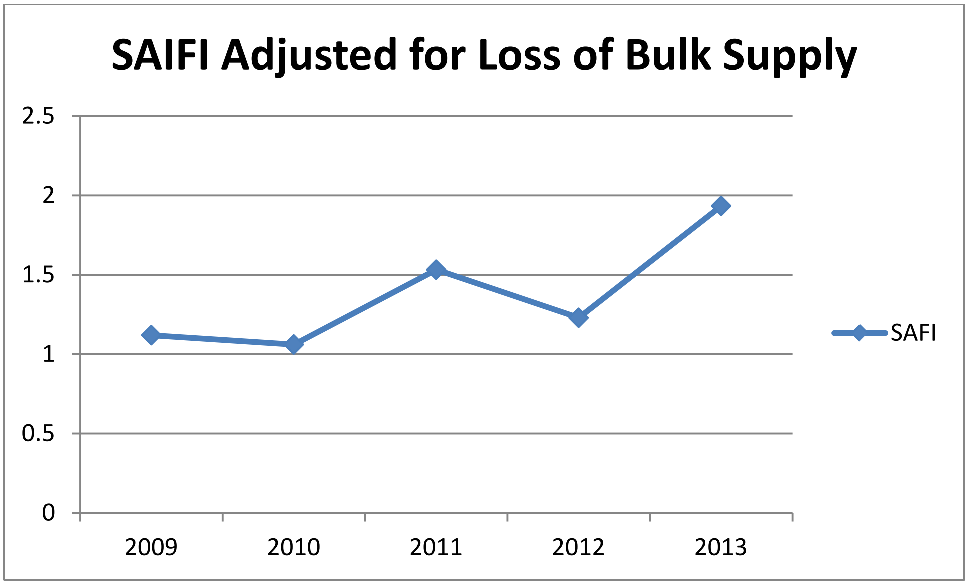


Figure 5 - 11: Annual Trend of SAIFI from 2009 to 2013 (Excluding Loss of Supply)

Figure 5 - 12 indicates SAFI with the removal of the impact of the 2 major weather events and loss of bulk supply from the indices:

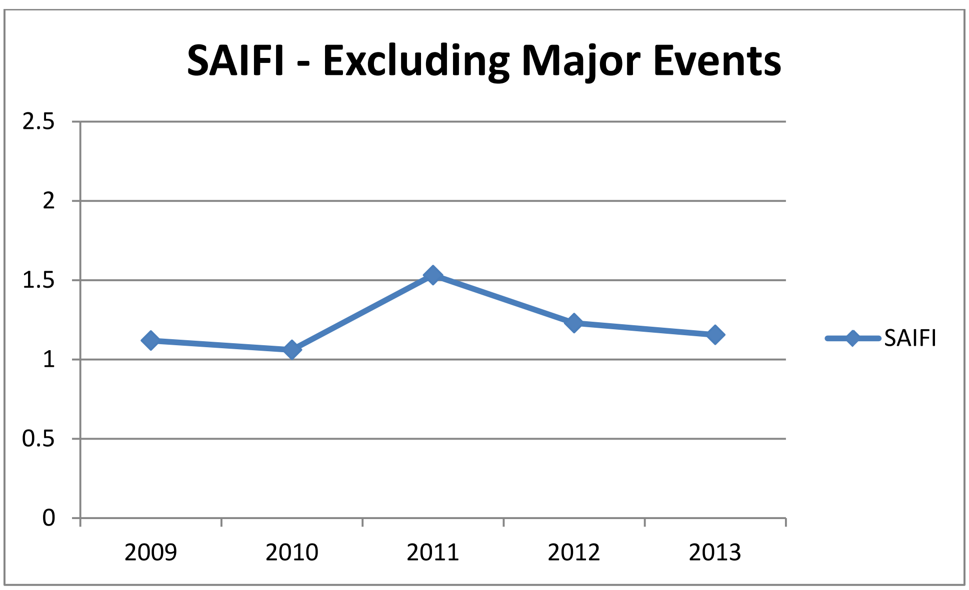


Figure 5 - 12: Annual Trend of SAIFI w/ Major Events Removed

Figure 5 - 13 and Figure 5 - 14 below indicate the monthly trend of CAIDI from 2010 to 2013:

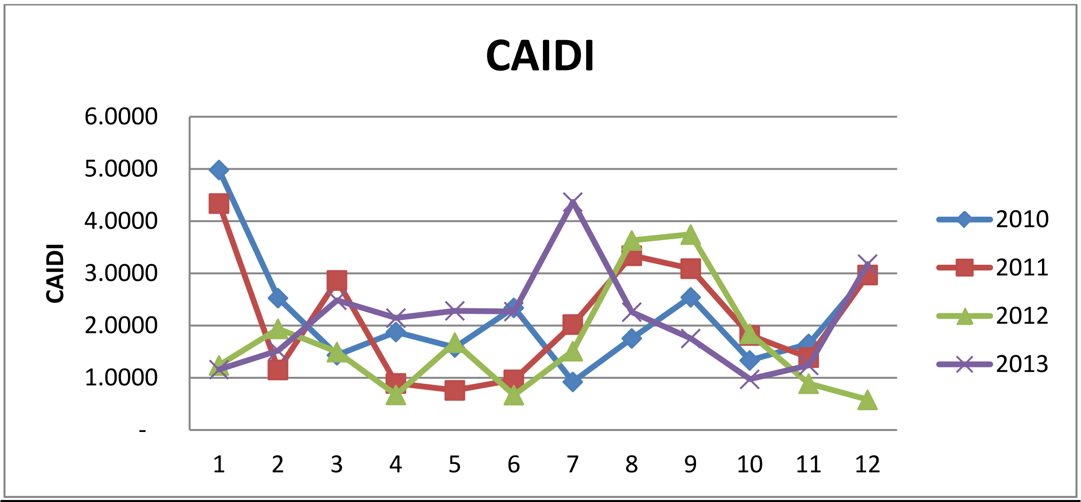


Figure 5 - 13: Monthly Trend of CAIDI from 2010 to 2013

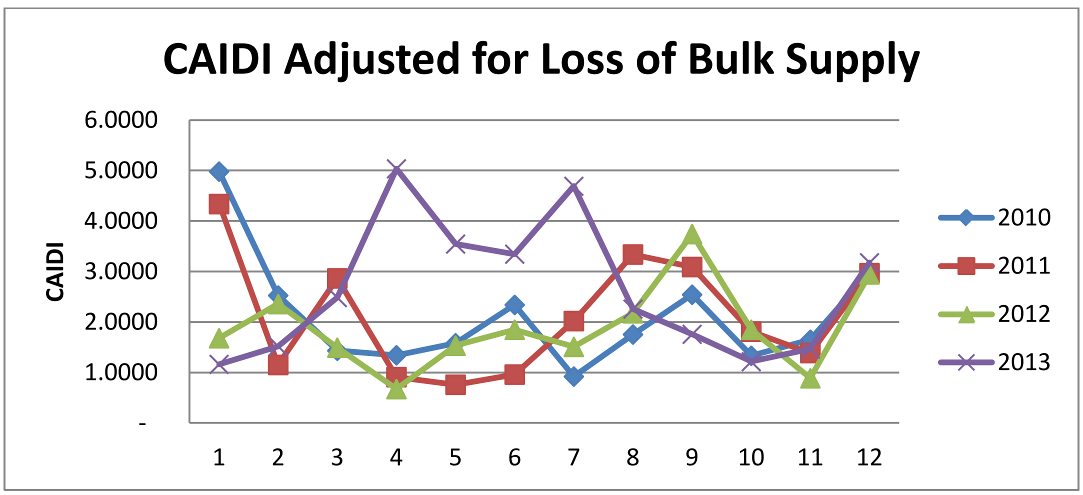


Figure 5 - 14: Monthly Trend of CAIDI from 2010 to 2013 (Excluding Loss of Supply)

Additionally, the year to year trend of CAIDI is depicted in Figure 5 - 13 and Figure 5 - 16.

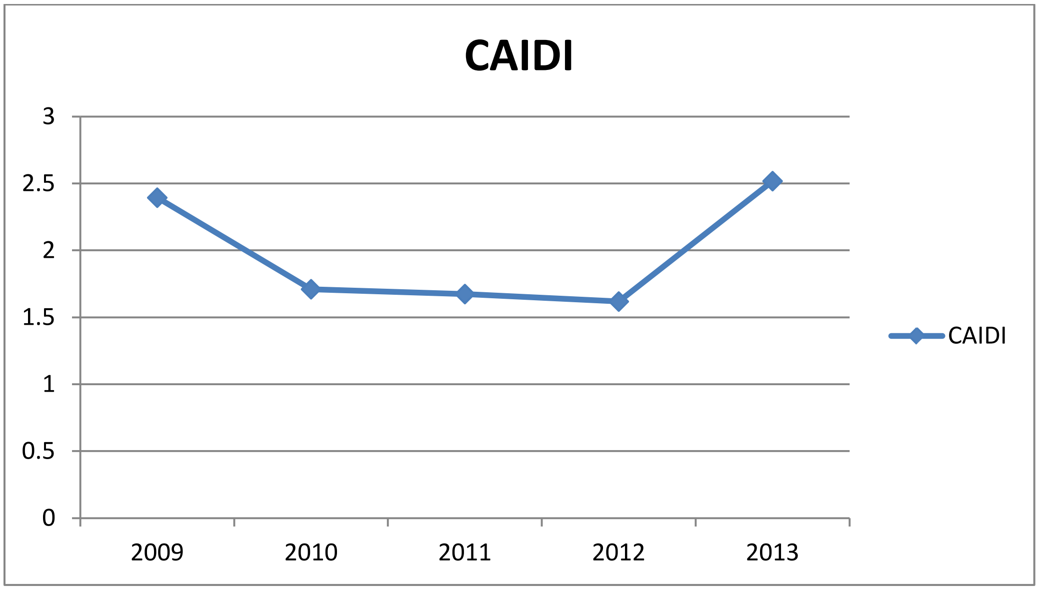


Figure 5 - 15: Annual Trend of CAIDI from 2009 to 2013

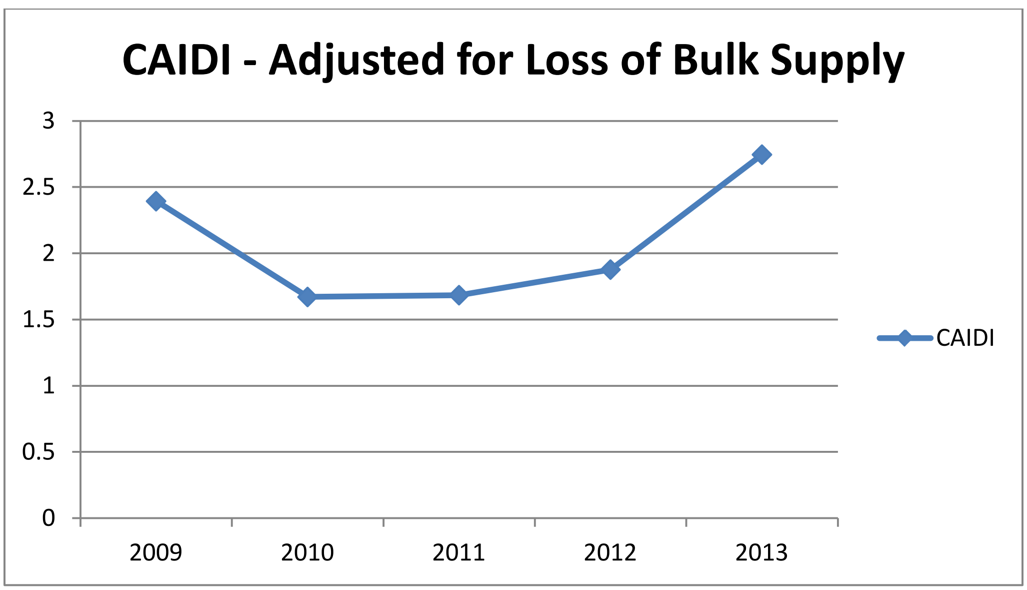


Figure 5 - 16: Annual Trend of CAIDI from 2009 to 2013 (Excluding Loss of Supply)

Figure 5 - 17 indicates CAIDI with the removal of the impact of the 2 major weather events and loss of bulk supply from the indices:

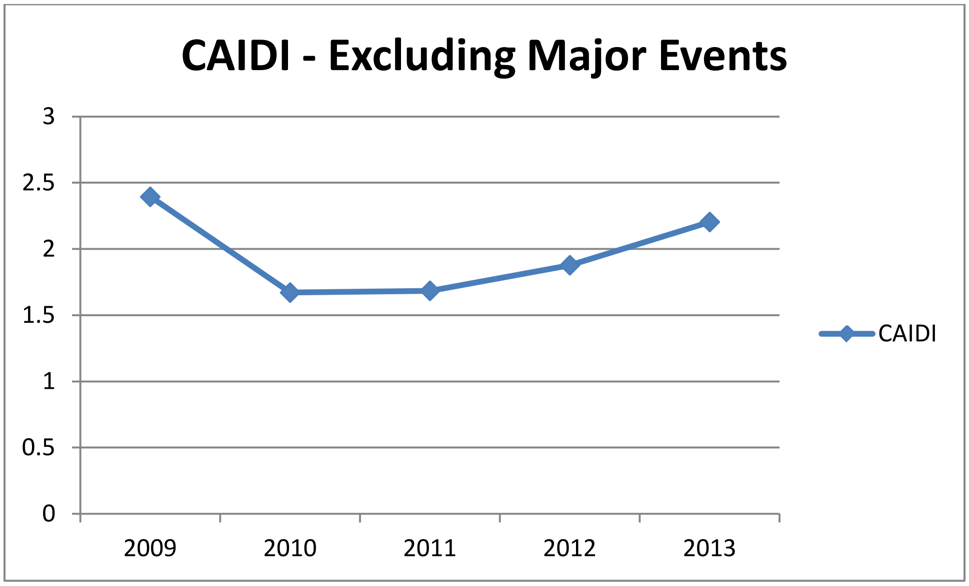


Figure 5 - 17: Annual Trend of CAIDI from 2009 to 2013 w/ Major Events Removed

Feeder Performance Indices

NPEI added greater formality to the process of monitoring feeder performance levels starting 2012. The feeder reliability indices, as well as the 10 best and 10 worst feeders, are shown in Appendix C. Prior to 2012, NPEI manually reviewed outage statistics to identify poor performing feeders. With the implementation of an outage management system that leverages AMI data for outage and restoration notification messages, NPEI is able to provide an accurate depiction of feeder performance.

The feeder reliability indices are reviewed annually to identify year over year trending in poor performance. Feeders identified as having recurring poor performance levels, that are not attributed to an externally driven event, are analysed through the asset management process. The asset management process assesses potential mitigation expenditures in order to determine feasibility.

5.2.3.2 Safety Performance

In early 2004 changes in regulation advanced public electrical safety with the approval and introduction of Ontario Regulation 22/04 addressing Electrical Distribution Safety. Ontario Regulation 22/04 - Electrical Distribution Safety establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. The regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service by NPEI.

The Electrical Safety Authority enforces regulation for licensed distributors in Ontario. In order to ensure compliance, the Electrical Safety Authority requires licensed distributors to engage in third party audits. NPEI arranges for third party audits annually to ensure compliance with the regulation. The table below summarizes audit findings for the period 2009 to 2013:

Table 5 - 2: ESA Audit Findings Summary 2010-2014

Audit Period Ending	Annual Compliance Audit		Due Diligence Inspection Audit		Total Findings
	Non Compliant	Needs Improvement	Non Compliant	Needs Improvement	
2010	1	0	0	0	1
2011	0	0	1	4	5
2012	0	0	0	2	2
2013	1	0	0	0	1
2014	1	0	0	1	2

NPEI reviews and responds to the Electrical Safety Authority regarding findings of non compliance or opportunity for improvement. NPEI implements action plans in order to remedy findings of non-compliance.

5.2.3.3 Customer Satisfaction

In June 2014, NPEI completed the first Customer Satisfaction Survey with the aid of Utility PULSE, included as an Appendix D. NPEI management staff have reviewed the results and will implement suggestions in future endeavours, where practical. An Engagement Index from the Survey indicated that respondents felt power reliability to be one of the most important factors in power delivery (cost, reliability, safety). Several wide spread outage events experienced by NPEI in 2013 has demonstrated that OMS predictions may be erroneous if traced back to a Distribution Station supplying several feeders. It can be difficult to determine a probable fault location due to the timing and number of meters reporting on multiple feeders.

As a natural extension of the OMS, NPEI has made grid modernization investments, since 2012, to pilot a wireless communication system utilizing Wi-max technology at the 1.8GHz frequency, reserved by Industry Canada for Electric Utility usage. 48-hour D.C. back-up systems and communication enabled electronic re-closers, have been installed at several rural Distribution Stations. With the installation of several towers and ruggedized base stations by Q4 2014, NPEI will have the ability to gather more information from the system during large, widespread outage events, on long rural feeders, to deploy Crews more efficiently which in turn should reduce outage duration. By reviewing the magnitude of current, on a per feeder basis, it becomes easier to narrow down the probability by feeder and phase. NPEI also has a program to upgrade aging hydraulic reclosers with electronic solid dielectric models, which will provide a gateway to more valuable information for outage restoration and distributed generation monitoring. The system will eventually expand in function to remotely operate switches, provide video surveillance at Transformer and Distribution Stations for Public Safety and vandalism prevention, and the future possibility of AMI backhaul.

5.2.3.4 Regulatory Compliance

NPEI adheres to Appendix C of the Distribution System Code (DSC) which specifies inspection requirements for LDC's. Inspection programs that are implemented to meet these requirements are:

- Annual pole and overhead equipment (5-year cycle)
- Annual pad-mounted equipment (5-year cycle)
- Monthly transformer and distribution stations
- Kiosk inspections (5-year cycle)
- Manhole and sidewalk vault inspections (5-year cycle)

The results of each of these cyclical inspection programs are captured in NPEI's GIS. Records are created in the GIS for each asset deficiency noted by the inspector. Standard reports summarize asset deficiencies such that they can be reviewed and prioritized for corrective action. Where immediate corrective action is required, work orders are issued to remedy the deficiency. Otherwise, the data is used as a direct input to the asset condition assessment (ACA) and/or asset management process (AMP) to support investment decisions related to system renewal.

5.2.3.5 Asset Health Indices

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:

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

where

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

With inputs:

CPS	Condition parameter score
WCP	Weight of condition parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-condition parameter score
WCPF	Weight of sub-condition parameter
β_n	Data availability coefficient for sub-condition parameter

The health indices of NPEI's key distribution assets and the trends of an asset category's health index profile provide insight into the impacts of system renewal initiatives. A decline in the overall Health Index of an asset class may indicate the need for additional system renewal activities such as pole replacements. Improvement in the Health Index of an asset class may be an indication of successful mitigation of asset degradation through renewal programs.

5.3 ASSET MANAGEMENT PROCESS

5.3.1 Asset Management Process Overview

5.3.1.1 Asset Management Process Detail

The Asset Management Process is the foundation for development of NPEI's business plan. Figure 5 - 18 depicts the high level process followed by NPEI with a description of the process as follows:

Needs Identification

There are 3 high level categories of inputs to the Needs Identification process: External Drivers, Internal Drivers, and Strategic Investments. Each of these are described below:

External Drivers

The majority of External Drivers feeding into the Needs Identification Process originate from:

- Regulatory - Accommodation of Distributed Generation
- Customer Demand - New / Upgraded Connections
- Municipal / Regional Initiatives - Road Relocations

These drivers typically result in projects that are non-discretionary in order to maintain compliance with the requirements of the Distribution System Code.

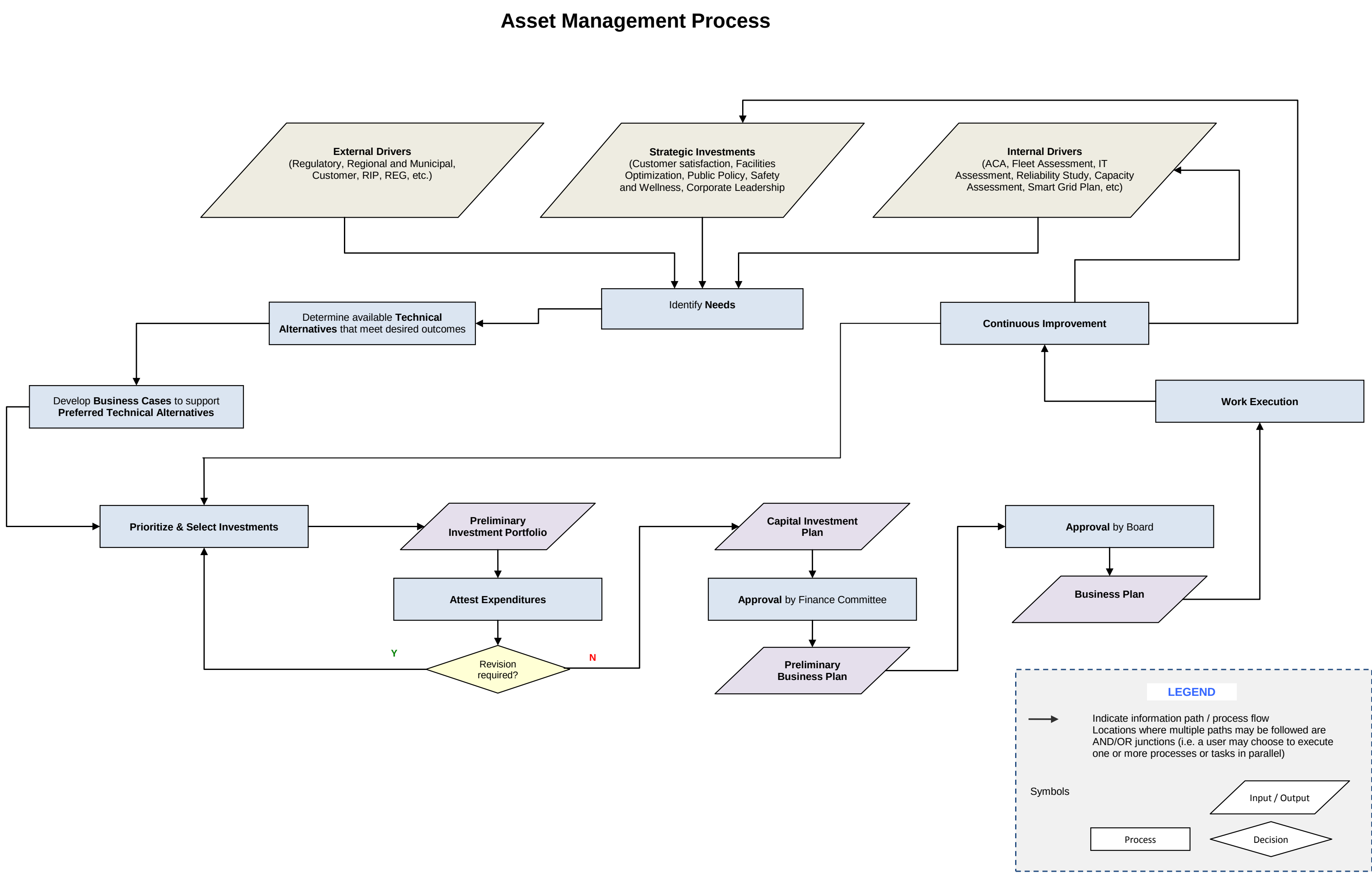


Figure 5 - 15: NPEI's Asset Management Process

Internal Drivers

Internal Drivers are typically the result of studies and inspection programs aimed at maintaining asset performance levels to applicable standards. The studies and inspection programs that result in internal drivers include:

- Asset Condition Assessment
- Pole Inspection Program
- Underground Equipment Inspection Program
- Manhole / Kiosk Inspection Program
- Feeder Reliability Metrics
- IT Assessment
- Fleet Assessment

Strategic Investments

Strategic Investments are identified through review of performance measurements for continuous improvement. These investments are identified to maintain alignment with NPEI's strategic objectives. Considerations to identify needs typically include:

- Reliability / Performance: Investments that maintain current performance levels or enhance reliability and reduce outage occurrence / duration.
- Safety: Investments that will mitigate hazards to workers and/or will improve public safety.
- Efficiency: Investments that will result in system loss reduction and/or improved operational response.
- Community Relations: Investments that will improve NPEI's presence in the community.

Technical Alternatives

Once needs are identified, technical alternatives to addressing the need are developed. The considerations given to development of each technical alternative include impacts on reliability, safety, efficiency, and community relations. Consideration is also given to the required timing, resource and material availability.

Each technical alternative identifies an outcome, high level project scope, and a high level estimate associated with implementation. The technical alternative also identifies whether external factors are driving the need. An example is a road relocation with an associated time constraint. These technical alternatives typically move directly into development of a business case and are prioritized based on the required timing.

The list of technical alternatives is maintained on a perpetual capital project prioritization list.

Business Cases

Business cases are developed for projects identified at the highest priority levels. The business case outlines the project scope and the expected outcome. The business case also identifies the cost associated with project execution, the category of investment, the evaluation criteria, and the associated business drivers.

NPEI's corporate business values and strategic objectives are fundamental to the drivers identified in each business case. It is imperative that the developed business case is in line with NPEI's vision and strategy and appropriately reflects the needs of the community and its customers.

Prioritize and Select Investments

Business cases are selected for execution based on priority. Business cases developed to address a need stemming from an external driver are prioritized based on deadlines and resource availability. These are typically customer, municipally, regionally, or regulatory driven.

Business cases based on internal drivers are prioritized based on the identified risk that results from asset or asset class condition assessment. The identified risk is balanced against resource availability to determine an appropriate timeline for execution. In some instances, both a strategic investment and internal driver are addressed through the implementation of a business case which will result in a higher level of prioritization.

Strategic Investment driven business cases are prioritized based on alignment to strategic objectives. Priority is based on the level of impact on: Reliability / Performance, Safety, Efficiency, and Community Relations.

Expenditure Attestation

The expenditure attestation process involves review of each proposed investment by NPEI senior management. This control measure ensures that the investment portfolio is appropriately aligned with NPEI's vision and strategic objectives. It also ensures that appropriate risk mitigation strategies are deployed within the investment portfolio.

The attestation process is iterative and allows senior management to request re-prioritization and selection of investments to achieve greater alignment to strategic objectives. Once a final investment portfolio is identified, it forms the capital business plan and becomes part of the annual capital and operating budget. The annual capital and operating budget are presented to the Finance Committee for review and approval.

Approval by Finance Committee / Board of Directors

NPEI's Finance Committee reviews the capital investment plan and consideration is given to:

- alignment with strategic goals
- mitigation of business risk
- impact on customers
- benchmark against historical expenditures

Upon approval of the capital investment plan, the capital and operating budgets are forwarded to the Board of Directors for review and approval. Once approved by the Board of Directors, the capital investment plan is moved to the work execution process.

Work Execution

The work execution plan considers project dependencies (project phasing), labour and material constraints, and externally driven deadlines. A work execution plan is presented to management staff in the Operations department at the onset of the business plan deployment.

Work execution progress is tracked by the Engineering Supervisor of Design, Purchasing Manager, and the Regional Operations Supervisors. Progress is tracked in a centralized database designed to produce exception reporting (areas of work execution at risk).

The exception reports are reviewed by project stakeholders at bi-weekly meetings to ensure adherence to the plan. Exception reports track deviation from plan for use by continuous improvement processes at the completion of projects.

Continuous Improvement

Exception reports are reviewed at a project close out meeting following the work execution phase. The meeting captures lessons learned and suggested opportunities for improvement moving forward. Opportunities for improvement are reviewed by senior management and typically result in implementation of a corrective action.

Several factors can play a role in the success of the work execution plan. The introduction of external drivers to the process is dynamic and can trigger modification to the prioritization process. NPEI works in partnership with municipal and regional entities to achieve project alignment. This being the case, there are instances where alignment is not possible and infrastructure project timing impacts execution of NPEI's business plan.

Other factors such as resource availability, economic conditions, and regulatory changes can determine the success of plan execution. Such influences may not only lead to changing prioritization of investments but may also lead to redefinition of corporate business values and strategic objectives.

5.3.1.2 Supporting Inputs and Outputs Related to Capital Expenditure Planning

Information resulting from the following studies, assessments, and plans were used to prepare the capital expenditure plan.

2014 Asset Condition Assessment

The 2014 Asset Condition Assessment was completed by an independent consultant, Kinectrics Inc., and involved assessing the condition of assets in major asset categories of NPEI's distribution system. The following categories were included in the ACA study:

- Power Transformers
- Large Pad-mounted Transformers
- Pole-top Transformers

- Wood Poles
- Standard Pad-mounted Transformers
- Pad-mounted Switchgear
- Underground Primary Cables

Using data from NPEI's GIS, inspection results, and maintenance activities, the ACA provides a quantitative assessment of asset condition using a health index approach. A 20-year flagged for action plan was also determined for each asset category included in the study. This ACA is an update of the original ACA produced for NPEI in 2009. ACA study details are provided in Appendix E.

2014 Fleet Sustainment Plan

The 2014 Fleet Sustainment Plan results are provided in Appendix F. Currently NPEI has a fleet of 61 vehicles that range in age from 1992 to 2013. Of the 61 vehicles, 37 are greater than 3 tons and 24 are less than 3 tons. Currently, only one small vehicle is older than eight years and five large vehicles are greater than 15 years.

The Fleet Sustainment study analyzed existing vehicles based on inputs such as age and kilometres travelled. Each vehicle is given a weighted score which is used to prioritize replacements. The analysis results indicate the capital expenditures required to maintain a fleet compliment based on replacement of end of life vehicles.

2014 IT Assessment

In 2014, NPEI completed an IT Assessment to ensure that technology solutions are aligned with strategic business objectives. The IT Assessment is included in Appendix I of this document. The assessment considers alignment to the objectives of customer focus, operational effectiveness, public policy responsiveness, and financial performance.

The IT Assessment identifies forecasted capital expenditures from 2015 to 2019 for hardware and software components necessary to achieve NPEI's technology deployment strategy.

Feeder Reliability Assessment

Since 2012, NPEI has leveraged OMS data to assess the performance of distribution feeders. Individual feeder performance indices are provided in Appendix C of this document. Trends in poor performing feeders are identified by analysing year to year performance which drives capital expenditures in the system service category. The data is used to identify opportunities to reduce feeder exposure, improve sectionalizing capability, and to add supply redundancy to better reliability.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of Service Area Features

NPEI's electrical distribution system services the municipalities and townships of Fonthill, Niagara Falls, Lincoln and West Lincoln. As the local electrical distribution company, NPEI services approximately 51,452 residential, general service, and street-light customers (December 2013).

The following map illustrates the extent of NPEI's service area:

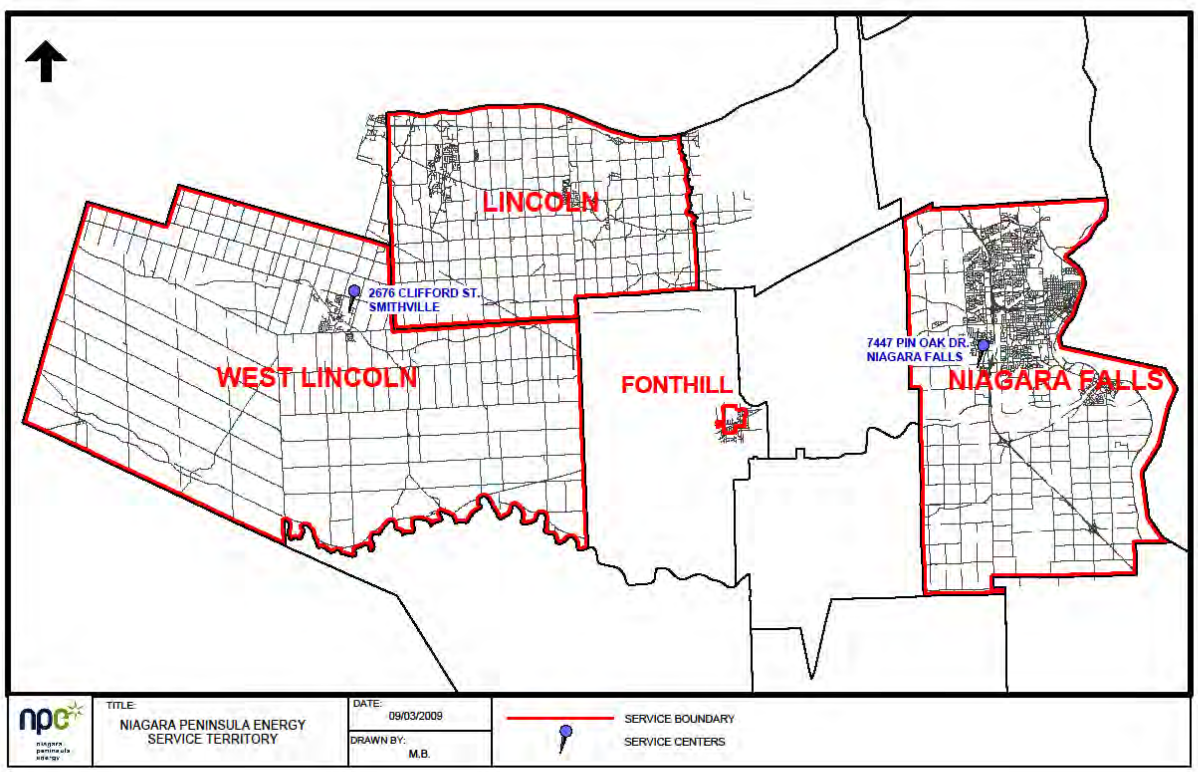


Figure 5 - 14: Service Area Map

The Western portion of NPEI's service territory is substantially rural. The distribution system covers the limits of Lincoln and West Lincoln townships. Approximately 15,350 (December 2013) customers are serviced in Lincoln and West Lincoln. Electricity is supplied to customers in these areas via the following substations:

Table 5 - 3: Lincoln / West Lincoln - Transformer Stations

Transformer Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Beamsville TS	Hydro One	115kV	27.6kV	4
Niagara West TS	Niagara West Transformer Corporation	230kV	27.6kV	3
Vineland DS	Hydro One	115kV	27.6kV	2

There are five distribution substations connected to the 27.6kV system to service customers from the 8.32kV distributions system:

Table 5 - 4: Lincoln / West Lincoln - Distribution Stations

Distribution Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Bismark DS	Hydro One	27.6kV	8.32kV	3
Campden DS	Niagara Peninsula Energy	27.6kV	8.32kV	2
Greenlane DS	Niagara Peninsula Energy	27.6kV	8.32kV	2
Jordan DS	Niagara Peninsula Energy	27.6kV	8.32kV	2
Smithville DS	Niagara Peninsula Energy	27.6kV	8.32kV	2

The Eastern portion of NPEI's service territory has a significant urban component with a high traffic tourism core. The Southern and Western portions of the service territory are primarily rural. Approximately 34,726 customers (December 2013) are serviced in the City of Niagara Falls. Electricity is supplied to customers in the city via the following substations:

Table 5 - 5: Niagara Falls - Transformer Stations

Transformer Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Murray TS	Hydro One	115kV	13.8kV	16
Kalar TS	Niagara Peninsula Energy	115kV	13.8kV	8
Stanley TS	Hydro One	115kV	13.8kV	10

There are eleven distribution substations connected to the 13.8kV system to service customers from the 4.16kV distributions system:

Table 5 - 6: Niagara Falls - Distribution Stations

Municipal Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Allendale MS (#8)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Armoury MS (#1)	Niagara Peninsula Energy	13.8kV	4.16kV	4
Dorchester MS (#23)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Drummond MS (#10)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Lewis MS (#7)	Niagara Peninsula Energy	13.8kV	4.16kV	4
Margaret MS (#14)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Ontario MS (#3)	Niagara Peninsula Energy	13.8kV	4.16kV	2
Park MS (#6)	Niagara Peninsula Energy	13.8kV	4.16kV	4
Pew MS (#22)	Niagara Peninsula Energy	13.8kV	4.16kV	2
Swayze MS (#18)	Niagara Peninsula Energy	13.8kV	4.16kV	3
Virginia MS (#17)	Niagara Peninsula Energy	13.8kV	4.16kV	4

At the center of NPEI's service territory is the village of Fonthill. The distribution system covers the limits of Fonthill, servicing approximately 1,376 (December 2013) customers. Electricity is supplied to customers in these areas via the following substations:

Table 5 - 7: Fonthill - Transformer Stations

Transformer Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Allanburg TS	Hydro One	115kV	27.6kV	2

There are two distribution substations connected to the 27.6kV system to service customers from the 4.16kV distributions system:

Table 5 - 8: Fonthill - Distribution Stations

Distribution Substation	Operated By	Primary Voltage	Secondary Voltage	Feeder Count
Pelham DS	Niagara Peninsula Energy	27.6kV	4.16kV	2
Station DS	Niagara Peninsula Energy	27.6kV	4.16kV	3

The following table summarizes features and associated data related to NPEI's service area:

Table 5 - 9: NPEI Distribution System Features

System Feature	Data
2013 Peak Demand	265.8 MW
Number of Customers	51,689
Service Territory	827 sq. km
Transformer Stations Supplying NPEI	7
Number of TS Feeders	48
Distribution Stations Supplying NPEI	18
Number of DS Feeders	51
Overhead Line Route Length	1,459 km
Underground Cable Route Length	519 km

5.3.2.2 NPEI Asset Profile

NPEI's key distribution asset categories are identified in Table 5 - 10. The table includes population, average age, and health index distribution for the asset category.

Table 5 - 10: Asset Categories, Health Index, and Average Age

Asset Category		Population	Sample Size (% of Population)	Average Age (NA = Not Available)	Average Health Index	Health Index Distribution				
						Very Poor (≤30%)	Poor (>30 - 50%)	Fair (>50 - 70%)	Good (>70 - 85%)	Very Good (> 85%)
Power Transformers		19	100.0%	23	86%	0%	5%	0%	37%	58%
Large Pad-mounted Transformers		66	95.5%	17	93%	0%	0%	3%	13%	84%
Pole-top Transformers		6683	99.5%	22	92%	< 1%	3%	3%	11%	82%
Wood Poles		24546	96.2%	30	95%	< 1%	3%	2%	6%	88%
Standard Pad-mounted Transformers		2682	100.0%	15	96%	< 1%	< 1%	< 1%	2%	97%
Pad-mounted Switchgear		74	81.1%	NA	81%	0%	2%	52%	5%	42%
Underground Cables (data in conductor-km)	**Main Feeder**	48	68.8%	10	98%	0%	0%	0%	8%	92%
	Distribution	427	66.0%	16	94%	< 1%	2%	3%	6%	89%

Figure 5 - 20, shown below, indicates that power transformers, wood poles, and pole-top transformers have the highest percentage of units in poor condition. These health indexes directly tie to several system renewal capital expenditures aimed at asset replacement.

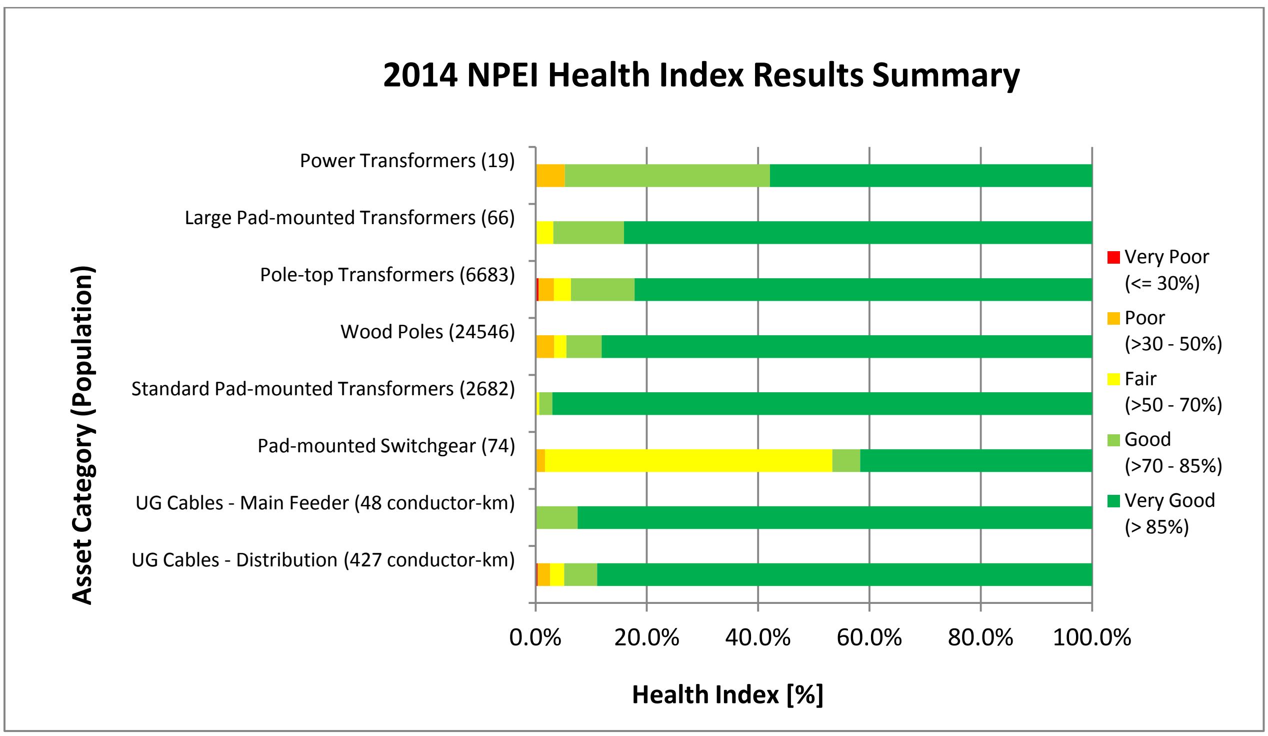


Figure 5 - 18: 2014 Health Index Distribution

5.3.2.3 Assessment of System Capacity

Capacity to Connect Load

NPEI's distribution system is supplied from seven separate transformer stations. All are owned and operated by Hydro One with the exception of Niagara West TS and Kalar TS. Niagara West TS is owned by the Niagara West Transformer Corporation. Kalar TS is owned and operated by NPEI.

The following table summarizes the nameplate rating of each of these transformer stations and the peak load from 2013.

Table 5 - 11: Transformer Station Capacity

Delivery Point	Service Area	Rating (MVA)	Maximum Load MVA (2013)
Allanburg TS	Fonthill	9.6	5.6
Beamsville TS	Lincoln/West Lincoln	25/41.6	18.6
Kalar TS	Niagara Falls	22.5/30/37.5	38.6
Murray TS	Niagara Falls	67.5/90/112.5	101.1
Niagara West TS	Lincoln/West Lincoln	40/53.2/63.4	48.3
Stanley TS	Niagara Falls	40/53.3/66.7	64.0
Vineland DS	Lincoln/West Lincoln	15/20/25	18.9

The Fonthill area is serviced by 2 feeders from Allanburg TS. One of the feeders normally supplies all of the load. A backup feeder is available from the TS during contingencies. Historical peak load values have not encroached on the available capacity from the Allanburg TS supply feeders.

The Lincoln and West Lincoln areas are serviced by Beamsville TS, Niagara West TS, and Vineland DS. Niagara Peninsula Energy and Grimsby Power Inc. both utilize the Beamsville TS and Niagara West TS supply points. Historical peak load values are within the nameplate rating capacity at first stage cooling for each of the available supply points. Load transfer capability exists between the 3 supply points to manage load growth resulting in an overall availability of capacity.

The Niagara Falls area is serviced by Kalar TS, Murray TS, and Stanley TS. Historical peak demand on Murray TS is within the second stage cooling rating. The historical peak load on Stanley TS is approaching the second stage cooling nameplate rating. Both of these transformer stations are owned and operated by Hydro One. Historical peak demand on Kalar TS is at the second stage cooling rating of the station. Kalar TS is owned and operated by NPEI. Load transfer capability exists between the 3 transformer stations in the Niagara Falls area to manage available capacity. Kalar TS was commissioned in 2004 and was designed with the capability of adding a second switchgear lineup. Installation of the second lineup would result in an additional 37.5 MVA capacity at the second stage cooling rating. Niagara Peninsula Energy does not anticipate the addition of the second lineup in the 2015 to 2019 forecast period, however, external drivers could accelerate its necessity.

5.3.3 Asset Lifecycle Optimization Policy

NPEI's asset management strategies focus on maximizing the service life of distribution assets at the lowest lifecycle cost of ownership. NPEI utilizes cyclical inspection programs that align with the requirements of Appendix C of the DSC as input to the Asset Condition Assessment (ACA):

Table 5 - 12: Inspection Cycles

Asset Category	Activity Type	Description	Frequency
Power Transformers	Inspection	Visual Inspection	Monthly
	Testing	DGA, Oil Analysis, Furan	Annually
	Maintenance	Electrical Integrity Tests, Surface Refinishing	Every 3 Years
Large Pad-mounted Transformers	Testing	DGA, Oil Analysis, Furan	Annually
	Inspection	Visual, Infrared, Ultrasonic	Every 5 Years
	Maintenance	Surface Refinishing	Result from Visual Insp.
Pole-Top Transformers	Inspection	Visual Inspection	Every 5 Years
Wood Poles	Inspection / Maintenance	Visual Inspection, Treatment	Every 5 Years
Standard Pad-mounted Transformers	Inspection	Visual, Infrared, Ultrasonic	Every 5 Years
	Maintenance	Surface Refinishing	Result from Visual Insp.
Pad-mounted Switchgear	Inspection	Visual, Infrared, Ultrasonic	Every 5 Years
	Maintenance	Surface Refinishing	Result from Visual Insp.
Underground Cables	Inspection	Visual, Infrared, Ultrasonic	Every 5 Years
Kiosk Enclosures	Inspection	Visual	Every 5 Years
Manholes / Vaults	Inspection	Visual	Every 5 Years

Inspection and testing results are reviewed by NPEI engineering staff and resulting deficiency records are associated with assets in the GIS. Deficiencies that require immediate corrective action are remedied through issuance of a work order. The remaining deficiencies are prioritized based on the likely-hood of asset failure and the outcome associated with the failure. For example, a pole identified as "replace in 1 to 5 years" with a high consequence of failure will rank higher than a pole identified as "replace immediate" with a low consequence of failure.

Assets Flagged for Action

Figure 5 - 21 illustrates the 20 year "flagged for action" plan that resulted from the 2014 ACA. This plan is the basis for NPEI's system renewal based investments for assets with both proactive and reactive replacement strategies.

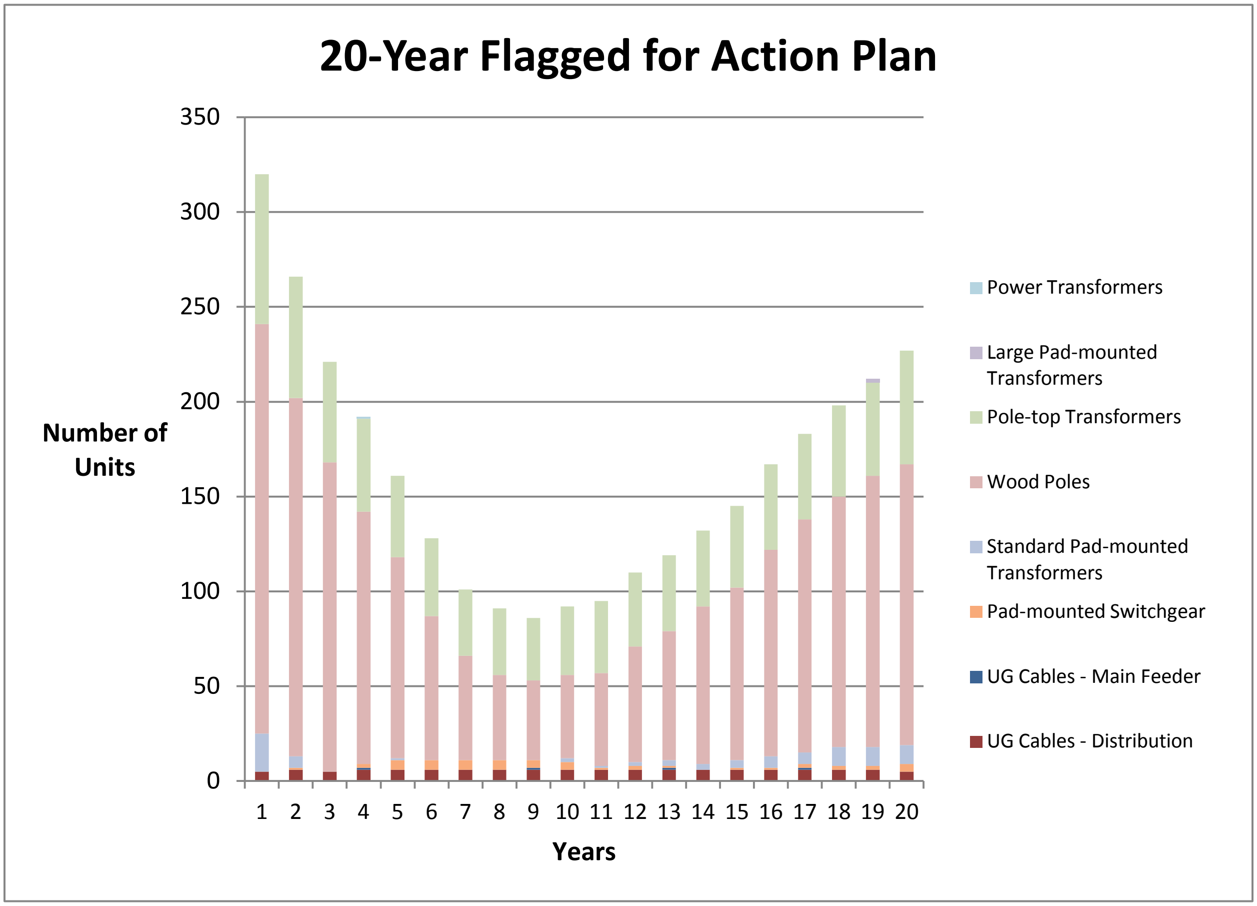


Figure 5 - 19: 20 Year Levelized Flagged for Action Plan

Asset categories are managed by either proactive or reactive replacements. Table 5 - 13 summarizes the asset management strategies for each category. Assets that have a low consequence of failure vs. a high cost of replacement are generally managed through a reactive approach.

Table 5 - 13: Asset Management Strategy by Category

Asset Category	Replacement Strategy
Power Transformers	Proactive
Large Pad-mounted Transformers	Proactive/Reactive
Pole-Top Transformers	Reactive
Wood Poles	Proactive/Reactive
Standard Pad-mounted Transformers	Proactive/Reactive
Pad-mounted Switchgear	Proactive
Underground Cables	Proactive
Kiosk Enclosures	Proactive

Assets that have a high consequence of failure such as station power transformers, poles, switchgear, etc. are managed through proactive replacement programs. The levelized flagged for action plan identifies the annual quantities of asset that require attention to keep pace with assets at end of service life. The annual quantities are the basis for the identified annual expenditure levels in the capital program for the forecast period.

For example, the levelized flagged for action plan indicates that approximately 216 poles should be replaced in 2015. In structuring the pole replacement strategy for 2015, NPEI reviewed the prioritized list of pole integrity deficiencies resulting from cyclical inspections. Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life and where system capacity and loss reduction benefits can also be realized. The balance of prioritized poles is scheduled for change out under the recurring project for pole replacements.

Flagged for Action Considerations

There are several options available to NPEI to manage assets that have been flagged for action. These are:

- Replacement
- Refurbishment/retrofit
- Run to failure strategy

For certain assets such as power transformers, a proactive replacement strategy is utilized. This is based on the fact that the asset is a critical component necessary to maintain the security and reliability of NPEI's supply. The consequence of asset failure outweighs the cost associated with replacement.

In some situations, refurbishment is a lower cost alternative to replacement and can mitigate the risk and likelihood of asset failure. The decision to refurbish an asset vs. replacement is made at various levels where it is identified that the total lifecycle cost of the asset can be minimized. For example, for pad-mounted transformers, the inspector will identify whether the condition of the enclosure is such that it can be re-furbished. As indicated in Table 5 - 12, NPEI refinishes pad-mounted equipment annually as part of cyclical maintenance programs.

Many of the inspection programs also include basic maintenance components such as the pole inspection program. During the pole inspection process, pole treatment is applied to extend the life of the asset. NPEI utilizes the services of qualified power-line contractors to perform apparatus inspection which also permits basic rehabilitation of installations. The pole inspection process also includes replacement of conductor guards, guy guards, and grounding repair to maintain safe operation of the asset.

In some cases, a run to failure strategy is utilized resulting in a reactive replacement strategy. An asset is run to failure when the replacement cost does not outweigh the consequence of failure. In these cases, NPEI has an appropriate level of resource availability to manage the replacement effort in a timely manner.

5.4 Capital Expenditure Plan

5.4.1 Summary

NPEI's Capital Expenditure Plan is divided into four investment categories as identified in the Chapter 5 filing requirements: System Access, System Renewal, System Service, and General Plant. The asset management process shown in Figure 5 - 18 describes the steps followed to build the capital expenditure plan. Each need is driven by internal drivers, external drivers, or NPEI's strategic business objectives. Technical alternatives to address each need are developed and analysed. The most appropriate technical alternative to address each need is selected and used to build a business case and associated capital expenditure. The business cases are prioritized in each investment category to determine the timing of project execution.

The following information summarizes the Capital Expenditure plan in accordance with Chapter 5 filing requirements:

Ability to Connect New Load Customers

In the West Lincoln / Lincoln area of NPEI's service territory, there is significant capacity at the transformer station level to accommodate expected load growth. Niagara West TS was constructed in 2004 (owned by Niagara West Transformer Corporation) and was constructed primarily to alleviate capacity constraints at Beamsville TS. Beamsville TS is Hydro One owned and the station power transformers were replaced with new units in 2009. Vineland DS has 2 power transformer units that supply a single feeder each with 25% peak load capacity available.

Historical and forecast capital expenditures in the West Lincoln / Lincoln area include expansion of the 27.6kV system to alleviate capacity constraints on the 8.32kV system. The 8.32kV stations have been stabilized by refurbishment. Transfer of some load to the 27.6kV system and load balancing has resulted in current peak load levels at the 8.32kV distribution stations to remain below 75% of capacity.

In the Fonthill area, NPEI introduced a redundant supply in 2009 providing ample capacity on the 27.6kV system. Both municipal stations with primary distribution at the 4.16kV level have been refurbished. Each station operates with a peak load at less than 65% of capacity. The Station Street DS power transformer is at end of life and is scheduled for replacement in the 2018 Capital Program.

The Niagara Falls service area has capacity available at Murray TS on the 13.8kV system. There is also significant load transfer capability between all three TS points which allows load transfer to manage load growth. Similar to the West Lincoln / Lincoln area, historical and forecast capital expenditures have included expansion of the 13.8kV system to alleviate load from the 4.16kV municipal stations. The municipal stations operate with a peak load at less than 75% of nameplate capacity. The forecast capital expenditures include conversion of loads to the 13.8kV system in advance of elimination of municipal substations which are at end of life and / or have access impediments.

Forecast Capital Expenditures

Table 5 - 14 summarizes NPEI's planned capital expenditures for the forecast period 2015 to 2019.

Table 5 - 14: Forecast Capital Expenditures

CATEGORY	Forecast				
	2015	2016	2017	2018	2019
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*
System Access	2,429	2,249	1,821	1,933	1,663
System Renewal	6,383	4,161	5,889	7,301	7,223
System Service	926	3,760	2,449	769	1,330
General Plant	1,447	1,434	1,352	1,204	1,311
TOTAL EXPENDITURE	**11,185**	**11,605**	**11,511**	**11,207**	**11,528**

System Access Investments

System Access based investments account for approximately 18% of the overall capital program. The majority of the forecasted investments in this category are based on historical requirements to permit:

- connecting new residential and commercial load
- expansion of the distribution system to accommodate new development
- coordination with municipal and regional partners on infrastructure improvement projects

System Access investments generally occur due to external drivers and are prioritized based on timelines outside of NPEI's control. A substantial portion of capital expenditure in the System Access category is an allotment to support municipal and regional infrastructure projects. The estimated annual capital expenditure for these projects are based on historical levels.

System Renewal Investments

System Renewal based investments account for approximately 54% of capital expenditures in the forecast period. The majority of investments in this category are based on the results of the asset condition assessment report. Two major programs are the basis for the majority of system renewal investments: the pole replacement program and kiosk 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.

In addition to the pole replacement program which covers single pole changes, there are areas of the distribution system in which the quantity of poles at end of life are concentrated. In these situations, a wholesale rebuild of the area to current day standards provides more benefit than individual pole changes. Several of the projects throughout the forecast period are based on concentrated areas of deteriorated poles.

In the Western portion of NPEI's service territory, there are several locations serviced by pole mounted step down transformers based on the extent of a previous voltage conversion. In many of this situations, deteriorated poles and pole attachments are concentrated. Starting in 2018, NPEI will begin the process of converting areas of highest priority to 27.6kV, eliminating the step down transformer, resulting in downstream distribution to current standards. In addition to replacing assets at end of life, other benefits such as loss reduction may be realized. NPEI's loss factor has decreased from 1.0560 in the 2011 COS rate application to 1.0478 in the 2015 COS rate application.

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 10 to 15 kiosks.

NPEI’s asset condition assessment has identified that there are several residential subdivisions in the Niagara Falls area with underground primary cable beyond end of life. The associated secondary distribution cable is of the same vintage as the primary cable. Starting in 2017, NPEI will initiate a program to install civil works to support replacement of primary and secondary conductors in the future. The cable will be run to failure at which time new cable will be installed as a sustainment expenditure. This is possible because the identified subdivisions all consist of loop fed distribution.

System Service Investments

Approximately 16% of NPEI's forecast capital expenditures are in the system service category. Throughout the forecast period, there are several projects that have been selected to improve reliability and system efficiency through line extensions to add redundancy to the distribution system. These line extension projects are designed to add operational flexibility by introducing main feeder tie points into the system. This expands redundancy within the distribution system and allows NPEI to load balance for efficiency.

Included in the System Service category is a capital program for replacement of switchgear units. There are approximately 75 switchgear units on NPEI's system concentrated in the downtown and tourism core of Niagara Falls. Under the program new switchgear are of a dead-front design and constructed with stainless steel components, contributing a benefit to overall system reliability and safety.

NPEI, also has a program designed to modernize the electrical distribution system. As outlined in NPEI's Grid Modernization Plan, NPEI is deploying new technology designed to enable communication with endpoint devices and to secure substations with the implementation of DC backup systems. The program positions the distribution system with technologically advance control points to permit distributed automation initiatives in the future.

General Plant

General plant investments represent approximately 12% of NPEI's forecast capital expenditures. The expenditures are related to assets that are not part of the distribution system including buildings, IT infrastructure, vehicles, tools, and equipment.

NPEI identified software and hardware requirements using its 2014 IT Assessment results. The IT assessment identifies hardware and software expenditures in the forecast period. The identified investments build upon existing systems to improve business processes and accommodate new business requirements in line with NPEI's strategic objectives.

NPEI has identified fleet purchasing requirements using its 2014 Fleet Assessment results. The fleet assessment identifies large and small vehicles that arrive at end of life in the forecast period and the associated replacement cost. NPEI's capital expenditures related to fleet are designed to maintain the current compliment and functional capability.

Material Projects

All material capital projects proposed by NPEI for 2014 and 2015 are listed in the table below:

Table 5 - 15: Material Capital Expenditures by Investment Category for the Bridge Year and Test Year

Material Projects	2014 Bridge Year	2015 Test Year
System Access		
Subdivisions	400,000	587,004
Line Relocation due to Municipal Requirements < Materiality	539,910	500,000
Demand based system reinforcements for new commercial services	1,410,778	1,007,500
Niagara Parks Commission		818,905
System Renewal		
Station #22 North of Pew		507,139
Station #22 South of Pew		143,724
Station #8	252,037	
12-M-6 Replacement	372,631	
Dorchester-Garden St to McMillan	362,018	
UG Primary Weightman Bridge	701,810	
3-M-28, 3-M-26, 3-M-29	417,731	
Crawford Street Rebuild	516,557	282,324
Frederica Street Rebuild		676,144
Fallsview Blvd -Ferry/Robinson	332,173	
Jordan Rd-Red Maple to QEW	397,516	
Jordan Phase II		449,324
Wholesale Meter Replacement	300,000	
OH to UG Rolling Acres Phase I	768,694	570,500
OH line rebuilds - 6 streets	516,513	

System Sustainment/Minor Betterments	400,000	680,000
Replace poles identified with limited structural integrity	778,702	431,729
Replacement of Submersibles & Kiosks with EFD switches and posi-tects	624,457	647,029
Replacement of Transformers with >50PPM PCB Content	566,479	495,104
NWTC Metering		289,605
Willodell Rebuild		310,710
Willoughby Dr. Extension		383,293
Willoughby Drive		372,191
System Service		
Smart meters	1,903,089	
MIST meters		143,150
Switchgear replacement program	110,057	250,002
King Street 27.6 kV	112,554	114,460
Wi-Max Project	227,500	215,000
General Plant		
Building	1,500,485	44,000
Computer Hardware	297,040	240,248
Computer Software	498,710	368,740
Vehicles	672,000	698,878
General Equipment	299,000	95,627

Influence of the Regional Planning Process CapEx Plan

The Regional Infrastructure Planning Process and Integrated Regional Resource Planning Process are in their infancy and do not impact NPEI's Capital Expenditure Plan at this time.

Customer Engagement

In June 2014,NPEI developed a 2014-2015 customer engagement plan which is included as Appendix G of this document. The engagement plan is designed to meet the OEB's Chapter 5 Customer Engagement Requirements and to contribute to the achievement of a Customer Focus Outcome. Key aspects of the plan are:

1. Education and Information to Customers
2. Customer Consultation Work
3. Service Territory Stakeholders Consultation Work
4. Participation in Consultation with the OPA and HONI
5. Consultation Topics

The first Customer Engagement Baseline Report documents activities conducted by NPEI to date related to the implementation of the customer engagement plan. This report is included in Appendix H of this document. The Baseline Report consists of a description of 2014 NPEI customer education, engagement, information and technical assistance activities current to June 30, 2014. This includes information on:

- Current customer education and information practices date (e.g., customer views needs/preferences/priorities)
- Customer consultation (e.g., inquiries, comments and complaints monitoring, surveying and direct engagement)
- Stakeholder consultation (e.g., regular meetings with local municipalities)
- OPA and HONI consultation (e.g., correspondence related to regional planning activities)

In conjunction with implementation of the Customer Engagement Plan, NPEI has implemented a biannual Customer Satisfaction Survey beginning in May 2014. NPEI retained UtilityPulse to conduct the customer satisfaction survey. A summary of the survey results is included in Appendix D of this document. NPEI used the results of customer engagement surveys to re-evaluate strategic business objectives and their influence on strategic investments.

System Development

Expansion of the 27.6kV and 13.8kV main feeder distribution systems are aimed at improving reliability, stabilizing capacity, and reducing the overall distribution system loss component. Expansion of these systems also extend NPEI's back-feed capability to improve restoration times during contingencies. Grid sectionalizing devices are incorporated into expansion plans to permit optimization of feeder loading. The devices also provide additional system protection elements to reduce overall feeder exposure during contingencies.

NPEI's historical and forecast expenditures have targeted distribution substations that will remain a key component of the system beyond 2019. These stations are being stabilized with upgraded transformation, protection systems, and backup DC power systems. Where distribution systems are at end of life in conjunction with the supplying distribution station, voltage conversion projects are part of the capital expenditure plan. Voltage conversions, where cost feasible, renew assets at end of life and contribute to the elimination of station equipment such as power transformers that are approaching end of life.

Grid Modernization Strategy

A portion of NPEI's forecast capital expenditures are focused on grid modernization. NPEI's Grid Modernization Strategy has been updated for 2014 and is included in Appendix J. Grid modernization investments include:

- Upgrading archaic electromechanical devices to modern electronics with communication provisions;
- Establishing a communications network to remotely monitor and control all new electronic devices;
- Automate key electronic devices and systems.

A multi-year grid modernization program has been implemented starting in 2012 focused on implementation of a secure, licensed wireless network to communication with endpoint devices. Since 2012, distribution substations have been outfitted with protection elements that are compatible with the new wireless communication network. Point to point licenses have been acquired through Industry Canada based on NPEI's phased approach to deployment of wireless infrastructure. Distribution Stations that are removed from the availability of wired communication mediums were targeted in the early phases of the program for wireless deployment. Wireless communication with these remote locations provide operational efficiencies during planned and unplanned events by:

- eliminating crew drive time for control actions
- providing real time status to NPEI's control center
- providing real time fault reporting to NPEI's engineering staff
- enabling distribution automation initiatives

The program also focuses on securing NPEI's distribution system by providing 24 hour visibility of critical assets. As stations are upgraded, data concentration devices are deployed to provide backhaul of critical data to NPEI's control room. The deployment incorporates DC backup systems capable of providing 48 hours of standby supply during contingencies. This allows NPEI to maintain security, visibility and control of assets in all situations.

The program incorporates DC backup systems and remote communication with intelligent field based at strategic locations on the downstream distribution systems once distribution substation deployment is complete.

5.4.2 Capital Expenditure Planning Process Overview

The objectives of NPEI's capital expenditure planning process is to address the needs resulting from internal drivers, external drivers, and strategic business objectives.

NPEI develops technical alternatives to address an investment need by using GIS data, engineering standard designs, and distribution engineering analysis software. The high level objective of engineering analysis in developing a technical alternative is to:

- Determine the impact on system efficiency
- Determine the impact on system operations
- Determine the impact on system capacity
- Determine the cost of implementation

Technical alternatives to address an investment need are evaluated against 4 key criteria which tie directly to NPEI's strategic business objectives:

- Reliability / Performance: The selected technical alternative should maintain or enhance baseline distribution system performance and improve reliability. Both strategic business objectives and customer feedback align to these key criteria.
- Efficiency: Technical alternatives must include some aspect of distribution system operational efficiency. Selected projects typically improve NPEI's operational effectiveness during contingencies. Projects may also contribute to a reduction in system losses.

- Safety: All capital projects selected for execution focus on improving public and worker safety. Selected alternatives focus on implementation of improved standards, increased clearance, and reduced exposure to hazards.
- Community Relations / Regulatory: In evaluating technical alternatives, an objective is to achieve an improvement related to NPEI's presence in the community. This may be through partnership with municipal / regional entities, the addition of capacity to accommodate new connections, or to improve aesthetics of NPEI plant.

Once the appropriate technical alternative is selected to address a particular need, a business case is developed. The business case identifies the high level project scope, anticipated implementation expenditure, evaluation criteria and drivers.

NPEI's engineering department maintains the list of business cases on a running project register. The project register ranks projects based on:

- deadlines stemming from an external driver
- risk related to asset condition
- alignment with strategic business objectives (4 key criteria)
- resource availability

Annually, the engineering department prepares an investment portfolio based on priority ranking in the project register. The investment portfolio is the basis for the Capital Expenditure Plan.

5.4.3 System Capability Assessment for Renewable Energy Generation

5.4.3.1 FIT Connections - Historical and Forecast

By the end of 2013, NPEI reviewed 158 pre-FIT consultation forms for a total capacity of 82.1 MW as summarized in the following table:

Table 5 - 16: FIT Connections - Historical

Request Year	# of Requests	Total Capacity (kW)
2010 Total	25	14,195
2011 Total	71	32,302
2012 Total	31	29,928
2013 Total	31	5,655
Grand Total	**158**	**82,080**

Under FIT 1.0, 17 contracts were awarded by the OPA and processed by NPEI. The following table summarizes the contracts and associated capacity by area:

Table 5 - 17: FIT Connections by Service Area

Region	# of Contracts	Capacity (kW)
Lincoln/West Lincoln Total	13	11,875
Niagara Falls Total	4	598
Grand Total	**17**	**12,473**

Beyond FIT 1.0, there have been no contracts awarded by the OPA (for FIT 2.1 and FIT 3.0) due to two high level transmission system constraints.

In the Niagara Falls service area, Murray TS, Kalar TS, and Stanley TS are connected to the same 115kV transmission system with constraints. This system is owned and operated by Hydro One Networks Inc. The 115kV system supplying these delivery points does not have the availability of short circuit capacity to accommodate connection of additional FIT projects. In the Fonthill, Lincoln, and West Lincoln areas, Allanburg TS, Beamsville TS, and Vineland DS connect to the same 115kV transmission system as the Niagara Falls transformer stations. These delivery points also do not have do not have any remaining short circuit capacity.

The remaining transformer station servicing the Lincoln and West Lincoln areas, Niagara West Transformer Station, is owned and operated by Niagara West Transformer Corporation (NWTC). This station also does not have any available short circuit capacity. NWTC is currently implementing upgrades to the TS to provide additional short circuit capacity which will enable connection of one FIT 1.0 project at 10MW. The upgrades are expected to permit future connection of FIT projects.

The following table summarizes the historical and forecast connection of FIT projects for the Lincoln / West Lincoln area:

Table 5 - 18: FIT Connection Forecast - Lincoln / West Lincoln

Connection Year	# of Connections	Connected Capacity (kW)
2010 Total	1	24
2011 Total	3	461
2012 Total	2	350
2013 Total	2	290
2014 Total	2	10,100
2015 Total	1	-
2016 Total	2	367
2017 Total	2	367
2018 Total	2	367
2019 Total	2	367
Grand Total	**21**	**12,693**

In 2015, NPEI does not anticipate any FIT connections due to transmission system constraints. Both Hydro One Networks Inc. and Niagara West Transformer Corporation have indicated that projects are underway to alleviate the short circuit limitations impacting REG connection availability. The forecast for the period 2016 to 2019 is based on the assumption that these transmission system constraints will be removed and OPA FIT program offerings will continue. The forecasted installed capacity is based on the historical average from the years 2011 through 2013 when projects were connected under FIT 1.0. A large 10MW wind project was connected in 2014 and has been removed from the historical average used for the forecast projection. This is based on the fact that there will be a saturation of wind deployment in the area due to a large 230MW project slated for connection to the transmission system in the area.

In the Niagara Falls area there were a limited number of connected projects under FIT 1.0. The historical and forecast FIT connected projects are summarized in the following table:

Table 5 - 19: FIT Connection Forecast - Niagara Falls

Connection Year	# of Connections	Connected Capacity (kW)
2010	0	-
2011	0	-
2012	1	23
2013	0	-
2014	2	225
2015	0	-
2016	1	60
2017	0	-
2018	1	60
2019	0	-
Total	**5**	**368**

Again, in 2015, NPEI does not anticipate any FIT connections due to transmission system constraints. Assuming that these constraints are removed beyond 2015, NPEI expects a small addition of REG capacity based on historical values.

5.4.3.2 microFit Connections – Historical and Forecast

NPEI connected 294 microFIT installations between 2010 and 2013 with a total installed capacity of approximately 2.7 MW.

In the Lincoln / West Lincoln area, NPEI connected 208 microFIT installations during the period 2010 to 2013. The following table summarizes the historical and forecast microFIT connections in the Lincoln / West Lincoln area:

Table 5 - 20: microFIT Connection Forecast - Lincoln / West Lincoln

Year	Transformer Station	# of Connections	Capacity (kW)
2010	Beamsville TS	7	56
2011	Beamsville TS	44	424
2012	Beamsville TS	23	213
2013	Beamsville TS	23	204

2014	Beamsville TS	30	280
2015	Beamsville TS	30	280
2016	Beamsville TS	30	280
2017	Beamsville TS	30	280
2018	Beamsville TS	30	280
2019	Beamsville TS	30	280
	Beamsville TS Total	**277**	**2,577**
2010	Vineland DS	6	54
2011	Vineland DS	25	242
2012	Vineland DS	15	139
2013	Vineland DS	30	260
2014	Vineland DS	23	214
2015	Vineland DS	23	214
2016	Vineland DS	23	214
2017	Vineland DS	23	214
2018	Vineland DS	23	214
2019	Vineland DS	23	214
	Vineland DS Total	**214**	**1,979**
2010	Niagara West TS	15	137
2011	Niagara West TS	18	170
2012	Niagara West TS	2	20
2013	Niagara West TS	0	0
2014	Niagara West TS	20	190
2015	Niagara West TS	20	190
2016	Niagara West TS	20	190
2017	Niagara West TS	20	190
2018	Niagara West TS	20	190
2019	Niagara West TS	20	190
	Niagara West TS Total	**155**	**1,467**
	Total Installed	**646**	**6,023**

The number of connections and installed capacity forecasted for the period 2014 to 2019 is based on the average of connections experienced during the period 2011 to 2013. It should be noted that at Niagara West TS, connections have not been permitted since 2012 due to a restriction in available short circuit capacity. Niagara West TS is currently being upgraded by the Niagara West Transformer Corporation to remove this constraint and connections are expected to resume in late 2014.

In the Niagara Falls area, NPEI connected 79 microFIT installations during the period 2010 to 2013. The following table summarizes the historical and forecast microFIT connections in the Niagara Falls area:

Table 5 - 21: microFIT Connection Forecast - Niagara Falls

Year	Transformer Station	# of Connections	Capacity (kW)
2010	Kalar TS	0	-
2011	Kalar TS	5	25
2012	Kalar TS	5	38
2013	Kalar TS	17	150
2014	Kalar TS	9	71
2015	Kalar TS	9	71
2016	Kalar TS	9	71
2017	Kalar TS	9	71
2018	Kalar TS	9	71
2019	Kalar TS	9	71
	Kalar TS Total	**81**	**639**
2010	Murray TS	2	20
2011	Murray TS	10	91
2012	Murray TS	7	67
2013	Murray TS	15	126
2014	Murray TS	11	95
2015	Murray TS	11	95
2016	Murray TS	11	95
2017	Murray TS	11	95
2018	Murray TS	11	95
2019	Murray TS	11	95
	Murray TS Total	**100**	**874**
2010	Stanley TS	0	-
2011	Stanley TS	5	35
2012	Stanley TS	7	62
2013	Stanley TS	6	51
2014	Stanley TS	6	49
2015	Stanley TS	6	49
2016	Stanley TS	6	49
2017	Stanley TS	6	49
2018	Stanley TS	6	49
2019	Stanley TS	6	49
	Stanley TS Total	**54**	**442**
	Grand Total	**235**	**1,955**

The number of connections and installed capacity forecasted for the period 2014 to 2019 is based on the average of connections experienced during the period 2011 to 2013.

In the Fonthill area, NPEI connected 7 microFIT installations during the period 2010 to 2013. The following table summarizes the historical and forecast microFIT connections in the Fonthill area:

Table 5 - 22: microFIT Connection Forecast - Fonthill

Year	Transformer Station	# of Connections	Capacity (kW)
2010	Allanburg TS	1	10
2011	Allanburg TS	5	50
2012	Allanburg TS	1	10
2013	Allanburg TS	0	-
2014	Allanburg TS	2	20
2015	Allanburg TS	2	20
2016	Allanburg TS	2	20
2017	Allanburg TS	2	20
2018	Allanburg TS	2	20
2019	Allanburg TS	2	20
	Allanburg TS Total	**19**	**190**
	Grand Total	**19**	**190**

5.4.3.3 Capacity to Connect REG

Based on historical FIT and microFIT connections, NPEI has assessed the forecast connected capacity at each supply point. The following table summarizes the forecast of REG connections by transformer station:

Table 5 - 23: Forecast REG Connection by Supply Point

Delivery Point	Service Area	Thermal Rating (MVA)	Forecasted REG Connection (MVA)
Allanburg TS	Fonthill	9.6	0.2
Beamsville TS	Lincoln/West Lincoln	25/41.6	2.9
Kalar TS	Niagara Falls	22.5/30/37.5	0.6
Murray TS	Niagara Falls	67.5/90/112.5	0.9
Niagara West TS	Lincoln/West Lincoln	40/53.2/63.4	12.5
Stanley TS	Niagara Falls	40/53.3/66.7	0.8
Vineland DS	Lincoln/West Lincoln	15/20/25	3.4

In review of projected FIT and microFIT connections over the forecast period (2015 - 2019), NPEI does not expect any issues related to feeder constraints or transformer station thermal capacity on REG connections. As previously outlined, there are currently short circuit limitations at each of NPEI's delivery points that have limited connection of FIT based REG projects. These limitations are expected to be removed in 2015. The projections for the period 2016 to 2019 are based on historical averages of microFIT and FIT connections and ratings with large FIT projects removed.

Based on this assessment, NPEI has not included any REG investments in the forecast period.

5.4.4 Capital Expenditure Summary

The capital project expenditures over the five year historical years (2010 - 2014) and the five forecast years (2015 - 2019) are categorized as System Access, System Renewal, System Service, or General Plant based on primary investment drivers. The following table summarizes the Capital Expenditures from 2010 to 2019:

Table 5 - 24: Capital Expenditure Summary - Historical

CATEGORY	Historical Period (previous plan[1] & actual)														
	2010			2011			2012			2013			2014 Bridge Year		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	2,130	2,558	20.1%	2,199	942	-57.2%	1,630	1,086	-33.4%	2,031	1,997	-1.6%	1,731	1,731	0.0%
System Renewal	2,998	2,769	-7.6%	4,768	4,162	-12.7%	7,870	5,150	-34.6%	5,838	5,907	1.2%	7,307	7,307	0.0%
System Service	6,699	6,465	-3.5%	1,512	1,966	30.0%	2,362	1,424	-39.7%	1,100	847	-23.0%	580	2,483	328.1%
General Plant	1,820	1,621	-10.9%	1,123	1,280	14.0%	2,769	2,621	-5.4%	6,028	3,897	-35.3%	3,267	3,267	0.0%
TOTAL	13,647	13,413	-1.7%	9,603	8,350	-13.0%	14,631	10,280	-29.7%	14,997	12,649	-15.7%	12,885	14,788	14.8%
System O&M	$ 5,731	$ 5,691	-0.7%	$ 6,142	$ 6,282	2.3%	$ 6,764	$ 6,708	-0.8%	$ 6,880	$ 6,281	-8.7%	$ 6,636	$ 6,636	0.0%

Table 5 - 25: Capital Expenditure Summary - Forecast

CATEGORY	Forecast Period (planned)				
	2015 Test Year	2016	2017	2018	2019
	$ '000				
System Access	2,429	2,249	1,821	1,933	1,663
System Renewal	6,383	4,161	5,889	7,301	7,223
System Service	926	3,760	2,449	769	1,330
General Plant	1,447	1,434	1,352	1,204	1,311
TOTAL	11,185	11,605	11,511	11,207	11,528
System O&M	$ 6,846	$ 6,983	$ 7,123	$ 7,265	$ 7,410

5.4.4.1 Comparison of Plan vs. Actual by Category 2010 - 2014

The markedly different variances of plan versus acutal from 2010 to 2014 are described below:

2010

System Access: Planned = $2,130K, Actual = $2,558K, Variance = $428K, 20.1%

This variance is mainly due to municipal line relocations and subdivision projects being greater than budgeted. Projects contributing to this variance include:

- South Pelham Street - $167K
- Subdivisions - $83K
- Oakwood Drive relocation - $160K

2011

System Access: Planned = $2,199K, Actual = $942K, Variance = ($1,257K), -57.2%

This variance is mainly due to subdivision projects being lower than budgeted and capital contributions being greater than budgeted. Projects contributing to this variance include:

- Subdivisions – ($360K)
- Capital Contributions – ($722K)

System Service: Planned = $1,512K, Actual = $1,966K, Variance = $454K, 30.0%

This variance is mainly due to a 2010 system service project that was largely deferred until 2011 (Robinson St. Primary Extension), partially offset by lower than budgeted switchgear replacement and double circuit extension on Montrose Road. Projects contributing to this variance include:

- Robinson St. Primary Extension– $733K
- KM2 and KM6 Montrose – Mcleod – ($253)
- Switchgear Replacement – ($209K)

2012

System Access: Planned = $1,630K, Actual = $1,086K, Variance = ($544K), -33.4%

This variance is mainly due capital contributions being greater than budgeted. Projects contributing to this variance include:

- Capital Contributions – ($627K)

System Renewal: Planned = $7,870K, Actual = $5,150K, Variance = ($2,720K), -34.6%

In 2012, based on discussions with Hydro One Networks, NPEI budgeted to purchase an asset from Hydro One at a cost of $2.4 million. This purchase did not occur. Projects contributing to this variance include:

- Budgeted System Renewal asset not purchased – ($2,360K)

System Service: Planned = $2,362K, Actual = $1,424K, Variance = ($938K), -39.7%

This variance is mainly due to the fact that smart meter capital costs were included in the budgeted amount, under system service. The actual smart meter capital costs were recorded in the smart meter variance account. This variance reverses in 2014 as smart meter capital costs are moved to rate base. Projects contributing to this variance include:

- Smart Meter costs included in system service planned amount – ($1,114K).

2013

System Service: Planned = $1,100K, Actual = $847K, Variance = ($253K), -23.0%

This variance is mainly due lower than budgeted switchgear and sectionalizing costs. Projects contributing to this variance include:

- Switchgear Replacement – ($136K).
- Sectionalizing switch replacement – ($140K)

General Plant: Planned = $6,028K, Actual = $3,897K, Variance = ($2,131K), -35.3%

This variance is mainly due to renovations of NPEI's stores and operations area, which were originally budgeted for 2013 being deferred until 2014. Hardware and Software purchases in 2013 were also less than budgeted.

- Deferred building projects – ($1,523K).
- Hardware – ($318K)
- Software – ($168K).

2014

System Service: Planned = $580K, Actual = $2,483K, Variance = $1,903K, 328.1%

This variance is due to capital costs moved from the smart meter variance accounts to rate base in 2014, as a result of the Board's Decision and Order in NPEI's Smart Meter Application (EB-2013-0359). This represents the balance of smart meter capital costs from July 1, 2010 to December 31, 2013.

- Smart Meter Capital moved to rate base - $1,903K

5.4.4.2 Comparison of Actual Year over Year by Category 2010 - 2015

The markedly different variances of year over year actual from 2010 to 2015 are described below:

2011 versus 2010

Total Capital Expenditures: 2010 = $13,413K, 2011 = $8,350K

Variance = ($5,033K), -37.7%

This variance is mainly due to smart meter capital costs of $4,175K that were transferred from NPEI's smart meter variance accounts to rate base in 2010. Also, NPEI collected $411K more in capital contributions in 2011 than in 2010.

2012 versus 2011

Total Capital Expenditures: 2011 = $8,350K, 2012 = $10,281K

Variance = $1,931K, 23.1%

Vehicle additions were $1,161K in 2012 (including 4 large vehicles) versus $542K in 2011 (including 2 large vehicles), which is an increase of $619K. Also, workspace optimization of existing office space took place in 2012, with a cost of $303K.

2013 versus 2012

Total Capital Expenditures: 2012 = $10,281K, 2013 = $12,648K

Variance = $2,367K, 23.0%

This variance is mainly due to building and yard projects completed at NPEI's Niagara Falls property: new wire building $907K, yard excavation $533K and high mast lighting $435K.

2014 versus 2013

Total Capital Expenditures: 2013 = $12,648K, 2014 Projected = $14,788K

Variance = $2,140K, 16.9%

This variance is mainly due to capital costs of $1,903K which were moved from NPEI's smart meter variance accounts to rate base in 2014.

2015 versus 2014

Total Capital Expenditures: 2014 Projected = $14,788K, 2015 Budget = $11,185K

Variance = ($3,603K), -24.4%

This variance is partly due to capital costs of $1,903K which were moved from NPEI's smart meter variance accounts to rate base in 2014. Also, all workspace optimization, yard and wire building projects from 2013 to 2014 were completed by the end of 2014.

5.4.5 Justifying Capital Expenditures

5.4.5.1 Overall Plan

Table 5 - 26 illustrates the proportion of Capital Expenditures in each investment category for the historical period 2010 to 2014.

Table 5 - 26: Historical Expenditures by Category

CATEGORY	Historical Period (actual)					
	2010	2011	2012	2013	2014	% of Plan
	$ '000					
System Access	2,558	942	1,630	1,997	1,731	14%
System Renewal	2,769	4,162	7,870	5,907	7,307	44%
System Service	6,465	1,966	2,362	847	2,483	22%
General Plant	1,621	1,280	2,769	3,897	3,267	20%
TOTAL	13,413	8,350	14,631	12,649	14,788	

System Access Investments

System Access based investments account for approximately 14% of historical capital expenditures. These investments relate to external drivers such as municipal road works, private development and demand for new connections to the electrical distribution system.

System Renewal Investments

System Renewal based investments account for approximately 44% of historical capital expenditures. The majority of investments in this category are based on the results of the asset condition assessment report. Major programs related to system renewal expenditures are the pole replacement program and kiosk replacement program.

System Service Investments

Approximately 22% of NPEI's historical capital expenditures are in the system service category. These investments were aimed at improving reliability and system efficiency through distribution system expansion and grid modernization expenditures.

General Plant

General plan investments represent approximately 20% of NPEI's historical capital expenditures. The expenditures are related to assets that are not part of the distribution system including buildings, IT infrastructure, vehicles, tools, and equipment.

Table 5 - 27 illustrates the proportion of Capital Expenditures in each investment category for the forecast period 2015 to 2019.

Table 5 - 27: Forecast Expenditures by Category

CATEGORY	Forecast Period (planned)					
	2015	2016	2017	2018	2019	% of Plan
	$ '000					
System Access	2,429	2,249	1,821	1,933	1,663	18%
System Renewal	6,383	4,161	5,889	7,301	7,223	54%
System Service	926	3,760	2,449	769	1,330	16%
General Plant	1,447	1,434	1,352	1,204	1,311	12%
TOTAL	11,185	11,605	11,511	11,207	11,528	

In comparison of Table 5 - 26 to Table 5 - 27, there is a relatively consistent composition of capital expenditures across the investment categories. This is expected based on consistent connection and expansion demands, asset management strategies, and investment alignment was strategic business values.

5.4.5.2 Material Investments

This section provides information regarding material projects for the capital expenditure planning period 2010 to 2019. Project narratives have been prepared to address the requirements of Section 5.4.5.2 of Chapter 5.

Project narratives for the historical period 2010 to 2014 are included in Appendix M of this document. The projects are summarized in Table 5 - 28.

Project narratives for the forecast period 2015 to 2019 are included in Appendix N of this document. The projects are summarized in Table 5 - 29.

Table 5 - 28: Summary of Historical Material Projects

Project #	Reference #	Project Title	Category	Page #
2010-0009	SA-41	Kalar Rd. Catalina to Beaverdams	System Access	2
2010-0016	SA-39	Side Streets of Dorchester Rd. from the N.S.&T. ROW to Morrison	System Access	4
2010-0026	SA-49	South Pelham St. - Fonthill Downtown Betterment	System Access	6
2010-0053		Oakwood Drive - Smart Center Line Relocate	System Access	8
2010-1008,1009,Various	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	10
2010-Various	SA-43	Line Relocation due to Municipal Works (Less Than Materiality)	System Access	11
2010-Various		Subdivision - Distribution System Expansion	System Access	12
2011-0009	SA-48	Carry Over - Kalar Rd. Catalina to Beaverdams	System Access	13

2011-1008,1009,Various	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	14
2011-Various	SA-43	Line Relocation due to Municipal Works (Less Than Materiality)	System Access	15
2011-Various		Subdivision - Distribution System Expansion	System Access	16
2011-0072	SA-40	Drummond and Lundy's Lane Conflicts	System Access	17
2012-1008,1009,Various	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	19
2012-Various	SA-43	Line Relocation due to Municipal Works (Less Than Materiality)	System Access	20
2012-Various		Subdivision - Distribution System Expansion	System Access	21
2013-0100	SA-38	Kalar Rd. Widening - Catalina to Rideau	System Access	22
2013-1008,1009,Various	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	24
2013-Various	SA-43	Line Relocation due to Municipal Works (Less Than Materiality)	System Access	25
2013-Various		Subdivision - Distribution System Expansion	System Access	26
2014-1008	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	27
2014-Various	SA-43	Line Relocation due to Municipal Works (Less Than Materiality)	System Access	28
2014-Various		Subdivision - Distribution System Expansion	System Access	29
2010-0017	SR-10	Campden DS Feeder Egress	System Renewal	30
2010-0025	SR-4	Pelham MS Rebuild	System Renewal	32
2010-1007 & 2007	SR-30	System Sustainment / Minor Betterments	System Renewal	33
2010-1010 & 2010	SR-31	Pole Replacement Program	System Renewal	34
2010-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	36
2011-0004	SR-13	Lundy's Lane Line Build - Montrose to Kalar	System Renewal	37
2011-0005	SR-15	Riall Street Rebuild	System Renewal	39
2011-0007	SR-14	Murray Street Area Rebuild - Bounded by Culp/Dunn/Main/Drummond	System Renewal	41
2011-0011	SR-11	System Sectionalizing Devices	System Renewal	43
2011-0013	SR-5	Smithville DS Rebuild	System Renewal	44
2011-0017	SR-12	Campden DS Rebuild	System Renewal	45
2011-0022	SR-6	Station St. DS Rebuild	System Renewal	46

2011-1007 & 2007	SR-30	System Sustainment / Minor Betterments	System Renewal	47
2011-1010 & 2010	SR-31	Pole Replacement Program	System Renewal	48
2011-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	50
2011-0005	SR-15	Carry Over - Riall Street Rebuild	System Renewal	51
2011-0013	SR-5	Carry Over - Smithville DS Rebuild	System Renewal	52
2011-0022	SR-6	Carry Over - Station St. DS Rebuild	System Renewal	53
2011-0001	SR-17	Montrose Rd. Rebuild Lundy's Lane to Kinsmen Court	System Renewal	54
2012-0002	SR-16	Lundy's Lane / Ker St. UG Distribution Replacement	System Renewal	56
2012-0007	SR-18	Carry Over - Murray Street Area Rebuild - Bounded by Culp/Dunn/Main/Drummond	System Renewal	58
2012-0012	SR-6	Greenlane DS Rebuild	System Renewal	60
2012-0014	SR-19	Victoria Ave. Voltage Conversion	System Renewal	61
2012-1007 & 2007	SR-30	System Sustainment / Minor Betterments	System Renewal	63
2012-1010 & 2010	SR-31	Pole Replacement Program	System Renewal	64
2012-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	66
2011-0022	SR-6	Carry Over - Station St. DS Rebuild	System Renewal	67
2012-0012	SR-6	Carry Over - Greenlane DS Rebuild	System Renewal	68
2012-0014	SR-19	Carry Over - Victoria Ave. Voltage Conversion	System Renewal	69
2013-0003	SR-22	Weightman Bridge Underground Primary Extension	System Renewal	70
2013-0005	SR-1	12M6 Conductor Replacement Simcoe, Buckly, Armoury St. Area	System Renewal	72
2013-0007	SR-20	Carry Over - Murray Street Area Rebuild - Bounded by Culp/Dunn/Main/Drummond	System Renewal	74
2013-0008	SR-3	High Street Rebuild - Dorchester Road to Station #10	System Renewal	76
2013-0011	SR-2	Dorchester Rebuild - Garden to McMillan	System Renewal	78
2013-0017	SR-9	Station 8 MS Rebuild	System Renewal	80

2013-0021	SR-21	Beacon Inn/Jordan - Overhead to Underground Primary Conversion	System Renewal	81
2013-1007 & 2007	SR-30	System Sustainment / Minor Betterments	System Renewal	83
2013-1010 & 2010	SR-31	Pole Replacement Program	System Renewal	84
2013-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	86
2013-2011	SR-33	PCB Transformer Replacement Program	System Renewal	87
2013-0003	SR-22	Carry Over - Weightman Bridge Underground Primary Extension	System Renewal	89
2013-0005	SR-1	Carry Over - 12M6 Conductor Replacement Simcoe, Buckly, Armoury St. Area	System Renewal	90
2013-0011	SR-2	Carry Over - Dorchester Rebuild - Garden to McMillan	System Renewal	91
2013-0017	SR-9	Carry Over - Station 8 MS Rebuild	System Renewal	92
2014-0001	SR-24	Crawford Street Rebuild - Thorold Stone to Sheldon	System Renewal	93
2014-0004	SR-25	Fallsview Blvd. Rebuild - Ferry to Robinson	System Renewal	95
2014-0007	SR-29	Station 22 South Rebuild - Bounded by Dorchester / Coach / Clare / Pew	System Renewal	97
2014-0008	SR-28	Rolling Acres OH to UG Conversion - Phase 1	System Renewal	99
2014-0009	SR-23	3M28, 29, 30 Feeder Egress Replacement	System Renewal	101
2014-0015	SR-26	Jordan Road Rebuild from Red Maple to the QEW	System Renewal	103
2014-1006	SR-27	Murray Y Bus Wholesale Meter Replacement	System Renewal	105
2014-1007 & 2007	SR-30	System Sustainment / Minor Betterments	System Renewal	106
2014-1010 & 2010	SR-31	Pole Replacement Program	System Renewal	107
2014-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	109
2014-2011	SR-33	PCB Transformer Replacement Program	System Renewal	110
2010-0001	SS-37	Robinson St. Allendale to Clark UG Primary Extension	System Service	112
2010-0002	SS-37	High Street Area Rebuild	System Service	114
2010-0006	SS-34	Switchgear Replacement Program	System Service	116

2010-0007	SS-37	Murray Street Area Rebuild - Culp St. from Main to Drummond	System Service	118
2010-0008	SS-47	Oakwood Drive - Line Relocate	System Service	120
2010-0023	SS-36	Durham Voltage Conversion	System Service	122
2010-0024	SS-35	Cherry Avenue Voltage Conversion	System Service	124
2010-Smart Meters		Smart Meters	System Service	126
2010-0001	SS-37	Carry Over - Robinson St. Allendale to Clark UG Primary Extension	System Service	127
2011-0003	SS-50	KM2 - KM6 Extension Montrose Rd., McLeod to Canadian Drive	System Service	128
2011-0006	SS-34	Switchgear Replacement Program	System Service	130
2011-0008	SS-48	Kalar Rebuild - N.S. & T. ROW to Beverdams	System Service	132
Mobile Substation		Mobile Substation	System Service	134
2012-0003	SS-51	Kalar MTS - KM1 and KM5 Feeder Egress	System Service	136
2012-0006	SS-34	Switchgear Replacement Program	System Service	138
2012-0008	SS-48	Carry Over Kalar Rebuild - N.S. & T. ROW to Beverdams	System Service	140
2012-SG		Grid Modernization Program	System Service	141
2013-0006	SS-34	Switchgear Replacement Program	System Service	143
2013-SG		Grid Modernization Program	System Service	145
2014-0006	SS-34	Switchgear Replacement Program	System Service	147
2014-0018	SS-53	King Street - 27.6kV Extension to Martin Road	System Service	149
2014-SG		Grid Modernization Program	System Service	151
2014-Smart Meters		Smart Meters	System Service	153
2010-General Plant		General Plant	General Plant	154
2011-General Plant		General Plant	General Plant	156
2012-General Plant		General Plant	General Plant	158
2013-General Plant		General Plant	General Plant	160
2014-General Plant		General Plant	General Plant	163

Table 5 - 29: Summary of Forecast Material Projects

Project #	Reference #	Project Title	Category	Page #
2015-0001	SA-55	Niagara Parks Commission Primary Network	System Access	2
2015-1008	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	4
2015-1009		Subdivision - Distribution System Expansion	System Access	5
2015-Various	SA-43	Line Relocation due to Municipal Works	System Access	6
2016-0001	SA-63	Clifton Hill Primary Upgrade	System Access	7
2016-0002	SA-64	N.S.&T. R.O.W. Crossing at the QEW	System Access	9
2016-1008	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	11
2016-1009		Subdivision - Distribution System Expansion	System Access	12
2016-Various	SA-43	Line Relocation due to Municipal Works	System Access	13
2017-1008	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	14
2017-1009		Subdivision - Distribution System Expansion	System Access	15
2017-Various	SA-43	Line Relocation due to Municipal Works	System Access	16
2018-0001	SA-82	Concession 2 Rd. Between Caistorville Rd. and Westbrook Rd	System Access	17
2018-1008	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	19
2018-1009		Subdivision - Distribution System Expansion	System Access	20
2018-Various	SA-43	Line Relocation due to Municipal Works	System Access	21
2019-1008	SA-42	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	System Access	22
2019-1009		Subdivision - Distribution System Expansion	System Access	23
2019-Various	SA-43	Line Relocation due to Municipal Works	System Access	24
2015-0001	SR-24	Crawford Street Rebuild - Thorold Stone to Sheldon - Carry Over	System Renewal	25
2015-0003	SR-60	Willodell Road - Gonder to Koabel Road	System Renewal	26
2015-0004	SR-58	Willoughby Drive - Main Street to Cattell Drive	System	28

			Renewal	
2015-0005	SR-59	Willoughby Drive - Cattell Drive to Weinbrenner Road	System Renewal	30
2015-0007	SR-7	Station 22 South Rebuild - Phase 1 Carry Over / Phase 2	System Renewal	32
2015-0008	SR-28	Rolling Acres OH to UG Conversion - Phase 2	System Renewal	34
2015-0009	SR-57	NWTS Metering Replacement	System Renewal	36
2015-0011	SR-56	Frederica Street - Dorchester to Drummond Rebuild	System Renewal	37
2015-0015	SR-26	Jordan Road Rebuild Phase II - Honsberger from Jordan Road to Thirteenth Street	System Renewal	39
2015-1007	SR-30	System Sustainment / Minor Betterments	System Renewal	41
2015-1010	SR-31	Pole Replacement Program	System Renewal	42
2015-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	45
2015-2011	SR-33	PCB Transformer Replacement Program	System Renewal	46
2016-0003	SR-65	Jordan Road Voltage Conversion Phase 3	System Renewal	48
2016-0004	SR-66	Dorchester Road Rebuild McLeod Road to Dunn Street	System Renewal	50
2016-0008	SR-28	Rolling Acres OH to UG Conversion - Phase 3	System Renewal	52
2016-1007	SR-30	System Sustainment / Minor Betterments	System Renewal	54
2016-1010	SR-31	Pole Replacement Program	System Renewal	55
2016-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	58
2017-0001	SR-73	Thorold Stone Road Rebuild - Montrose to Kalar	System Renewal	59
2017-0002	SR-74	Portage Rd. Rebuild - Mountain Road to Church's Lane	System Renewal	61
2017-0003	SR-75	Subdivision Rehabilitation Phase 1	System Renewal	63
2017-0004	SR-76	Station St. DS Power TX Replacement	System Renewal	65
2017-0007	SR-72	Station 14 Voltage Conversion Phase 1	System Renewal	66
2017-0008	SR-77	Campden DS Power TX Relocate	System Renewal	68
2017-0009	SR-78	Kalar TS Protection Refurbishment	System Renewal	70

2017-1007	SR-30	System Sustainment / Minor Betterments	System Renewal	71
2017-1010	SR-31	Pole Replacement Program	System Renewal	72
2017-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	75
2018-0002	SR-83	Pole-mount Step-down Transformer Eliminations	System Renewal	76
2018-0003	SR-75	Subdivision Rehabilitation Phase 2	System Renewal	78
2018-0004	SR-84	Mountain Rd Rebuild - Dorchester to St. Paul	System Renewal	79
2018-0005	SR-85	Mountain Rd Rebuild - Dorchester to Mewburn	System Renewal	81
2018-0007	SR-72	Station 14 Voltage Conversion Phase 2	System Renewal	83
2018-0008	SR-86	Sinnicks Ave Rebuild - Thorold Stone to Swayze Drive	System Renewal	84
2018-0009	SR-87	Cherryhill Dr./Cherrygrove Rd. Rebuild	System Renewal	86
2018-1007	SR-30	System Sustainment / Minor Betterments	System Renewal	88
2018-1010	SR-31	Pole Replacement Program	System Renewal	89
2018-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	92
2019-0001	SR-87	King St. Bartlett to Cherry Ave. Rebuild Phase 1	System Renewal	93
2019-0002	SR-83	Pole-mount Step-down Transformer Eliminations	System Renewal	95
2019-0003	SR-75	Subdivision Rehabilitation Phase 3	System Renewal	97
2019-0004	SR-88	Ontario Ave. Side Street Rebuild and Conversion	System Renewal	99
2019-0005	SR-89	McRae Street Area Rebuild	System Renewal	101
2019-0007	SR-72	Station 14 Voltage Conversion Phase 3 (Final Phase)	System Renewal	103
2019-1007	SR-30	System Sustainment / Minor Betterments	System Renewal	104
2019-1010	SR-31	Pole Replacement Program	System Renewal	105
2019-0020	SR-32	Kiosk/Submersible Replacement Program	System Renewal	108
2015-0006	SS-34	Switchgear Replacement Program	System Service	109
2015-0018	SS-53	King Street - 27.6kV Extension to Martin Road -	System	111

		Carry Over	Service	
2015-SG	SS-61	Grid Modernization Program	System Service	112
2016-0005	SS-67	Victoria Ave. South of Fly Rd. Phase 1	System Service	114
2016-0006	SS-34	Switchgear Replacement Program	System Service	116
2016-0007	SS-68	Oakwood Drive South of Smart Centers to the QEW Crossing	System Service	118
2016-0009	SS-69	Glenholm to Franklin Ave. - 600kcMIL Underground Install	System Service	120
2016-0010	SS-70	Downtown Core PILCDSTA De-Commissioning	System Service	122
2016-0011	SS-71	Dorchester Road Rebuild - Mountain Road to Riall Street	System Service	124
2016-SG	SS-61	Grid Modernization Program	System Service	126
2017-0005	SS-67	Victoria Ave. South of Fly Rd. Phase 2	System Service	128
2017-0006	SS-34	Switchgear Replacement Program	System Service	130
2017-0010	SS-79	Greenlane Road at Ontario Street Tie Point	System Service	132
2017-0011	SS-80	Chippawa - Redundant Supply Upgrades Phase 1	System Service	134
2017-0012	SS-81	Brown Road Extension - Montrose to Blackburn Parkway	System Service	136
2017-SG	SS-61	Grid Modernization Program	System Service	138
2018-0006	SS-34	Switchgear Replacement Program	System Service	140
2018-SG	SS-61	Grid Modernization Program	System Service	142
2019-0006	SS-34	Switchgear Replacement Program	System Service	144
2019-0011	SS-80	Chippawa - Redundant Supply Upgrades Phase 2	System Service	146
2018-SG	SS-61	Grid Modernization Program	System Service	148
2015-2019-General Plant		General Plant	System Service	150

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APPENDIX A

Integrated Regional Resource Planning (IRRP)

From: Miriam Heinz [mailto:Miriam.Heinz@powerauthority.on.ca]
Sent: Thursday, August 14, 2014 9:25 AM
To: Tom Sielicki
Subject: RE: Request for IRRP Status and Distribution System Plan

Ok that's fair Tom will have something prepared and send over a draft for your review.

Thanks for the clarification.

Miriam

From: Tom Sielicki [tom.sielicki@npei.ca]
Sent: August-14-14 7:56 AM
To: Miriam Heinz
Subject: RE: Request for IRRP Status and Distribution System Plan

Hi Miriam--NPEI was going to include the letter as an Appendix within our Customer Engagement Plan, so if it is possible, we would like it ahead of the REG Plan submission.
Thanks

Tom Sielicki, C.E.T.
Vice President of Engineering
Niagara Peninsula Energy Inc.
905-353-6016
tom.sielicki@npei.ca<mailto:tom.sielicki@npei.ca>

From: Miriam Heinz [mailto:Miriam.Heinz@powerauthority.on.ca]
Sent: Wednesday, August 13, 2014 5:25 PM
To: Tom Sielicki
Subject: RE: Request for IRRP Status and Distribution System Plan

Hi Tom. Upon checking, I see that Niagara Peninsula Energy Inc. is part of Group 3 and the Niagara Region for regional planning purposes. At the present time neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has commenced for Niagara Peninsula’s service territory, and planning may not commence until 2015 when the transmitter will kick off the needs screening process.

However in our comment letter to you on your REG investments as part of your distribution system plan, the above facts will also be stated. Please see other letters that reference this fact which are posted to the OPA's website: http://www.powerauthority.on.ca/about-us/regulatory-affairs/distribution-system-plans-comment-letters-process-submission

So, my question to you is whether you need this information ahead of time, or whether it can be contained within the OPA's comment letter after we receive your REG investments information as part of your DSP.

Please let me know.

Thanks Tom.

Miriam Heinz
Regulatory Coordinator | Legal, Aboriginal and Regulatory Affairs Ontario Power Authority | 120 Adelaide Street West, Suite 1600 | Toronto, ON M5H 1T1 T (416) 969-6045 | E
Miriam.heinz@powerauthority.on.ca<mailto:Miriam.heinz@powerauthority.on.ca> |
www.powerauthority.on.ca<http://www.powerauthority.on.ca/>

From: Miriam Heinz
Sent: Tuesday, August 12, 2014 12:58 PM
To: Tom Sielicki
Subject: RE: Request for IRRP Status and Distribution System Plan

Hi Tom. The OPA would be glad to provide you information on the planning status. By when would you need such a letter?

I'm also expecting then to receive information from Kinectrics on your renewable energy generation investments as it relates to your DSP, so that the OPA may provide you with a comment letter. Please see the information below taken from our website: http://www.powerauthority.on.ca/about-us/regulatory-affairs/distribution-system-plans-comment-letters-process-submission

Process for an LDC to submit a DS Plan to the Ontario Power Authority Filing Requirements Section 5.1.4.2 Renewable energy generation investments states:

Prior to filing a DS Plan, a distributor must:

1. Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and request in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor's filing timetable.

Please use this email address - Regulatory.Affairs@powerauthority.on.ca<mailto:Regulatory.Affairs@powerauthority.on.ca> - when submitting a DS Plan or information relating to your renewable energy generation investments to the OPA. Please include any specific instructions, including the name of the person to be contacted if OPA staff has questions about the content of your information during the review period and the date that you require a response.

Once your DS Plan has been submitted to the OPA, it will be reviewed by the appropriate electricity system planners and FIT program administrators.

The OPA comments, to be included with your Ontario Energy Board applications, will be returned to you through email on or before the timelines specified by the LDC that conforms to the distributor's filing timetable.

Section 5.1.4.2 states that [t]he Board expects that the OPA comment letter will include:

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

OPA Contact Information

The OPA encourages LDCs to get in touch with the OPA for further assistance with respect to the preparation of Distribution System Plans or about the information required and the review process in general. For further assistance please contact:

Regulatory Affairs
Ms. Miriam Heinz, Regulatory Coordinator
416 969-6045
miriam.heinz@powerauthority.on.ca<mailto:miriam.heinz@powerauthority.on.ca>

Miriam Heinz
Regulatory Coordinator | Legal, Aboriginal and Regulatory Affairs Ontario Power Authority | 120 Adelaide Street West, Suite 1600 | Toronto, ON M5H 1T1 T (416) 969-6045 | E
Miriam.heinz@powerauthority.on.ca<mailto:Miriam.heinz@powerauthority.on.ca> |
www.powerauthority.on.ca<http://www.powerauthority.on.ca/>

From: Tom Sielicki [mailto:tom.sielicki@npei.ca]
Sent: Tuesday, August 12, 2014 9:26 AM
To: Miriam Heinz
Subject: Request for IRRP Status and Distribution System Plan

Hi Miriam--Please find attached a request from Niagara Peninsula Energy for a Regional Planning Status Letter for our 2014 Cost of Service Rate Application. A hard copy will follow by Post. Your contact information was provided by Kinectrics, who is processing our DSP, please let me know if there is someone else within your Organization who should have received this request, if this information is incorrect. Thank you for your co-operation on this matter, and your earliest reply would be greatly appreciated.

Tom Sielicki, C.E.T.
Vice President of Engineering
Niagara Peninsula Energy Inc.
905-353-6016
tom.sielicki@npei.ca<mailto:tom.sielicki@npei.ca>

APPENDIX B

Regional Infrastructure Planning (RIP)

Hydro One Network Inc.
483 Bay Street
6th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

August 19, 2014

Tom Sielicki
V.P. of Engineering
Niagara Peninsula Energy Inc.
7447 Pin Oak Drive, P.O. Box 120
Niagara Falls, Ontario, L2E 6S9

Dear Mr. Sielicki**:**

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) belongs to the Niagara Region, which is in Group 3. A map showing details with respect to the 21 Regions/Groups and list of LDCs in each Region is attached in Appendix A and B respectively.

This letter is to confirm that the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the Niagara Region affecting the Niagara Peninsula Energy Region. I am expecting, as per the new process, that the regional planning for the Niagara Region may be initiated in 3rd or 4th quarter of 2015. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

The new planning process provides flexibility during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One looks forward to working with Niagara Peninsula Energy Inc. in executing the new regional planning process.

If you have any further questions, please feel free to contact me.

Sincerely,
Ajay Garg, |Manager – Regional Planning Coordination|
Hydro One Networks Inc.

Cc:
Brad Colden, Manager – Key Accounts Manager

niagara
peninsula
energy

August 12, 2014

Hydro One Network Inc.
483 Bay Street
15th Floor, South Tower
Toronto, ON M5G 2P5

Attention: Mr. Ajay Garg
Manager-Regional Planning Coordination and Load Connections

Subject: Regional Planning Status

Please be advised that Niagara Peninsula Energy Inc. is in the Process of preparing its 2014 Cost of Service Rate Application for filing in October of 2014, and as part of the Application will be filing a distribution System Plan.

On March 28, 2013 the Ontario Energy Board issued proposed Distribution System Code amendment entitled " Chapter 5, Consolidated Distribution Plan Filing Requirements", which includes under subsection 5.1.4.1 Regional Planning and Consultations, the Distributor's obligation to participate in the regional planning process, including integrated regional resource planning (IRRP) lead by the OPA.

Niagara Peninsula Energy is interested in participating in your planning process and asks if you could please provide an update on this process in regards to the Niagara Region via a Regional Planning Status Letter at your earliest convenience.

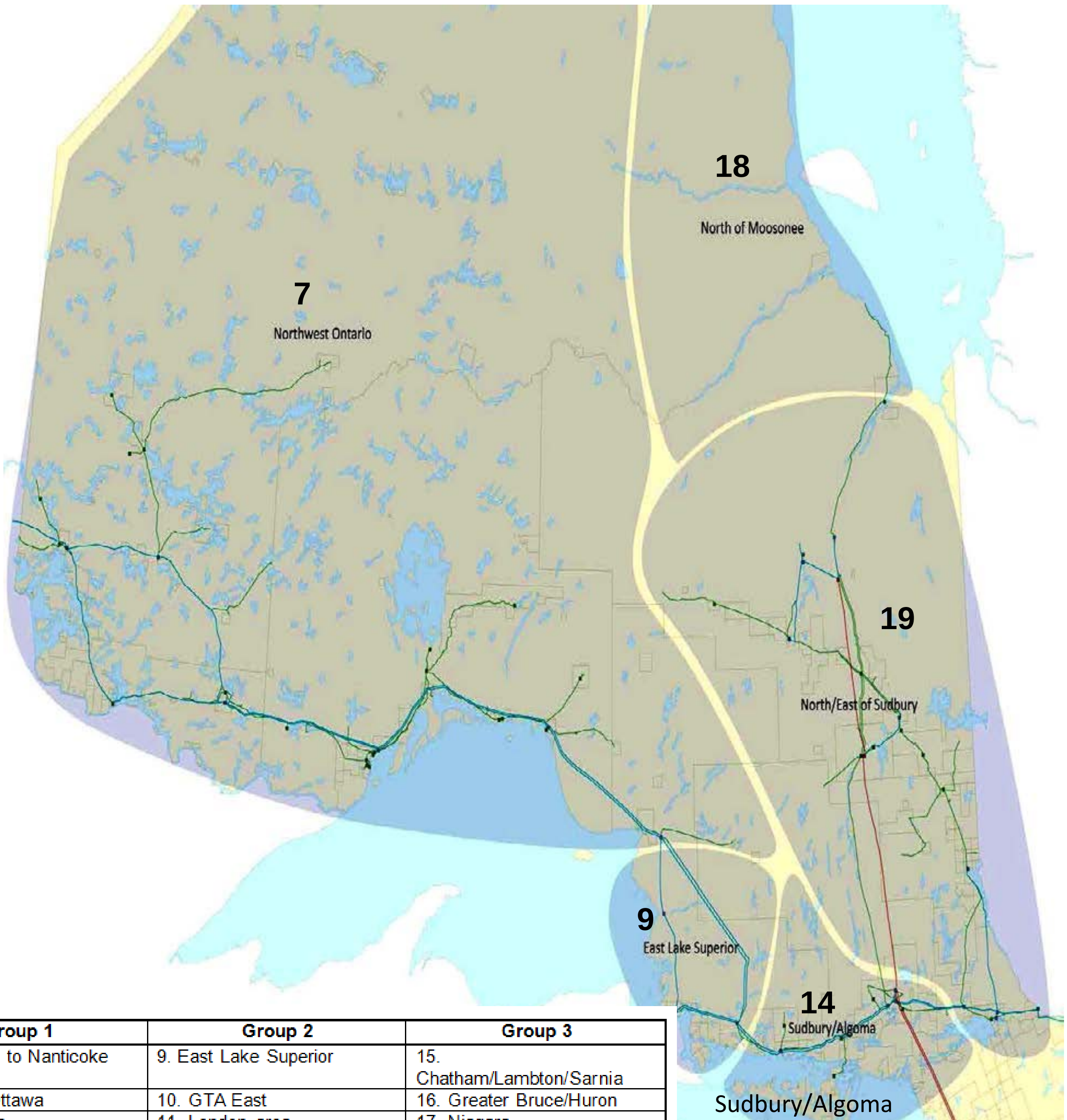
If you should require any further information, please feel free to contact the undersigned at your convenience.

Sincerely,

Tom Sielicki, C.E.T.
V.P. of Engineering
905-353-6016
tom.sielicki@npei.ca

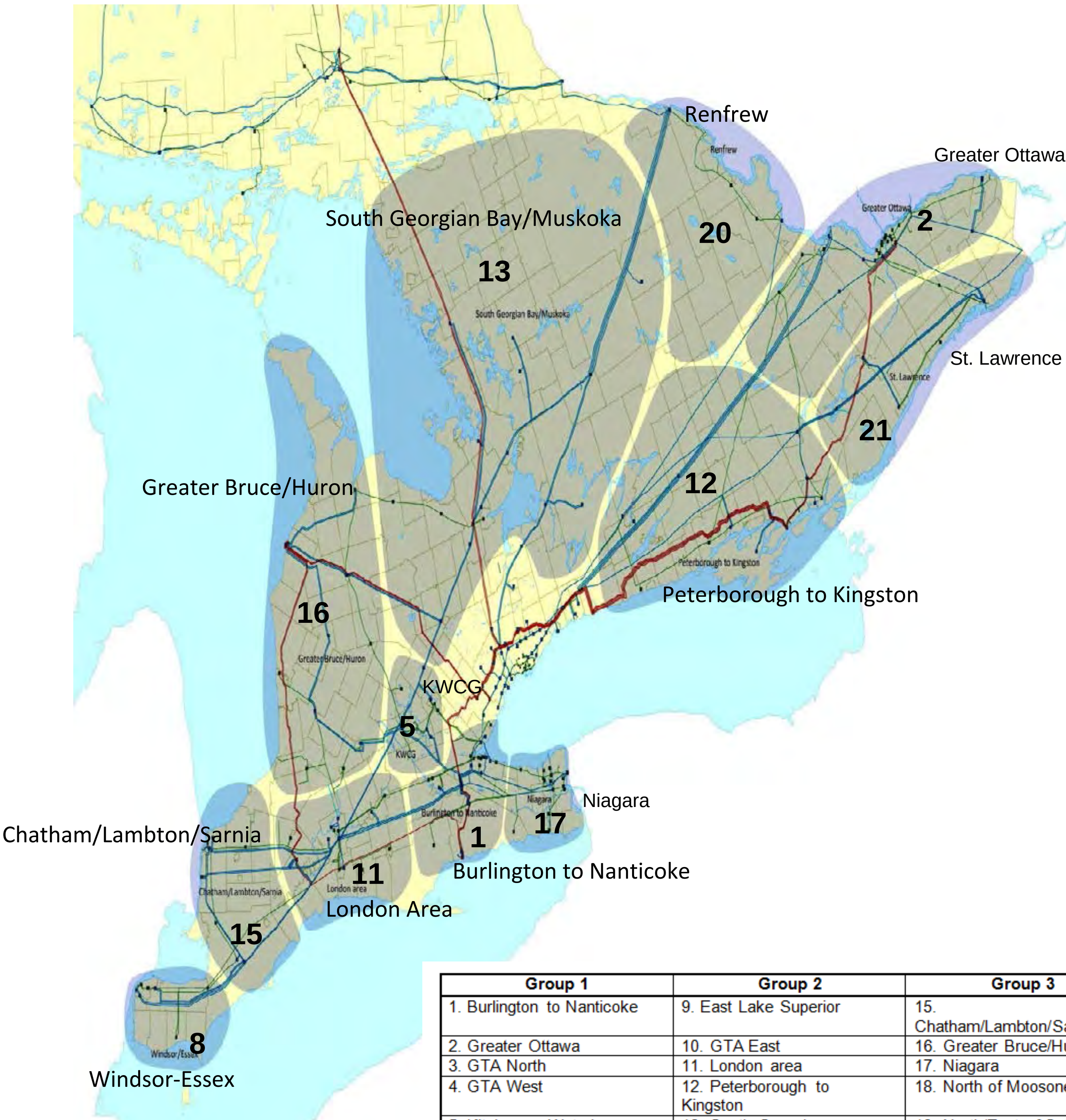
Appendix A: Map of Ontario's Planning Regions

Northern Ontario



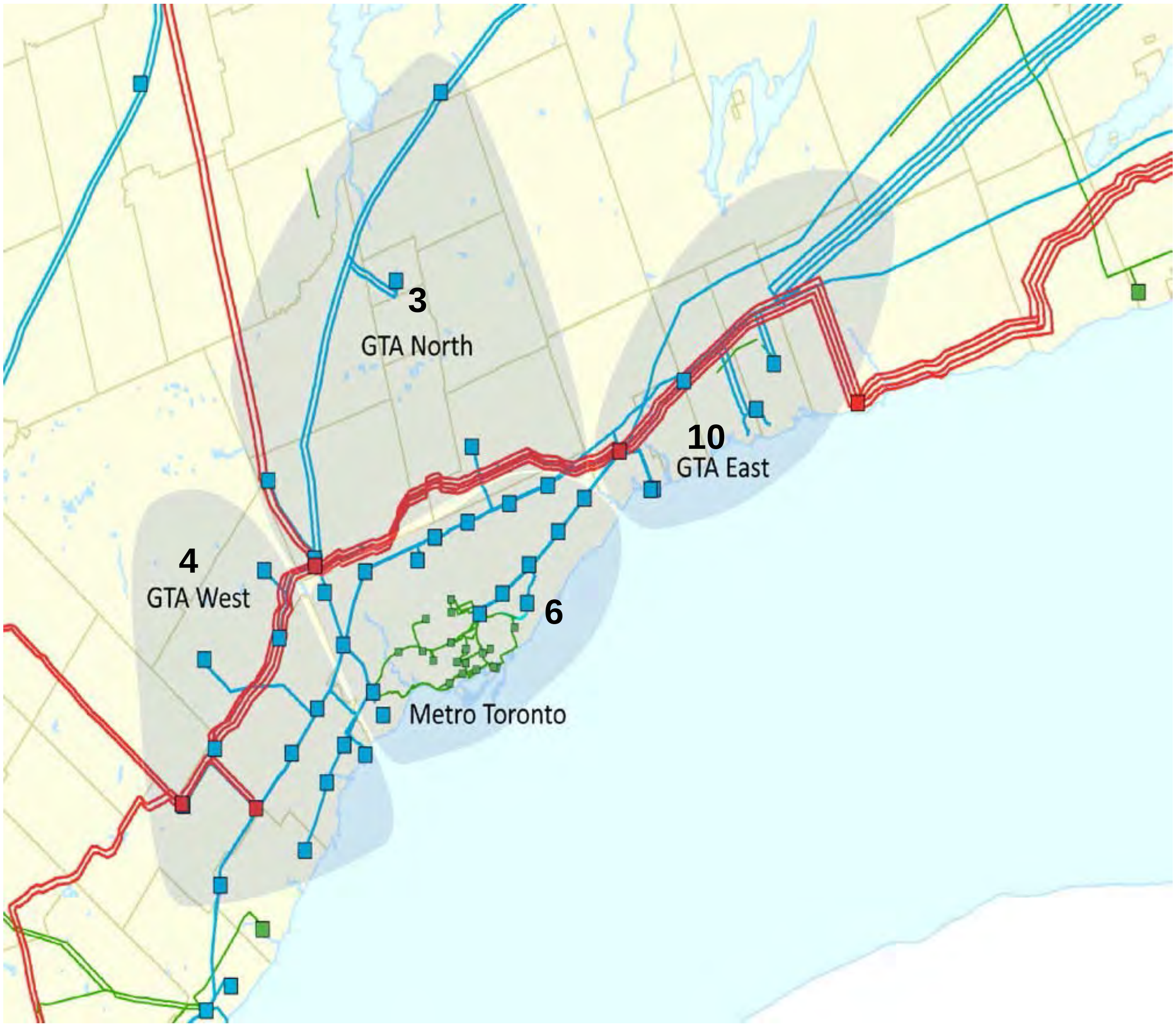
Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc*. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. *Changes to the May 17, 2013 OEB Planning Process Working Group Report.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

APPENDIX C

NPEI Feeder Reliability

2012 Feeder Performance Summary

Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Murray TS	3M17	17,412	6374	2563	6.793	2.487	2.732
Niagara West TS	2508M5	8,303	4324	1297	6.402	3.334	1.920
Murray TS	3M30	5,438	3283	852	6.382	3.853	1.656
Murray TS	3M27	6,054	3301	1083	5.590	3.048	1.834
Kalar TS	KM4	8,116	1476	1649	4.922	0.895	5.499
Murray TS	3M52	1,823	566	376	4.849	1.505	3.221
Kalar TS	KM3	5,714	9465	1591	3.591	5.949	0.604
Stanley TS	12M6	6,599	3837	2274	2.902	1.687	1.720
Allanburg TS	45M7	3,742	292	1321	2.833	0.221	12.815
Murray TS	3M54	4,933	3390	1774	2.781	1.911	1.455
Niagara West TS	2508M4	416	265	151	2.753	1.755	1.569
Stanley TS	12M43	6,817	5191	2514	2.712	2.065	1.313
Vineland DS	4501F1	3,999	1981	1756	2.277	1.128	2.019
Murray TS	3M51	3,453	1903	1606	2.150	1.185	1.814
Beamsville TS	18M4	125	83	61	2.051	1.361	1.508
Stanley TS	12M5	2,294	186	1358	1.689	0.137	12.334
Murray TS	3M56	2,954	3168	1971	1.499	1.607	0.932
Kalar TS	KM7	3,908	1222	2781	1.405	0.439	3.198
Murray TS	3M26	700	176	529	1.324	0.333	3.979
Stanley TS	12M42	1,716	1841	1299	1.321	1.417	0.932
Stanley TS	12M31	1,346	749	1087	1.239	0.689	1.798
Beamsville TS	18M1	5,572	3951	4739	1.176	0.834	1.410
Stanley TS	12M32	1,409	410	1539	0.915	0.266	3.436
Vineland DS	4501F2	1,661	484	1886	0.880	0.257	3.431
Kalar TS	KM8	936	1754	1089	0.859	1.611	0.533
Murray TS	3M29	38	19	47	0.805	0.404	1.991
Murray TS	3M16	140	32	201	0.695	0.159	4.363
Stanley TS	12M41	1,346	450	2155	0.625	0.209	2.992
Beamsville TS	18M2	1,415	910	2447	0.578	0.372	1.555
Murray TS	3M14	144	98	253	0.570	0.387	1.471
Beamsville TS	18M3	116	19	217	0.532	0.088	6.081
Stanley TS	12M33	929	240	1877	0.495	0.128	3.869

2012 Feeder Performance Summary

Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Niagara West TS	2508M2	789	314	2359	0.335	0.133	2.514
Murray TS	3M53	7	1	23	0.304	0.043	6.983
Kalar TS	KM1	108	69	608	0.177	0.113	1.563
Murray TS	3M15	6	5	36	0.171	0.139	1.233
Stanley TS	12M4	75	48	696	0.108	0.069	1.561
Kalar TS	KM2	33	3	854	0.039	0.004	11.011

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Murray TS	3M30	22,864	2240	872	26.220	2.569	10.207
Niagara West TS	2508M5	21,728	6263	1318	16.485	4.752	3.469
Vineland DS	4501F1	28,624	8763	1803	15.876	4.860	3.266
Murray TS	3M16	3,205	962	203	15.787	4.739	3.331
Murray TS	3M56	15,142	3940	1340	11.300	2.940	3.843
Niagara West TS	2508M2	22,077	5263	2448	9.018	2.150	4.195
Beamsville TS	18M1	43,163	24213	4933	8.750	4.908	1.783
Beamsville TS	18M4	483	218	64	7.543	3.406	2.215
Kalar TS	KM8	8,166	2049	1096	7.450	1.870	3.985
Murray TS	3M54	14,983	3210	2194	6.829	1.463	4.668
Niagara West TS	2508M4	889	470	153	5.812	3.072	1.892
Murray TS	3M17	14,168	8073	2610	5.428	3.093	1.755
Murray TS	3M51	8,755	1558	1747	5.011	0.892	5.619
Stanley TS	12M42	6,479	2607	1314	4.931	1.984	2.485
Vineland DS	4501F2	7,688	3427	1931	3.982	1.775	2.243
Stanley TS	12M33	6,198	2382	1887	3.284	1.262	2.602
Stanley TS	12M41	6,718	2782	2160	3.110	1.288	2.415
Stanley TS	12M6	6,751	1520	2288	2.951	0.664	4.441
Stanley TS	12M43	2,469	957	861	2.868	1.111	2.580
Stanley TS	12M32	4,125	2901	1561	2.643	1.858	1.422
Beamsville TS	18M2	6,055	1130	2497	2.425	0.453	5.359
Murray TS	3M27	4,081	1672	1789	2.281	0.935	2.441
Murray TS	3M28	26	15	13	1.968	1.154	1.706
Beamsville TS	18M3	419	265	221	1.898	1.199	1.583
Kalar TS	KM3	3,005	2365	1605	1.872	1.474	1.271
Murray TS	3M14	423	289	252	1.677	1.147	1.462
Kalar TS	KM4	2,513	555	1520	1.653	0.365	4.528
Murray TS	3M52	1,250	381	769	1.625	0.495	3.280
Kalar TS	KM1	808	671	667	1.211	1.006	1.204
Stanley TS	12M1	2,474	2266	2143	1.155	1.057	1.092
Murray TS	3M53	24	7	22	1.108	0.318	3.483

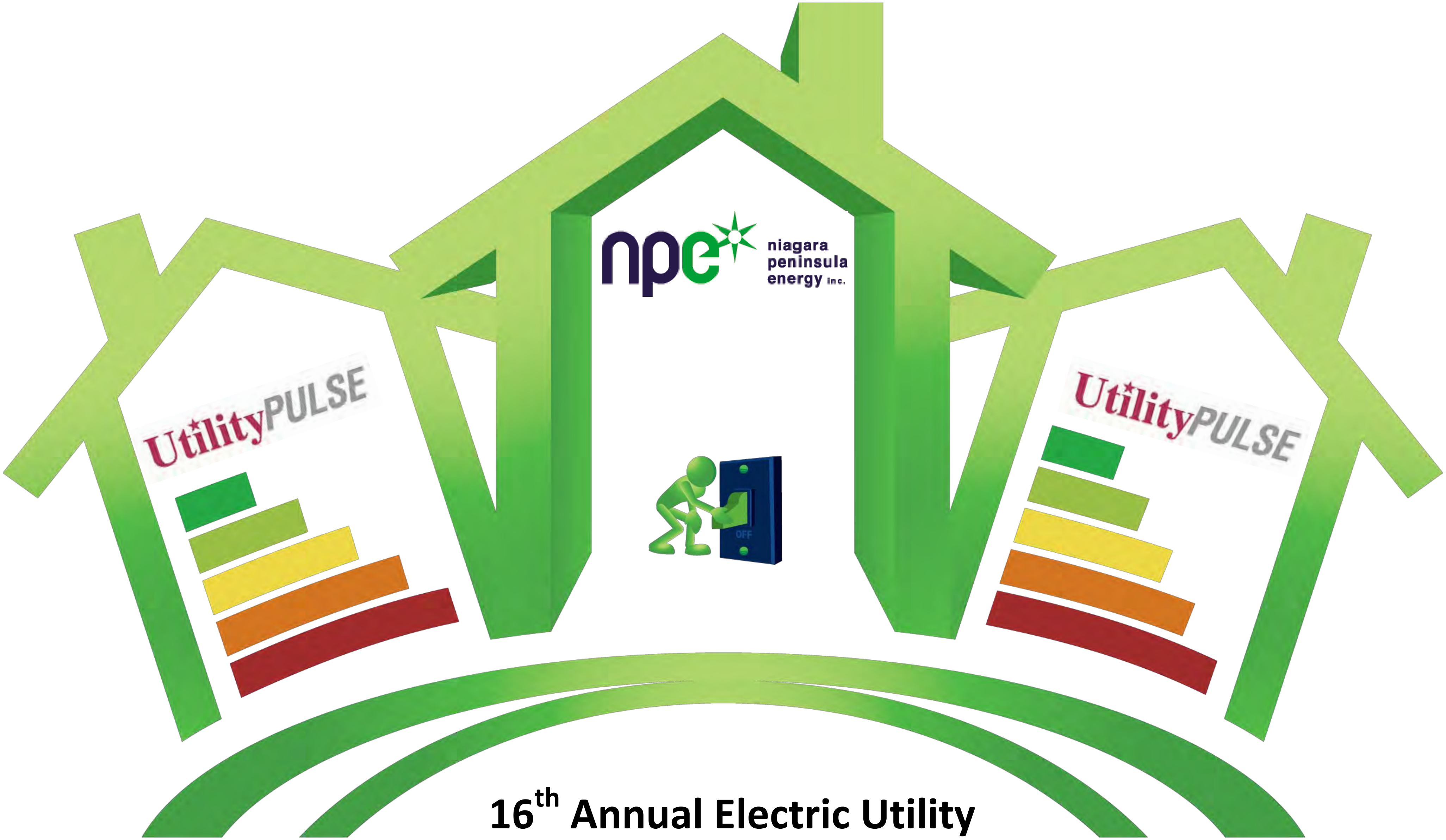
Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Murray TS	3M15	41	22	37	1.104	0.595	1.857
Kalar TS	KM7	2,767	3476	2959	0.935	1.175	0.796
Stanley TS	12M31	1,036	573	1124	0.922	0.510	1.809
Stanley TS	12M4	174	102	221	0.786	0.462	1.702
Murray TS	3M29	36	24	51	0.706	0.471	1.500
Stanley TS	12M5	786	273	1377	0.571	0.198	2.880
Allanburg TS	45M7	744	731	1337	0.557	0.547	1.018
Murray TS	3M26	272	715	601	0.453	1.190	0.380
Kalar TS	KM6	193	22	601	0.322	0.037	8.786
Kalar TS	KM5	79	11	464	0.170	0.024	7.161
Kalar TS	KM2	31	7	995	0.031	0.007	4.381

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

APPENDIX D

NPEI Customer Survey Summary

Niagara Peninsula EnergyInc.



16th Annual Electric Utility
Customer Satisfaction Survey

The purpose of this report is to profile the connection between Niagara Peninsula Energy Inc. (NPEI) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

Rosemarie LeClair, Chair of the Ontario Energy Board, in a recent presentation (Ontario Energy Network, April 28, 2014) said the OEB's consumer centric regulatory framework defines the utility's obligation for planning, obligations for customer engagement and its responsibilities for monitoring and measuring performance results.

EB-2010-0379 Report of the Board: Scorecard Approach (ROB-SA) (March 5, 2014)

Throughout this report are connections to the OEB's Report of the Board. Where possible we have addressed the specifics in the document and, the "spirit" of the Scorecard Approach.

We believe that the data from interviewing over 10,000 electric utility customers so far, in 2014, supports 3 main conclusions:

1- Customers, almost universally, are concerned about the cost of electricity

2- Customers are resilient and can adapt to adversity, in fact, they are very tolerant when a utility goes through a very difficult situation

3- In a utility world that is used to "pushing information out", it has to invest in and hone its competencies in having 2-way interactions with customers.

Reasonable costs

9,943 Ontario survey respondents were asked if they agree or disagree with the following statement *"The cost of electricity is reasonable when compared to other utilities".* 50% agree in 2014, and 62% agreed in 2010. Satisfaction with the utility is about the same in those respective years.

We can also say that issues in the electricity industry, as a whole, show that satisfaction ratings and other important measures are lower in 2014 than they were in 2013. A customer may be upset with the amount that electricity costs, or what is going on in the industry, but that may not translate to being upset with their own local utility.

Data from the 2014 survey shows that respondents who give their utilities high marks for respect, trust, and social responsibility also give their utilities high marks for providing high quality services, and better marks for both cost efficiency and reasonableness of costs.

The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, NPEI has done well.
Overall, NPEI 80% [Ontario 77%; National 80%].

EB-2010-0379 ROB-SA: Comparability

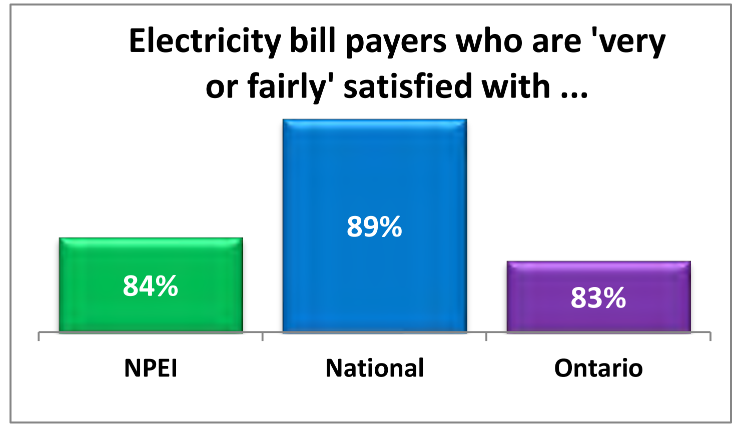
Your 2014 report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Previous year's ratings (where available)

- Ontario LDCs participating in the 2014 survey
- UtilityPULSE database

EB-2010-0379 ROB-SA: Customer Focus

There are 2 identified Performance Categories in the OEB Report, they are Customer Satisfaction & Service Quality. Performance measurements for these areas range from *'relatively easy to attain production statistics'* to '*harder to define and measure qualitative items'*. None-the-less this survey provides you with insights about how customers perceive performance of the utility.



Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus - Customer Satisfaction - Satisfaction Survey Results

Customer satisfaction is one of the measures in the consumer centric regulatory framework. This rating is known as an effectiveness rating as it represents a sum total of perceptions and expectations that a customer has about their utility. Those expectations go far beyond “keeping the lights on”, “billing me properly”, and “restoring power quickly”.

NPEI SATISFACTION SCORES – Electricity customers' satisfaction					
Top 2 Boxes: 'very + fairly satisfied'	**2014**	**2013**	**2012**	**2011**	**2010**
PRE: Initial Satisfaction Scores	84%	-	-	-	-
POST: End of Interview	87%	-	-	-	-

Base: total respondents / (-) not a participant of the survey year

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

Customer Affinity

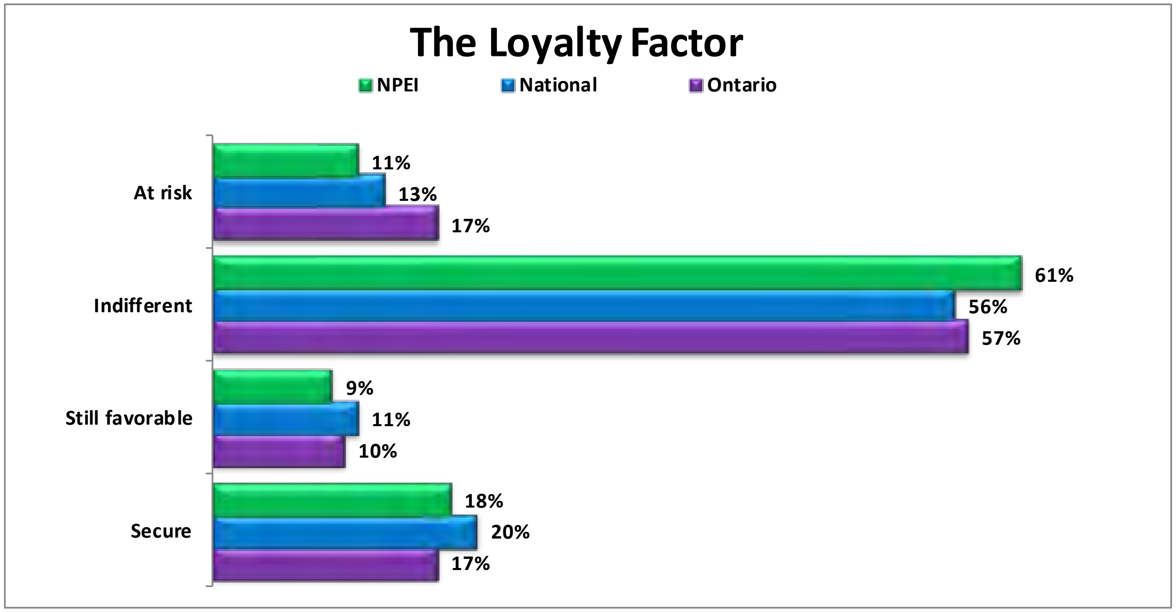
Loyalty, for private industry, is a behaviourial metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
NPEI				
2014	18%	9%	61%	11%

Base: total respondents

Even if customers can't defect, there is enormous value in making more of them loyal. Customers after all make the company's reputation. Reputation is ultimately what customers think – nothing else. To be successful and profitable, companies must take account of how they are perceived because companies do operate in a climate of opinion.

Loyal customers are more likely to see the world the way hydro management sees it. Customers feel their interests and the hydro's are often in common. Our survey results do reveal, loyal customers enhance the value of the utility. One example, 97% of Secure customers agree that overall NPEI 'provides excellent quality services' versus 62% of At Risk customers.



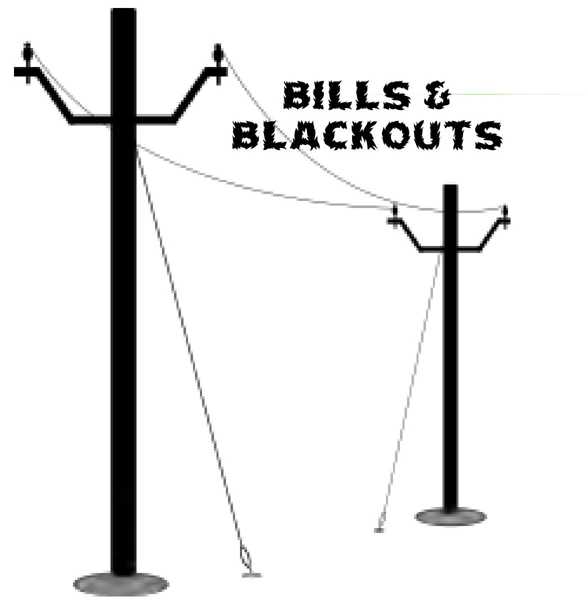
Base: total respondents

Utilities benefit from a trusted relationship with their empowered Customers. Higher levels of trust are the hallmarks of Secure customers. When people interact, either face-to-face, by telephone or on-line, if people do not trust each other, the interaction is not going to be efficient. Trust improves the

speed at which the interaction can be accomplished. At Risk customers recall experiencing more outages and more billing problems than Secure customers. What makes matters worse is, At Risk customers are about 2X more likely to contact the utility to deal with it.
None-the-less problems will happen.

The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and more importantly, how it deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those which cause the most concern with customers.



Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	NPEI	National	Ontario
2014	51%	47%	49%
2013	-	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

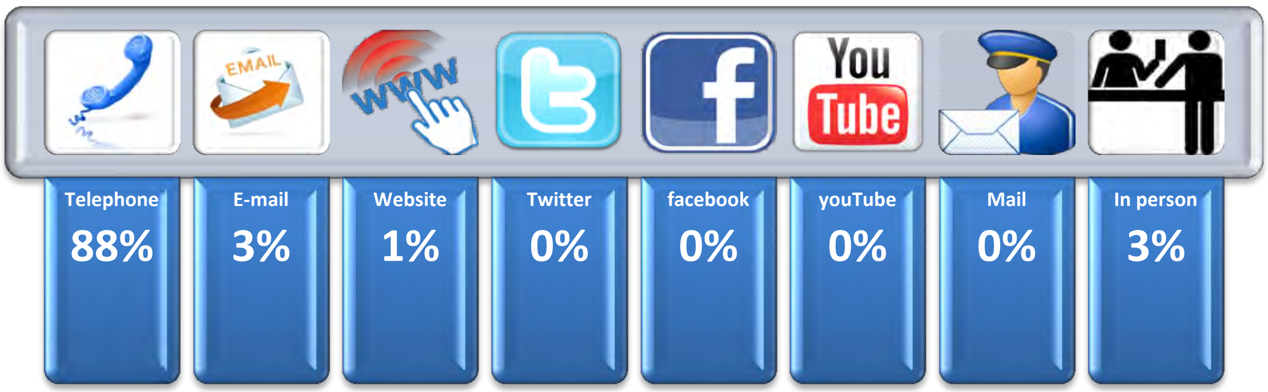
Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	NPEI	**National**	**Ontario**
2014	18%	16%	25%
2013	-	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year

What method did you use to contact your electric utility when you had a problem?

Base: data from the full 2014 database



Customers may prefer a particular communication channel today (i.e., 88% telephone), however, that does not mean the customer who prefers the telephone will not want, or eventually want another channel for communications. In addition, there could be variances in preferences based on the type of issue or transaction.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – Billing Accuracy

There is a difference between what a customer believes is a billing problem versus a technical or production level measurement. Without the benefit of production level numbers, 84% of respondents 'agree strongly + somewhat' that the utility has "accurate billing". The Ontario benchmark rating is 77%.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – First Contact Resolution

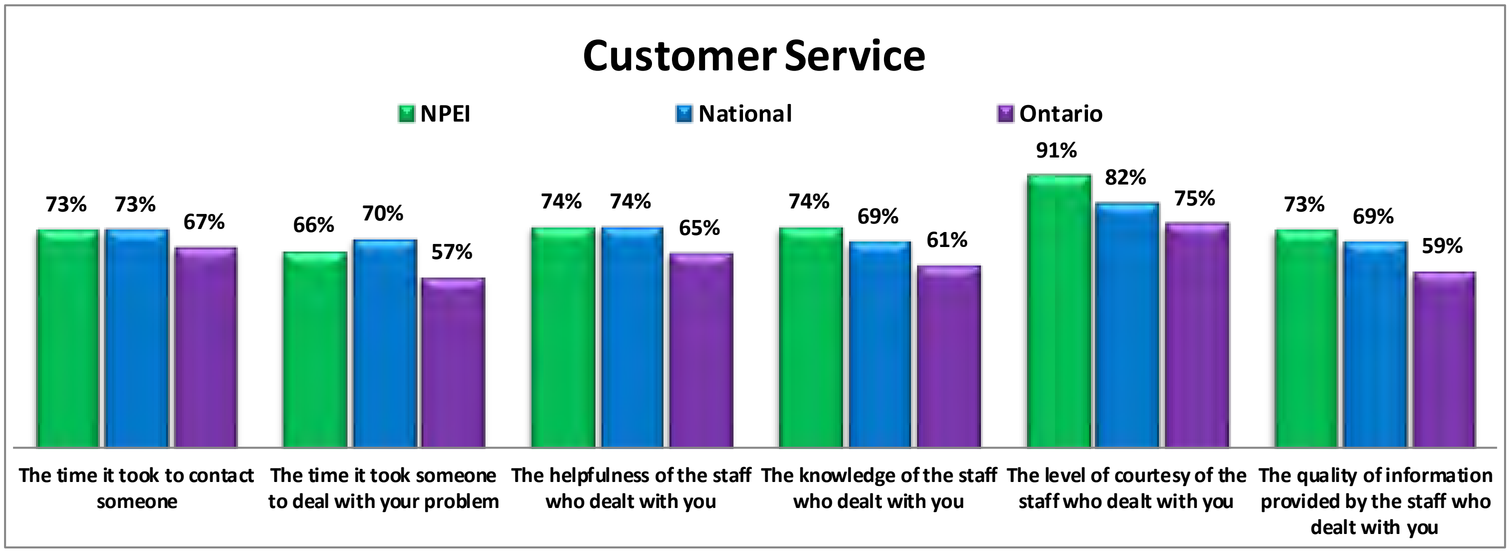
This performance measure is not defined in the EB-2010-0379 ROB-SA March 5, 2014 document. First contact resolution is an outcome base measurement which is affected by: type of problem, competency levels of staff, empowerment levels of staff, and organization culture to name a few.

Your 2014 survey gives you the following information from respondents:

1- Satisfaction with the contact experience
2- A problem solved rating
3- A Customer Experience Performance rating (CEPr)

Satisfaction with the contact experience

When there are problems, how they are handled can validate or invalidate a customer's perception about the utility's competency in handling the problem, and in running the operation. Here is how Customers, who contacted your LDC, rated their one-on-one transaction.



Base: total respondents who contacted the utility

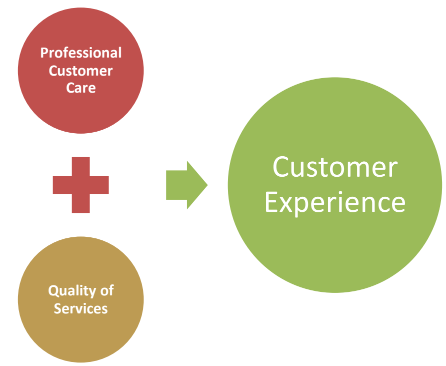
Customer expectations are on the rise and continue to change. Customers expect their utility to have customer care practices and services that are in-line with any other organization that is important to their everyday life. Setting realistic expectations and consistently delivering to those expectations are keys to higher levels of Customer satisfaction. The setting of customer expectations is tough, but the harder part is to deliver consistency.

Overall satisfaction with most recent experience			
	NPEI	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	76%	75%	62%

Base: total respondents who contacted the utility

Problem solved rating

Respondents who said that they contacted the utility were also asked "Do you consider the problem solved or not solved?" 67% of your LDC's respondents said the problem was solved. The Ontario benchmark rating is 61%.



Customer Experience Performance rating (CEPr)

What do customers anticipate contact will be with their local utility when they have a problem? Will it be adversarial, or cooperative, or pleasant, etc. High numbers in CEPr indicate that a large majority of customers would agree that their next contact will be a good or positive one.

Customer Experience Performance rating (CEPr)			
	NPEI	**National**	**Ontario**
CEPr: all respondents	82%	82%	79%

Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus – Service Quality

The three performance measures identified are all time based measures. They are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures. In addition to time, there are other dimensions of Service Quality that Customers value.

Customer Service Quality

Top 2 boxes, 'strongly + somewhat agree'	NPEI	National	Ontario
Deals professionally with customers' problems	82%	82%	78%
Pro-active in communicating changes and issues affecting Customers	76%	74%	73%
Quickly deals with issues that affect customers	79%	79%	74%
Customer-focused and treats customers as if they're valued	76%	74%	72%
Is a company that is 'easy to do business with'	81%	79%	75%
Cost of electricity is reasonable when compared to other utilities	58%	60%	55%
Provides good value for money	68%	67%	63%
Delivers on its service commitments to customers	85%	84%	82%

Base: total respondents with an opinion

EB-2010-0379 ROB-SA: Operational Effectiveness

With the exception of the Public Safety measure, which is yet to be defined, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. Though customers may not have the benefit of numbers, they do have a perception.

Management Operations

Top 2 boxes, 'strongly + somewhat agree'	NPEI	National	Ontario
Provides consistent, reliable electricity	87%	89%	86%
Quickly handles outages and restores power	85%	86%	83%
Makes electricity safety a top priority for employees and contractors	88%	89%	87%
Operates a cost effective electricity system	68%	69%	62%
Overall the utility provides excellent quality services	84%	83%	80%

Base: total respondents with an opinion

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

NPEI's UtilityPULSE Report Card®

Performance

	CATEGORY	NPEI	National	Ontario
1	**Customer Care**	**B**	**B+**	**B**
	Price and Value	C+	B	C+
	Customer Service	B+	B+	B
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	B+	A	B+
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A	A	A
	OVERALL	**B+**	**B+**	**B+**

Base: total respondents

Corporate Image

Reputation, image, brand have to be actively managed. Positive impressions beget positive perceptions. Marketing communication includes positioning the utility in a way that makes customers want your utility and its services. Every utility has a brand, why not have the brand you want?

Attributes strongly linked to a hydro utility's image

	NPEI	National	Ontario
Is a respected company in the community	85%	81%	78%
A leader in promoting energy conservation	81%	78%	77%
Keeps its promises to customers and the community	82%	79%	76%
Is a socially responsible company	83%	78%	77%
Is a trusted and trustworthy company	84%	82%	77%
Adapts well to changes in customer expectations	72%	71%	68%
Is 'easy to do business with'	81%	79%	75%
Provides good value for your money	68%	67%	63%
Overall the utility provides excellent quality services	84%	83%	80%
Operates a cost effective hydro-electric system	68%	69%	62%

Base: total respondents with an opinion

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction. The industry is obsessed with rational concerns about customer behaviour, but the real motivation for customer behaviour is emotional, not rational.

What do customers think about electricity costs?

Ask a utility customer – anywhere in the province of Ontario – what do they think about electricity, there is a very high probability they will say electricity costs are too high or too expensive. For customers who said that they had a billing problem in the last 12 months, and stated that the problem was "high bills" or "high rates or charges", there was very little variability between customers who could be called Secure, Favourable, Indifferent or At Risk. There was also very little variability between age groupings or income groupings.

Our survey database shows 50% more customers in 2014 citing complaints with "high bills" or "high rates or charges" than in 2010. There is a growing concern over electricity costs, especially as it relates to its portion of a household budget. This means the industry needs to monitor "ability to pay".

Is paying for electricity a worry or major problem …

	NPEI	National	Ontario
Not really a worry	57%	69%	59%
Sometimes I worry	31%	20%	26%
Often it is a major problem	6%	7%	11%
Depends	2%	3%	2%

Base: total respondents

Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and insights, on a number of subjects such as e-care, e-billing, conservation and more.

Electric Industry Knowledge & SMART Grid

Beyond knowing that they need electricity to maintain their day to day activities, does the average person feel that they are actually knowledgeable about the electric utility industry?

Knowledge level about the electric utility industry	
	Ontario
Extremely knowledgeable	2%
Very knowledgeable	11%
Moderately knowledgeable	47%
Slightly knowledgeable	26%
Not very knowledgeable	14%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Two-thirds (60%) of those polled in the Ontario Benchmark survey considered themselves moderately to extremely knowledgeable about the electric industry.

While it is evident that the SMART grid is still not a much talked about concept, only 34% have a basic or good understanding of what it is, oddly enough, 60% still think that it is important to pursue SMART grid implementation. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.

Level of knowledge about the SMART Grid

	Ontario
I have a fairly good understanding of what it is and how it might benefit homes and businesses	9%
I have a basic understanding of what it is and how it might work	25%
I've heard of the term, but don't know much about it	36%
I have not heard of the term	29%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Efforts to reduce energy consumption

Do customers believe there is a real pay-off for trying to reduce their energy consumption? Does this impact overall efforts to reduce consumption? Respondents were asked *"How active have you been in trying to reduce your electricity consumption?"* (Base: total respondents in the Ontario Benchmark survey)

- 94% feel they are "very + somewhat active" in trying to reduce electricity consumption, and
- 81% of those do believe their efforts have resulted in reduced energy consumption, of which
- 44% estimate that they were able to offset an energy consumption reduction of more than 10%, and
- 72% believe that these efforts translated to savings on their electricity bills.

Level of Activity in trying to reduce electricity consumption	Ontario
Very active	52%
Somewhat active	42%
Neither proactive or inactive	0%
Not active	2%
Not very active	3%

Base: total respondents in the Ontario Benchmark survey

Estimate of percentage reduction in consumption	Ontario
1 – 2 %	5%
3 – 5 %	10%
6 – 8 %	4%
9 – 10 %	15%
More than 10%	44%
Don't know	21%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Active efforts have reduced energy consumption

81%

16%

Base: total respondents in the Ontario Benchmark survey who have been active in trying to reduce energy consumption

Efforts to conserve have translated into savings on your electricity bill

72%

24%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Energy Conservation & Efficiency

Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and *energy saving through changes in customer awareness and behaviour.*

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	19%	9%	70%	1%
Install timers on lights or equipment	12%	50%	35%	2%
Shift use of electricity to lower cost periods	22%	17%	58%	3%
Install window blinds or awnings	12%	27%	60%	2%
Install a programmable thermostat	13%	25%	60%	2%
Have an energy expert conduct an energy audit	9%	71%	16%	4%
Removing old refrigerator or freezer for free	14%	44%	38%	4%
Join the peaksaverPLUS™ program	15%	49%	21%	16%
Replacing furnace with a high efficiency model	12%	33%	52%	4%
Replacing air-conditioner with a high efficiency model	14%	38%	44%	4%
Use a coupon to purchase qualified energy saving products	35%	39%	22%	5%

Base: An aggregate of respondents from 2014 participating LDCs

E-care and E-billing

Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before.

Do you have access to the internet?	
	Ontario LDCs
Yes	87%
No	13%

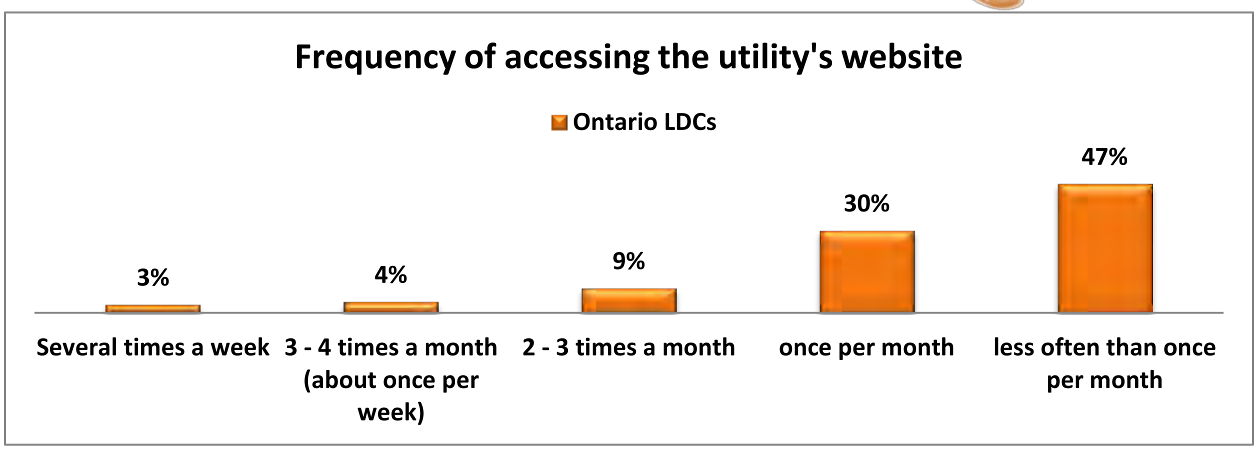
Base: An aggregate of respondents from 2014 participating LDCs

Over the past six months have you accessed your local utility website?

Base: An aggregate of respondents from 2014 participating LDCs

29%

70%



Base: An aggregate of respondents from 2014 participating LDCs

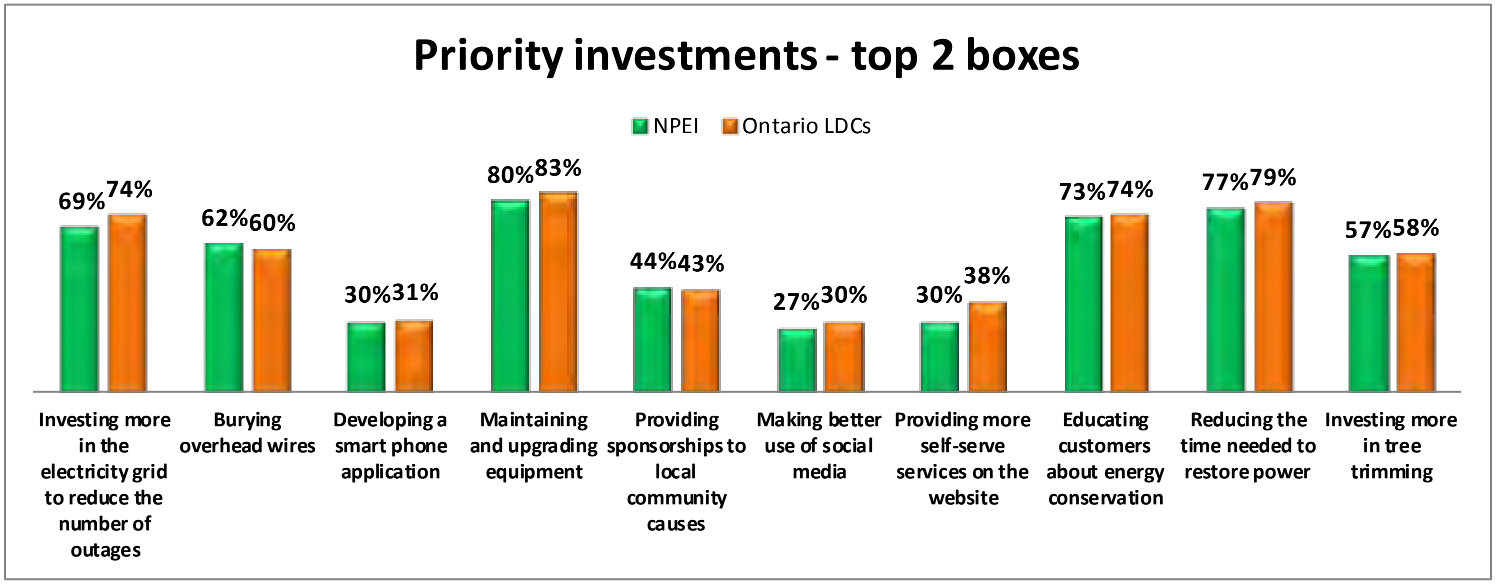
Likelihood of using the internet for future customer care needs for things such as:	
Top 2 Boxes: ‘very + somewhat likely’	**Ontario LDCs**
Setting up a new account	31%
Arranging a move	38%
Accessing information about your bill	55%
Accessing information about your electricity usage	54%
Accessing energy saving tips and advice	45%
Accessing information about Time Of Use rates	51%
Maintaining information about your account or preferences	51%
Paying your bill through the utility’s website	32%
Getting information about power outages	47%
Arranging for service	40%

Base: An aggregate of respondents from 2014 participating LDCs

As society becomes increasingly more familiar with technology it will become a more popular medium for giving and receiving information. One could also say, demographics will also put more pressure on the technology channels. Unfortunately, customers adopt technology on their own timetable. This causes the utility to continue to improve existing channels while building the technological channels wanted by some today, but by the year 2020, demanded by many. Will your utility be ready?

Priority Investments

While regulation and reliability are top concerns in the utility industry, aging infrastructure is now a top operational concern. Customers agree with industry insiders that infrastructure renewal is a high priority. This year, respondents were asked for their views about prioritizing investments.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local

Some findings shown above correlate with some of the suggestions made by respondents on things the utility could do to improve. Percentage of comments received from all Ontario respondents were:

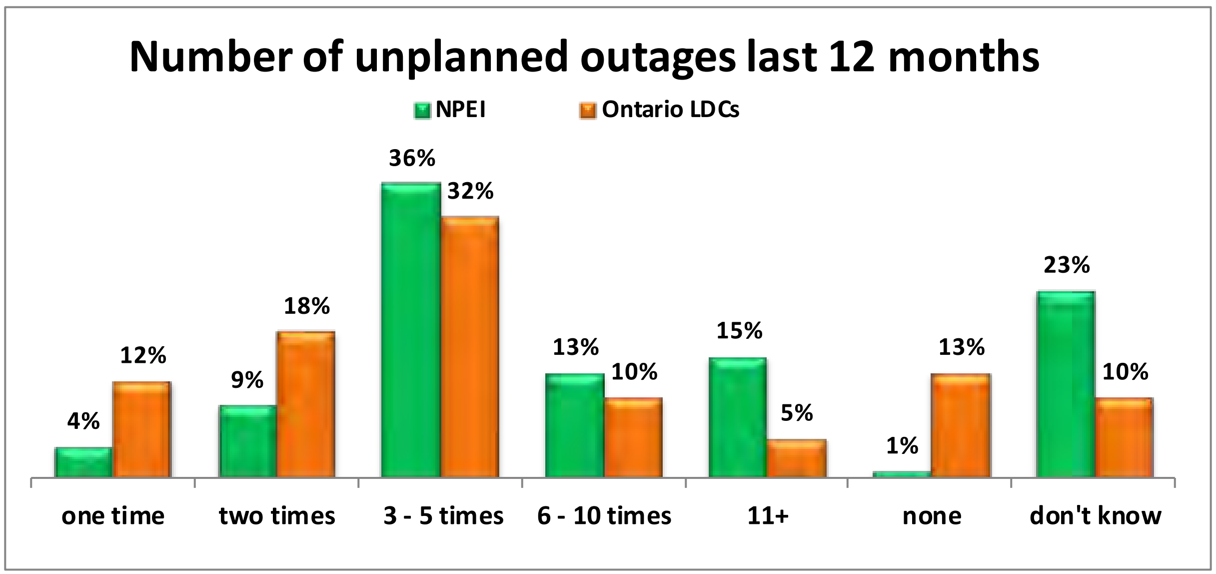
- 14% improve reliability (10% in 2010)
- 11% better maintenance (3% in 2010)

- 10% better communication (7% in 2010)

Outage Management

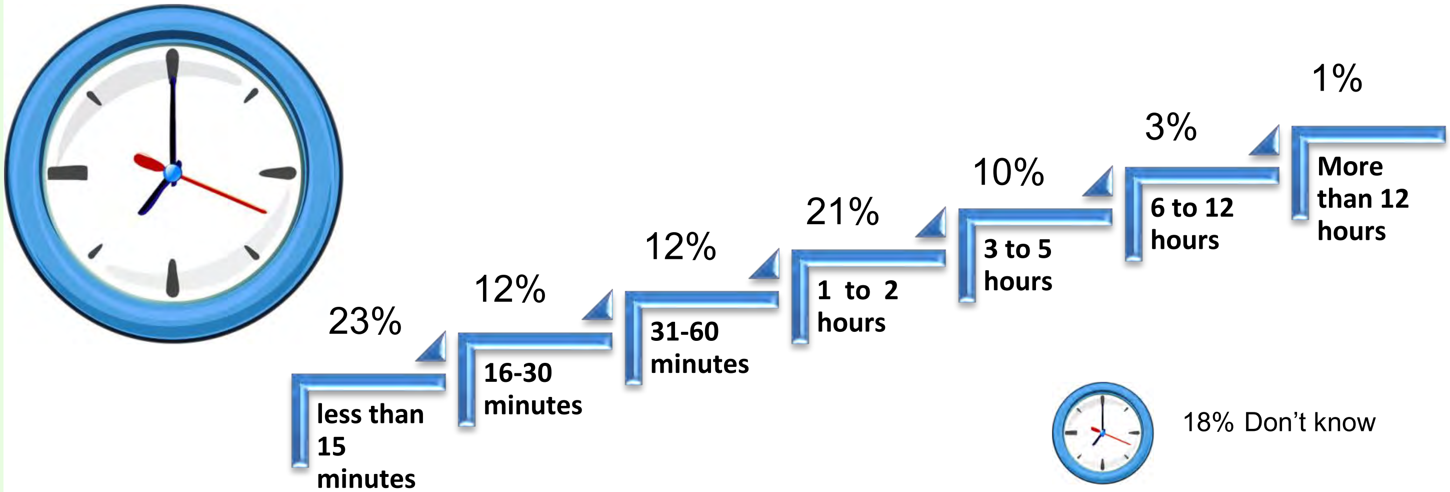
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenario and under worst case scenarios there could be safety and financial consequences.

However, one thing for certain, no matter what the scenario happens to be, customers are expecting their utility to keep them continually updated on the status of outages. Most importantly, and top priority, is to know the estimated restoration time. They also want to know the cause of the outage because they do not want to be a frequent outage customer.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

When an unplanned outage occurs, how long, on average, is the outage?



Base: 90% of total respondents from the local utility

How a utility chooses to handle, manage and communicate with customers during an outage situation does affect customers' satisfaction with their utility. Customers want timely, accurate and relevant information about an outage and customers expect a utility to use various communication channels to ensure their message is getting out there. This means not only obtaining information via the call centre and IVR but customers have increasing expectations for proactive two-way communication through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

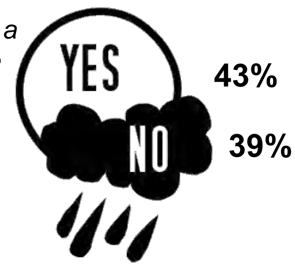
Inability to provide the above information accurately and in a timely manner will result in customer complaints, increased call volumes to your call centres, create unwanted public and media attention, and negatively impact customer satisfaction.

Utility's effectiveness during an unplanned outage		
Top 2 Boxes: 'very + somewhat effective'	**Ontario LDCs**	**NPEI**
Responding to questions	61%	61%
Providing a reason for the outage	61%	51%
Providing an estimate when power will be restored	60%	54%
Responding to the power outage	81%	80%
Restoring power quickly	85%	86%
Communicating updates periodically	64%	56%
Posting information to the website	35%	25%
Using media channels for providing updates	53%	42%

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

On December 20, 2013, a severe ice storm struck the central and eastern portions of Canada and the northeastern United States. The storm's devastation caused major damage to utility distribution lines, towers, transformers, poles and entire substations and resulted in large scale outages and blackouts for long periods of time. The data suggests that customers are both tolerant and understanding when major outages take place.

Did you have a power outage during the ice storm in December 2013?



Base: total respondents

Percentage of Respondents who contacted their utility about the ice storm power outage	NPEI
Yes	24%
No	73%

Base: total respondents affected by the ice storm

NPEI
Length of outage (during Ice Storm 2013)

Less than 2 hours	2 – 4 hours	4+ hours or ½ day	12-18 hours or ½ - ¾ day	19-24 hours or 1 day	1 to 1.5 days	1.6 to 2 days	More than 2 days
21%	24%	23%	2%	2%	1%	1%	1%

Base: total respondents affected by the ice storm

Using social media and multi-channel communication modes still appear to be the exception when it comes to customers contacting their utilities. Results from this year's survey indicate that the telephone is still the most used and the preferred method of contact. Overall, 87% of all Ontario respondents affected by the ice storm who informed their local utility they were experiencing a power outage did so via telephone; 95% of NPEI's respondents used the telephone to contact their utility.

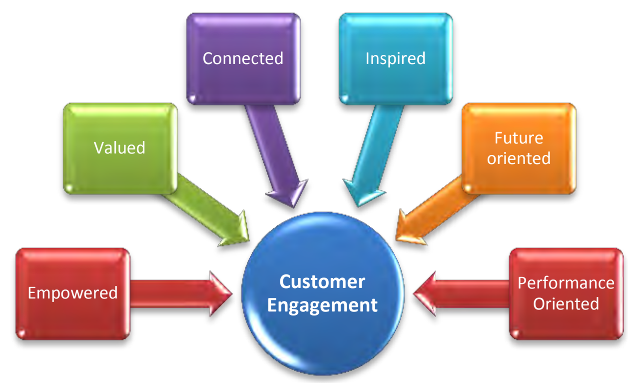
In your view, what is an acceptable period of time to go without electricity in situations like the ice storm?

Base: total respondents affected by the ice storm

•None (the power shouldn't be going out)	11%
•Less than 2 hours	20%
•2 - 4 hours	29%
•4+ hours or 1/2 day	17%
•12 - 18 hours or 1/2 day to 3/4 day	3%
•19 - 24 hours or 1 day	3%
•1 to 1.5 days	2%
•1 .6 to 2 days	1%
•More than 2 days	0%

Customer Centric Engagement Index (CCEI)

The EB-2010-0379 ROB-SA report includes the following: "better engage with their customers to better understand and respond to their needs…" Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers. We call this an activity based definition of engagement. Asking 100 people to complete a survey is an engagement activity.



This survey also provides you with an emotional look at engagement. The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggests that there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

Utility Customer Centric Engagement Index (CCEI)

	NPEI	National	Ontario
CCEI	78%	79%	76%

Base: total respondents

In a world of chaos and confusion what will a customer do? Find someone to help. In the electricity industry, the vast majority of customers turn to, and rely on, their local utility. Knowing that customers will turn to their electric utility requires utilities to really know their customers. Not easy when customer expectations continue to shift.

The shift is on. 15 years ago a utility could think about their customers in terms of usage, now they have to think about them in terms of personas (i.e., customer type). Currently, customer segmentation, for most utilities, consists of a number of "personas". While this may be adequate today, in order to achieve high customer participation in programs and to optimize business processes there will be a need for granular targeting of communications.

Most utilities are quite comfortable "pushing" out communications in a one-way world. However, the shift is on because the new channels are 2-way; even without the new channels customers are expecting 2-way dialogue. The impact on a utility's marketing-communications is significant.

Value is what a customer perceives they get in exchange for what they give up. The real challenge is educating customers on the value they receive. In the absence of a value proposition the primary thing people will talk about is cost.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2014 customer satisfaction survey derived from speaking with 405 NPEI customers [May 14 - 24, 2014]. The electric utility business has demanding customers with high expectations.

UtilityPULSE

Sid Ridgley

Simul/UtilityPULSE

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June, 2014

Simul

UtilityPULSE

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. We've done work for the Ontario Electrical League, the Ontario Energy Network, and both large and small utilities. For sixteen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	Focus Groups, Surveys, Polls, Diagnostics	Customer Service Excellence
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP, MBA

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

APPENDIX E

2014 Asset Condition Assessment (ACA)

NIAGARA PENINSULA ENERGY INC.
DISTRIBUTION ASSET CONDITION REPORT - 2014

September 19, 2014

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

NIAGARA PENINSULA ENERGY INC.
DISTRIBUTION ASSET CONDITION REPORT - 2014

Kinectrics Report: K-418647-RA-0001-R0

September 19, 2014

Prepared by:

Katrina Lotho, BESc, BSc., P.Eng
Senior Engineer

Reviewed and Approved by:

Y. Tsimberg

Yury Tsimberg, M.Eng, P.Eng
Director – Asset Management

Dated: Sep. 19/14

To: Niagara Peninsula Energy Inc.
7447 Pin Oak Dr.
Niagara Falls, ON
L2E 6S5

Revision History

Revision Number	Date	Comments	Approved
R0	September 19, 2014		Yury Tsimberg

EXECUTIVE SUMMARY

In 2011 Niagara Peninsula Energy Inc. (NPEI) determined a need to perform a condition assessment of its key distribution assets. NPEI selected and engaged Kinectrics Inc. (Kinectrics) to perform the Asset Condition Assessment (ACA). In 2014, Kinectrics was tasked with performing a subsequent assessment.

The asset groups included in the 2014 ACA are as follows: power transformers, large pad-mounted transformers, pole-top transformers, wood poles, standard pad-mounted transformers, pad-mounted switchgear, main feeder and distribution underground cables. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

It was found that power transformers, pole-top transformers, and wood poles have the highest percentages of units in poor to very poor condition. Also of significance is the pad-mounted switchgear group because over half of all samples were in no better than fair condition. In terms units flagged for action, it was found that the most significant quantities flagged for action in the near future belong to pole-top transformers and wood poles.

An audit assessing the ACA changes between 2011 and 2014 was conducted. The following aspects were compared: Health Index formula, population and sample size, and health index distribution. Following is a summary of the findings:

- Between 2011 and 2014, the Health Index formulas for many asset groups were refined to include new data, more representative failure curves, and/or refined condition criteria.
- The sample sizes for wood poles, standard pad-mounted transformers, and pad-mounted switchgear improved significantly.
- There was a significant improvement in the overall health of power transformers. This is likely a result of new transformer installations in Smithville DS and Green Lane DS.

The results presented in this study are based solely on asset condition as determined by available data. Note that there are numerous other considerations that may influence NPEI's planning process. Among these are obsolescence, system growth, corporate priorities, technological advancements, etc.

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I INTRODUCTION

Niagara Peninsula Energy Inc. (NPEI) is a local distribution company (LDC) that serves over 51,000 customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham and Township of West Lincoln.

NPEI is jointly owned by Niagara Falls Holding Corporation and Peninsula West Power Inc. Niagara Falls Holding Corp. is wholly owned by the City of Niagara Falls. Peninsula West Power Inc., which is also a Holding Company, is jointly owned by the Town of Lincoln, the Town of Pelham and the Township of West Lincoln. NPEI is governed by an eight member Board of Directors and is licensed by the Ontario Energy Board (OEB).

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 100 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 has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

In 2011 Kinectrics performed an Asset Condition Assessment (ACA) on NPEI's key distribution assets. Kinectrics was again tasked with performing an ACA for NPEI in 2014. This report presents the results of the 2014 ACA.

This Asset Condition Assessment Report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

I.1 Objective and Scope of Work

The scope of work includes an assessment of the following asset classes:

- Power Transformers
- Large Pad-mounted Transformers
- Pole-top Transformers
- Wood Poles
- Standard Pad-mounted Transformers
- Pad-mounted Switchgear
- Underground Cables
    - Main Feeder
    - Distribution

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year condition-based Flagged for Action Plan
- Identifying and prioritizing the data gaps for each group

For each asset category, the Health Index formulation, Health Index distribution, condition-based Flagged for Action Plan, and a data assessment in terms of the data availability indicator (DAI) and data gap analysis are given.

I.2 Data Source

The data used in this study was provided to Kinectrics by NPEI are summarized as follows:

Asset Category	File Name
Power Transformers (station and large)	1_Power_Transformers_Hydro_Owned.xls
	2_Power_Transformers_Maintenance_Attributes.xls
	Tests_01Jan1965_12Aug2014.xls
Pole-top Transformers	1a_Polemount_Distribution_Stepdown_TX.xls
	2a_Polemount TX Inspection Results.xls
Wood Poles	1_Poles_Hydro_Owned.xls
	2_Pole_Inspections_Hydro_Owned.xls
Standard Pad-mounted Transformers	1a_Padmount_Transformers_Hydro_Owned.xls
	2_Padmount_SG_Inspections_Hydro_Owned.xls
Pad-mounted Switchgear	1_Padmount_SG_Hydro_Owned.xls
	2_Padmount_SG_Inspections_Hydro_Owned.xls
UG Cables	1a_Primary_UG_Cable_Hydro_Owned.xls

I.3 Deliverables

The deliverable in this study is a Report that includes the following information:

- For each asset category the following are included (Appendix A: Results and Findings for Each Asset Category):
    - Health Index formulation
    - Age distribution
    - Health Index distribution
    - Condition-based Flagged For Action Plan
    - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis
- An audit describing the key changes between 2011 and 2014

II INTRODUCTION

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a condition-based Flagged for Action Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index 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 provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or intervention in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a power transformer parameter called "Oil Quality" may be a composite of parameters such as "moisture", "acid", "interfacial tension", "dielectric strength" and "color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

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

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

Equation 1

where

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

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.

De-Rating multipliers are applied to the calculated HI. These may be used to represent the impact of non-condition issues such as design or operating environment.

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index $\leq$ 30%
Poor	30 < Health Index $\leq$ 50%
Fair	50 < Health Index $\leq$70%
Good	70 < Health Index $\leq$85%
Very Good	Health Index > 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 **Condition Based Flagged for Action Plan**

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides a good model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f = failure rate per unit time
t = time
γ, β = constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in failure rate studies of multiple power system asset groups, the following variation of the failure rate formula has been adopted:

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

Equation 4

f = failure rate of an asset (percent of failure per unit time)
t = age (years)
α, β = constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

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

Equation 5

P_f = cumulative probability of failure

Different asset 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 to control 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.

Consider, for example, an asset class where at the ages of 45 and 65 the asset has cumulative probabilities of failure of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 72 and 0.131 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{-\alpha\beta})/\beta} \; = \; 1 - e^{-(e^{0.131(t-72)} - e^{-9.432})/0.131}$$

The failure rate and probability of failure graphs are as shown:

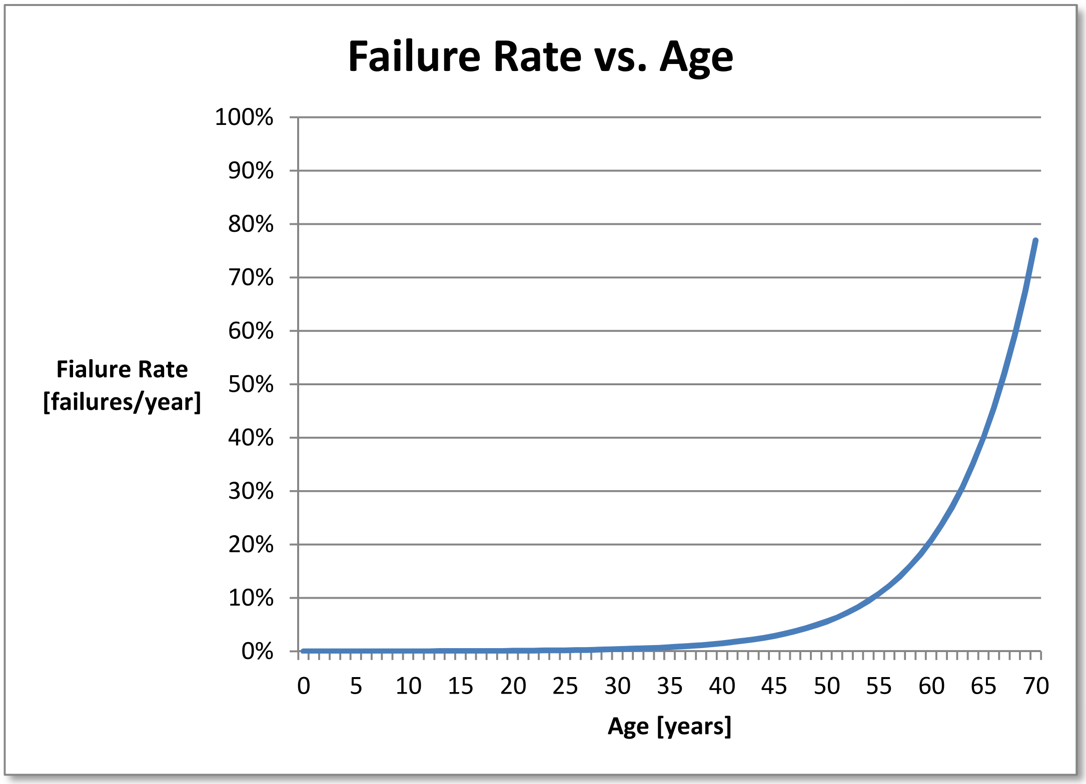


Figure II-1 Failure Rate vs. Age

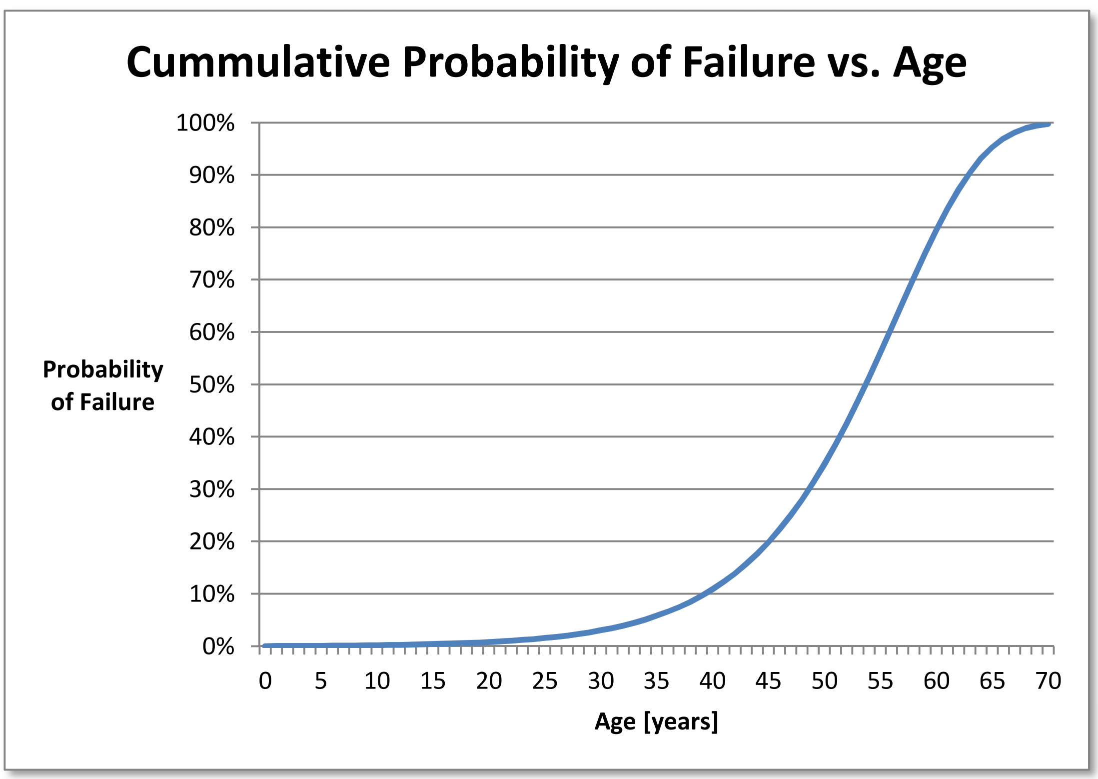


Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

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

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are $f_5 = 0.02$, $f_{10} = 0.05$, $f_{20} = 0.1$ failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore $8(f_1) + 19(f_6) + 45(f_{11}) + 45(f_{21})$.

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

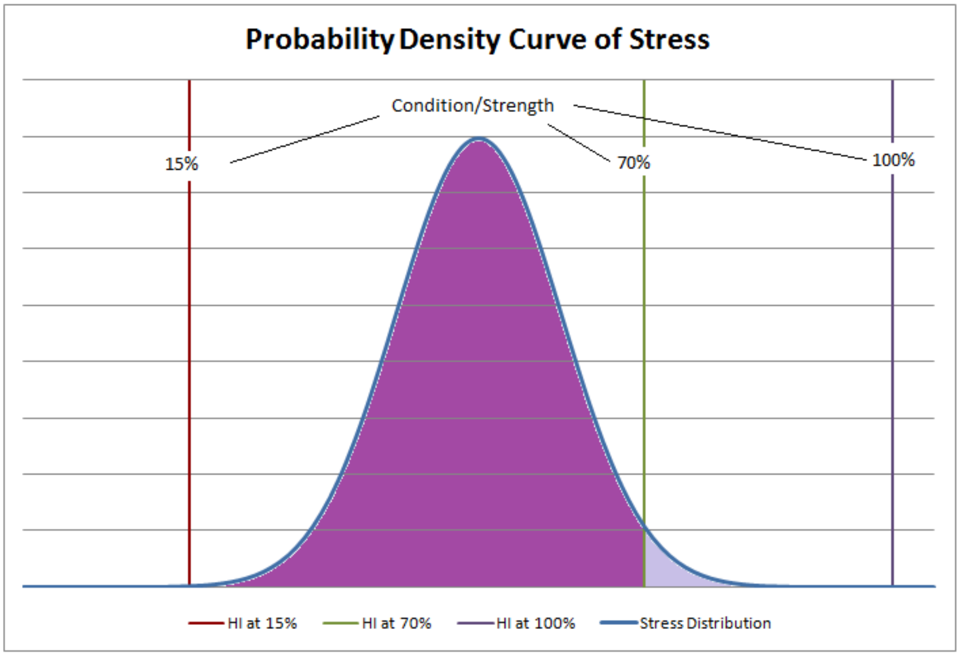


Figure II-3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two “points” on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

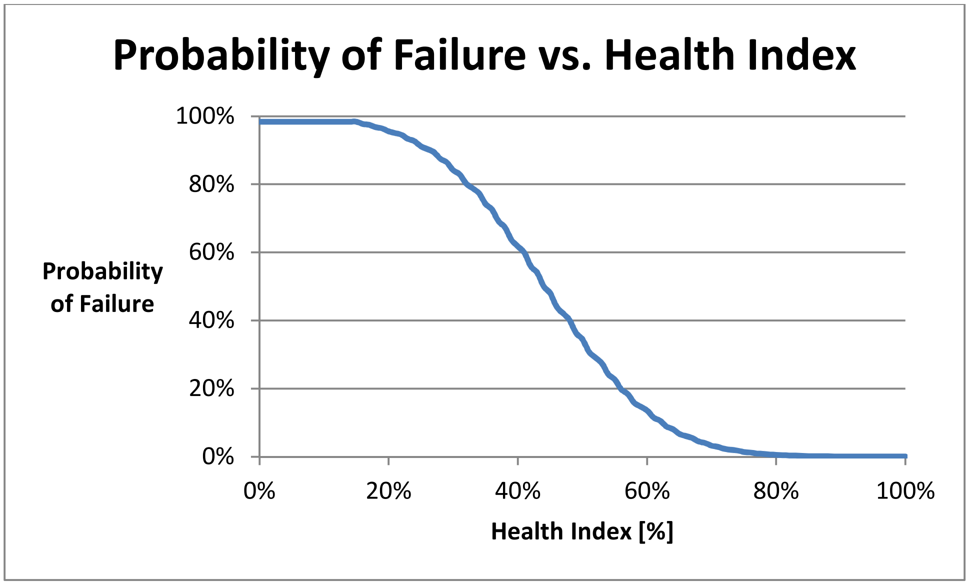


Figure II-4 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Power Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.25. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action.

III INTRODUCTION

The condition data used in this study were obtained from NPEI and included the following:

- Asset Properties (e.g. age, location information)
- Test Results (e.g. Oil Quality, DGA)
- Inspection Records

There are two components that assess the availability and quality of data used in this study: Data Gap and Data Availability Indicator (DAI).

III.1 Data Gap

The Health Index formulations developed and used in this study are based solely on NPEI's available data. There are additional parameters or tests that NPEI may not collect but nonetheless are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is *not* considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	✫ ✫ ✫
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	✫ ✫
Low	Helpful data; least indicative of asset deterioration	✫

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulations.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for “Tank Corrosion” on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III.2 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the “best” overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPm} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPm} = \frac{\sum_{n=1}^{\forall n} (\beta_n \times WCF_n)}{\sum_{n=1}^{\forall n} (WCF_n)}$$

Equation 7

DAI	Overall Data Availability Indicator for an asset with m Condition Parameters
DAI_{CPm}	Data Availability Indicator for Condition Parameter
WCP_m	Weight of Condition Parameter m
β_n	Data Availability Coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	**Name**		**n**	**Name**		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

$DAI_{CP1} = (1*1) / (1) = 1$
$DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545$
$DAI_{CP3} = (0*1) / (1) = 0$

$$DAI = (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3)$$
$$= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3)$$
$$= 35\%$$

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score.

It is important to note that while an asset may have a high DAI, having large data gaps will still result in a less reliable Health Index. For example, if the Health Index is based only on age and the entire asset population has age data, the average DAI for that asset category will be 100%. As age is not necessarily equal to condition, there may still be low confidence in the Health Index results for this asset category.

V RESULTS

V.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table V-1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), and age are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in Figure V-5. Note that the Health Index distribution percentages are based on the asset group's sample size.

It can be seen from the results power transformers, pole-top transformers, and wood poles have the highest percentages of units in poor and very poor condition.

Another noteworthy asset class is pad-mounted switchgear. Although only 2% of the samples were found to be in poor condition, 52% were found to be only in fair condition. This asset category also has the lowest average Health Index, 81%, of all asset categories.

V.2 Condition-Based Flagged for Action Plan

Table V-3 and Table V-4 show the 20 year Flagged for Action Plan and the Levelized Flagged for Action Plan respectively. The Flagged for Action Plan is based on the number of units expected to require attention in a given year. As it may not always be feasible to address assets as per this plan, a "levelized" plan is also given. Table V-2 shows year 1 of the Flagged for Action Plan as well as the asset action strategy for each asset group. Note that in deriving the plans, it is assumed that sample size-based Health Index distribution of a given asset category is applicable to the entire asset population (i.e. the Health Index distribution is extrapolated to the asset population and the Flagged for Action plan is based on the whole asset population).

It is important to note that the Flagged for Action Plan suggested in this study is based solely on asset Health Index, derived from available condition data and information. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units for flagged for action. While the Condition-Based Flagged for Action Plan can be used as a guide or input into NPEI's asset management activities, it is not expected that it be followed directly or as the final deciding factor in capital decisions. There are numerous other factors and considerations, such as obsolescence, system growth, corporate priorities, technological advancements, etc., that will influence NPEI's asset management decisions.

NPEI's most significant asset groups, in terms of number of units flagged for action in the near future, were pole-top transformers and wood poles. In year 1 it is estimated that 79 and 216 pole-top transformers and wood poles respectively will require attention.

Table V-1 Health Index Results Summary

Asset Category		Population	Sample Size		Average Age (NA = Not Available)	Average Health Index	Health Index Distribution				
			Number of Units	%			Very Poor (<= 30%)	Poor (>30 - 50%)	Fair (>50 - 70%)	Good (>70 - 85%)	Very Good (> 85%)
Power Transformers		19	19	100.0%	23	86%	0%	5%	0%	37%	58%
Large Pad-mounted Transformers		66	63	95.5%	17	93%	0%	0%	3%	13%	84%
Pole-top Transformers		6683	6648	99.5%	22	92%	< 1%	3%	3%	11%	82%
Wood Poles		24546	23610	96.2%	30	95%	< 1%	3%	2%	6%	88%
Standard Pad-mounted Transformers		2682	2682	100.0%	15	97%	0%	< 1%	< 1%	2%	98%
Pad-mounted Switchgear		74	60	81.1%	NA	81%	0%	2%	52%	5%	42%
Underground Cables (data in conductor-km)	**Main Feeder**	48	33	68.8%	10	98%	0%	0%	0%	8%	92%
	Distribution	427	282	66.0%	16	94%	< 1%	2%	3%	6%	89%

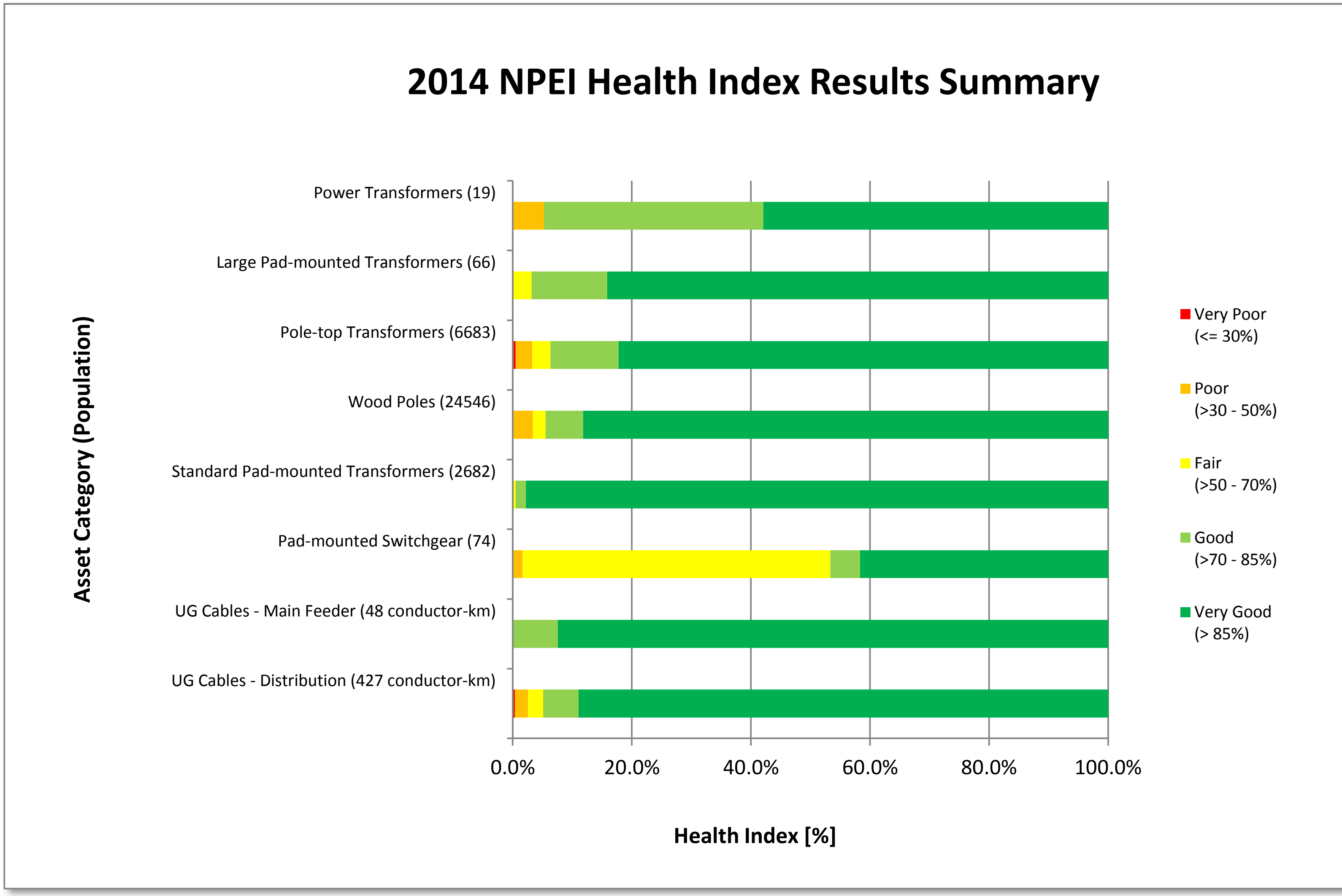


Figure V-5 Health Index Results Summary

Table V-2 Year 1 Condition Based Flagged for Action

Asset Category		Flagged for Action Plan for Year 1		Action Strategy
		Number of Units	Percentage of Population	
Power Transformers		0	0.0%	proactive
Large Pad-mounted Transformers		0	0.0%	proactive/reactive
Pole-top Transformers		79	1.2%	reactive
Wood Poles		216	0.9%	proactive/reactive
Standard Pad-mounted Transformers		1	0.0%	proactive/reactive
Pad-mounted Switchgear		0	0.0%	proactive
Underground Cables (data in conductor-km)	**Main Feeder**	0	0.0%	proactive
	Distribution	5	1.2%	proactive

Table V-3 Twenty Year Condition Based Flagged for Action Plan

20-Year Flagged for Action Plan (Number of Units per Year)																					
Asset Category		Years																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Power Transformers		0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Large Pad-mounted Transformers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0
Pole-top Transformers		79	64	53	49	43	41	35	35	33	36	38	39	40	40	43	45	45	48	49	60
Wood Poles		216	189	163	133	106	76	55	45	42	44	49	61	68	83	91	109	123	132	143	148
Standard Pad-mounted Transformers		1	1	0	0	1	0	0	0	0	2	1	3	3	3	4	6	6	10	10	10
Pad-mounted Switchgear		0	1	0	2	5	5	5	5	4	4	1	2	1	0	1	1	2	2	2	4
Underground Cables (data in conductor-km)	Main Feeder	0	0	0	1	0	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0
	Distribution	5	6	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5

Table V-4 Twenty Year Condition Based Levelized Flagged for Action Plan

20-Year Levelized Flagged for Action Plan (Number of Units per Year)																					
Asset Category		Years																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Power Transformers		0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Large Pad-mounted Transformers		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pole-top Transformers		79	64	53	49	41	42	42	42	42	42	42	42	41	42	42	42	42	42	42	42
Wood Poles		216	189	163	133	85	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
Standard Pad-mounted Transformers		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Pad-mounted Switchgear		3	2	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2	2
Underground Cables (data in conductor-km)	Main Feeder	0	0	0	1	0	0	0	0	1	0	0	0	1	0	0	0	1	0	0	0
	Distribution	5	6	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5

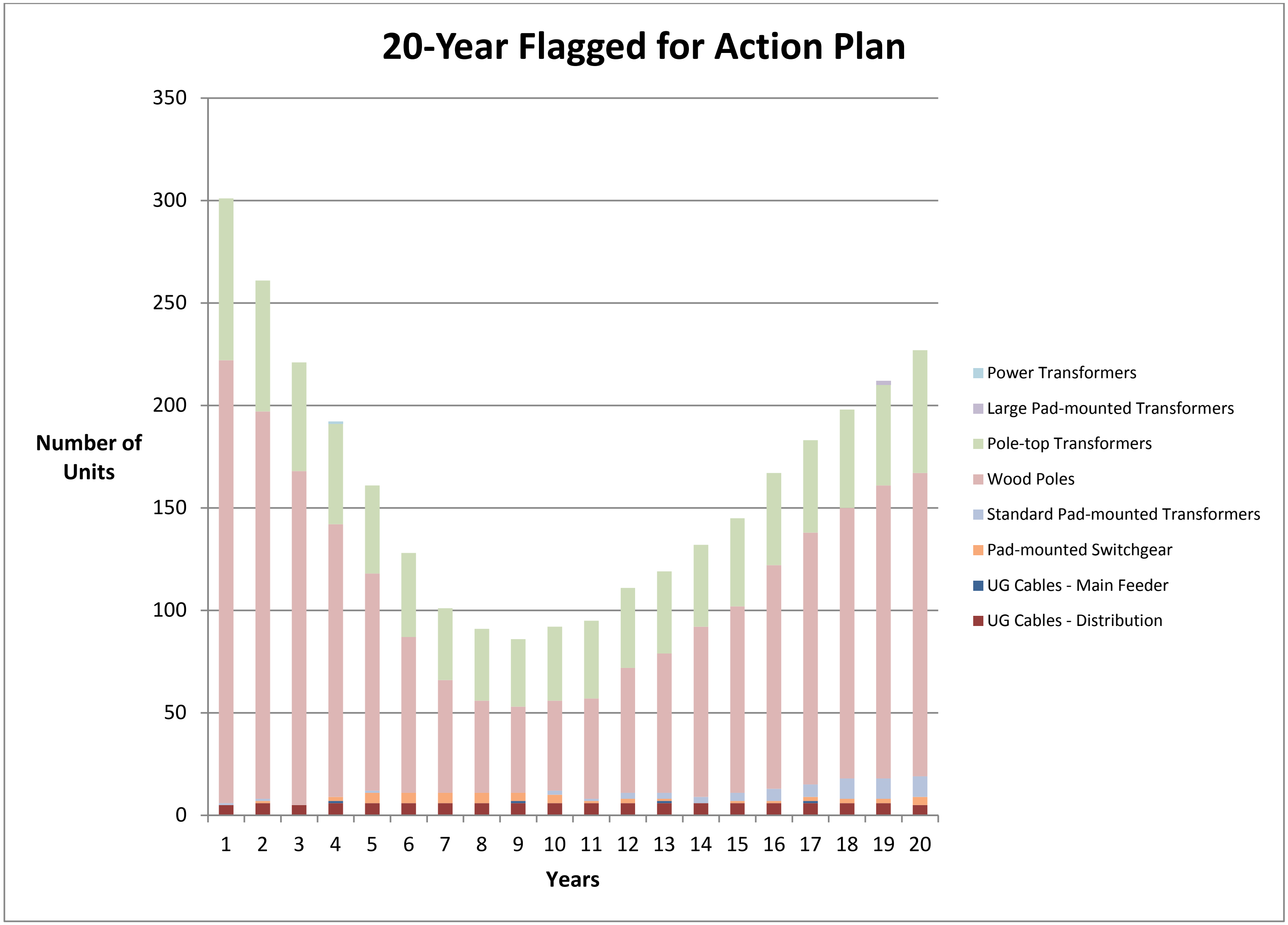


Figure V-6 Twenty Year Condition Based Flagged for Action Plan

Figure V-7 Twenty Year Condition Based Levelized Flagged for Action Plan

V.3 Data Assessment Results

The type of data available for power transformers include oil quality, dissolved gas analysis, and power dissipation factor tests, as well as age and inspections related to bushing, leaks, tank condition, and connections. For transformers in Niagara Falls maintenance reports were available (e.g. power dissipation tests, detailed inspections). Such data was not available for Penwest units.

The type of data available for large power transformers include oil quality and dissolved gas analysis, as well as age and limited inspection records related to tank condition and leaks. More detailed inspections were not available for this asset group.

Age and number of customers were the only available data for pole-top transformers. Data gaps include information regarding transformer physical condition (e.g. condition of enclosure, leaks, bushing, elbows/inserts, etc.), typically gathered from visual inspections.

NPEI's pole inspection program provides information on pole age, type, and physical condition (e.g. damage, holes, rot, etc.). Pole accessories (e.g. cross arms, guy wires, grounding, etc.) are also inspected.

Standard pad-mounted transformers are inspected on a 5 year cycle. Condition data gathered from inspections include status of transformer enclosure, base, grounding, insulation, as well as infrared and ultrasonic scans. Age and number of customers were also available for pad-mounted transformers.

Pad-mounted switchgear are subject to inspections every 5 years. Inspection data includes condition of enclosure, base, insulation, grounding, and overall switchgear condition. Infrared and ultrasonic tests are also available for this asset group.

Age was the only available information for underground cables. While this asset group has regular visual inspections and infrared and ultrasonic scans, such data has not yet been incorporated into the Health Index. Additional data gaps include test results (e.g. insulation resistance, AC withstand, partial discharge, dielectric loss, time domain reflectometry) and failure statistics.

V.4 2011 to 2014 Audit

In 2011 a full Asset Condition Assessment (ACA) for key distribution assets was conducted for NPEI by Kinectrics. Between 2011 and 2014, NPEI took steps to adopt the recommendations prescribed by the 2011 ACA and to improve the quality of its condition data. As described in this report, a subsequent ACA was conducted by Kinectrics for NPEI's assets as of 2014. In addition, Kinectrics assessed the changes with respect to ACA between the 2011 and 2014. This section of the report describes the findings.

Asset Categories

Health Index (HI) formulation and results from 2011 and 2014 were compared for the following Asset Categories and Sub-Categories:

- Power Transformers
- Large Pad-mounted Transformers
- Pole-top Transformers
- Wood Poles
- Standard Pad-mounted Transformers
- Pad-mounted Switchgear

Underground Cables, which are included in the 2014 assessment were not assessed in 2011 and are therefore not included in the audit.

Audit Results

For each Asset Category, the following aspects were compared between 2011 and 2014:

1. Health Index Formulation
2. Population and Sample Size
3. Health Index Distribution

Changes in Health Index Formulation

Since 2011, additional condition data has become available for Power Transformers. As such, the 2014 Health Index Formula incorporates power dissipation factor and more detailed inspection records.

Another change between 2011 and 2014 are revised failure curves for some asset categories. NPEI examined the failure curves assumed in the 2011 ACA and made adjustments so that the 2014 failure curves for some assets are less conservative and more reflective of NPEI experience.

For example, in 2011 the failure curve for standard pad-mounted transformers was modeled such that for the ages of 25 and 45 years, the cumulative probabilities of failure were 10% and 90% respectively. Experience has led NPEI to the conclusion that these assets would typically live longer than 25 years. As such, 2014 model was assumed to be less conservative and the failure curve was modeled such that for the ages of 35 and 45 the cumulative probabilities of failure were 20% and 90% respectively.

Assets with revised failure curves are: Pole-top transformers, wood poles, standard pad-mounted transformers, pad-mounted switchgear. Note that in the pad-mounted switchgear category, separate curves were developed for air insulated and gas insulated types.

Another noteworthy change between 2011 and 20141 is the change in the “age” criteria. In 2011 the scoring system, or condition parameter factor (CPF), for the age condition was discrete. For example, a certain category may have had the following age criteria:

Score (CPF)	Age
4	0 – 19 years
3	20-39 years
2	40 – 59 years
1	60 – 69 years
0	50+ years

The 2014 criteria are continuous and are based on the probability of failure (POF) of an asset. The continuous POF equation is explained in Section II.2.1. The criteria for individual asset classes are determined from typical asset lives and are explained in each asset subsection.

Changes in Population and Sample Size

Table V-5 summarizes the Change in Population and in Sample Size between 2011 and 2014. Graphical representations of the data are given on Figure V-8 and Figure V-9.

Changes in Population

The population of power transformers decreased by 4, or 17%, between 2011 and 2014. In 2011 the following numbers of transformers were included: three for Smithville DS, two for Green Lane DS, two for Allendale, and two for Virginia. In 2014, only one transformer was included for each station. Additionally, one transformer was added for Pellham DS in 2014.

The 10 unit, or 18% increase, of large pad-mounted transformers between 2011 and 2014 is a result of data validation and transformer classification.

The population of pole-top transformers remained fairly steady, whereas the population of wood poles increased by 10%. The increase in wood pole population can be attributed to NPEI's GIS data validation. Additionally NPEI is now inspecting poles that have NPEI equipment.

The population of standard pad-mounted transformers increased by 274 units (11%). The population of pad-mounted switchgear, however, decreased by 15 units (17%).

Changes in Sample Size

Ideally, condition data should be available for every asset within a population. Failing that, the larger the sample size, or subset of assets with sufficient condition information for Health Indexing, the more confidence there is in extrapolating the ACA results over an entire asset population.

The sample sizes for power transformers and pole-top transformers were close to 100% in 2011 and remained steady in 2014.

In 2011 large pad-mounted transformers had a sample size of 91%. A 4% improvement was seen in 2014 where the sample size rose to 95%.

The remaining asset categories had very significant increases in sample size. In 2014 data was available for 96% of wood poles. This represents a 69% increase in sample size since 2011.

Similarly, the sample size of standard pad-mounted transformers increased by 70% (to 100%) in 2014. Pad-mounted switchgear also had a significant increase in sample size. Approximately 81% of the population now has condition data, a 38% increase since 2011.

Table V-5 Summary Change in Population and Sample Size

Asset		Population				Sample Size		
		Population Count 2011	Population Count 2014	Population Change from 2011 by Counts	Population Change from 2011 by %	% Sample Size 2011	% Sample Size 2014	Sample Size Change by %
1	Power Transformers	23	19	-4	-17%	100%	100%	0%
2	Large Pad-mounted Transformers	56	66	10	18%	91%	95%	4%
3	Pole-top Transformers	6835	6683	-152	-2%	98%	99%	1%
4	Wood Poles	22247	24546	2299	10%	27%	96%	69%
5	Standard Pad-mounted Transformers	2408	2682	274	11%	30%	100%	70%
6	Pad-mounted Switchgear	89	74	-15	-17%	43%	81%	38%

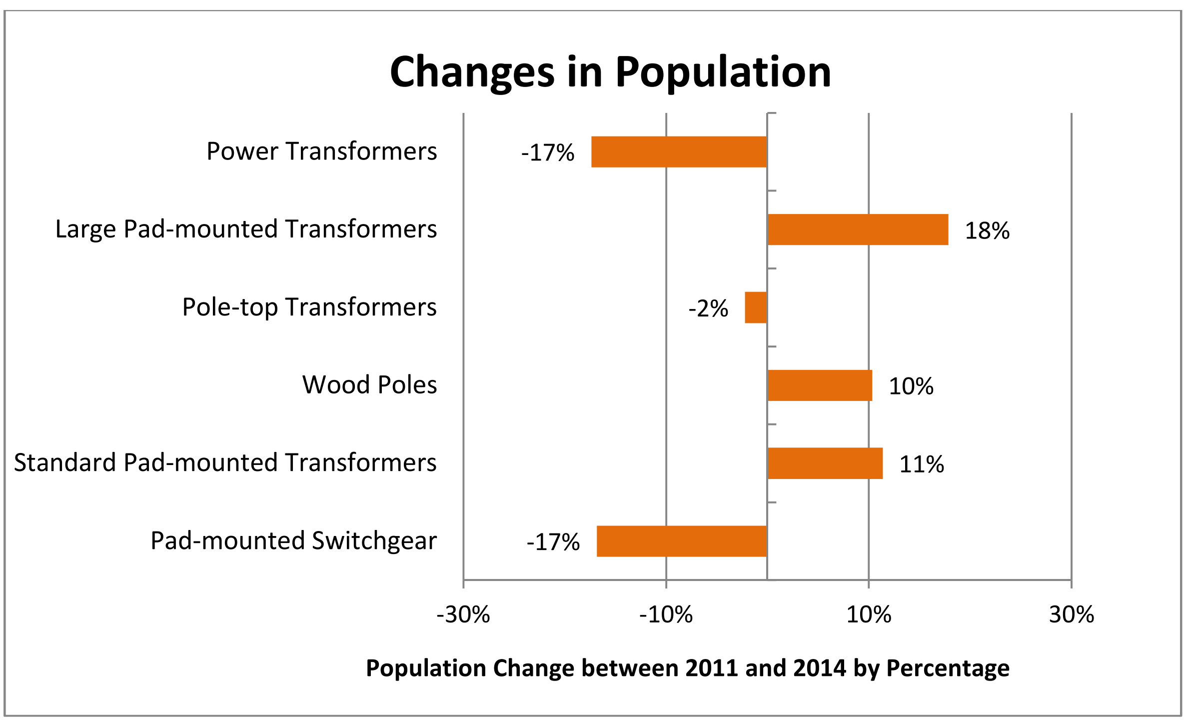
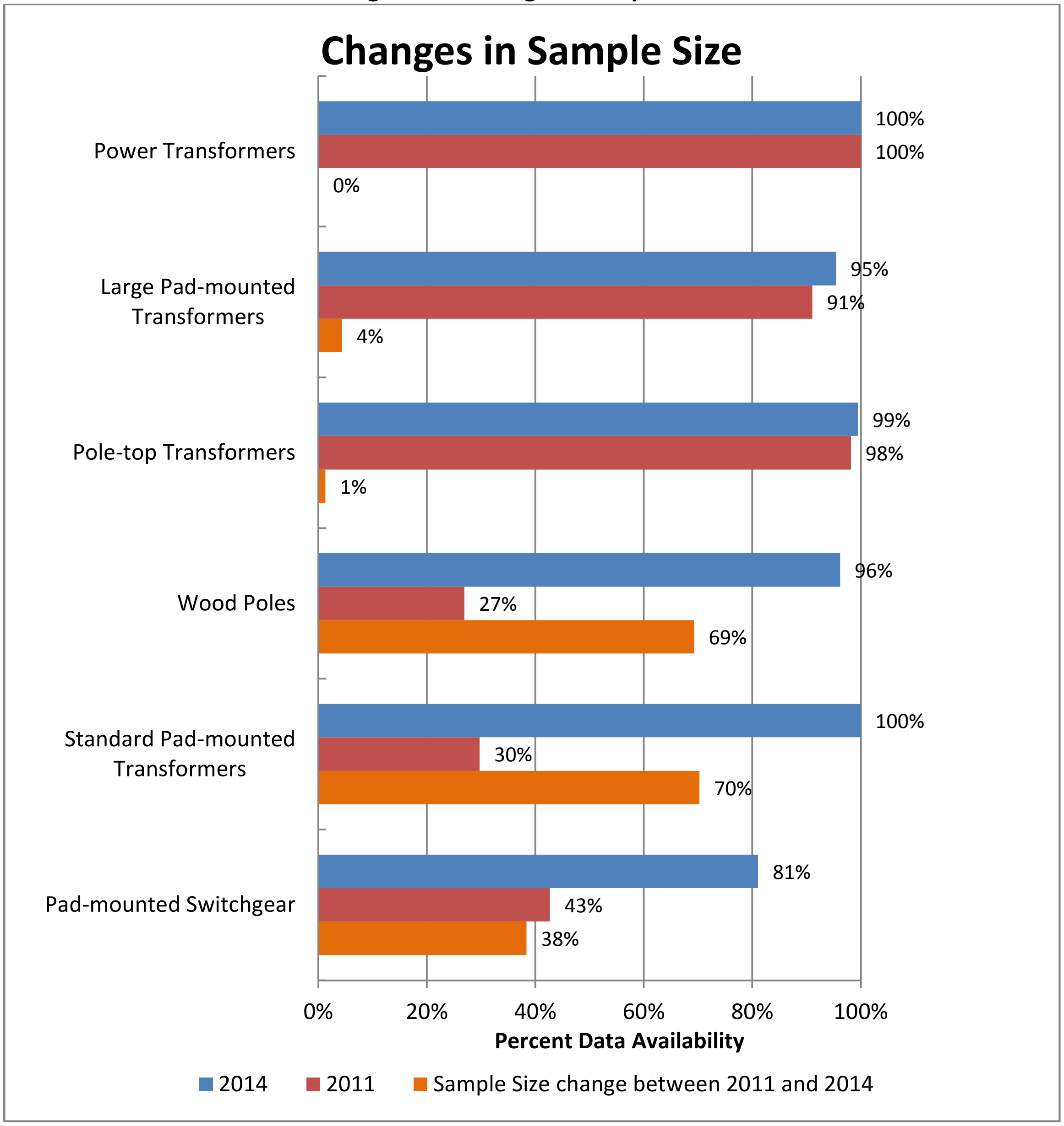


Figure V-8 Change in Population

Figure V-9 Change in Sample Size



Changes in Health Index Distribution

The changes in Health Index distribution between 2011 and 2014 are summarized in Table V-6 and graphically shown in Figure V-10.

The overall trend with respect to Health Index distribution was assessed. Assets that showed an increasing percentage of “good” and/or “very good” or a decrease of “very poor”, “poor”, and/or “fair” were classified as having overall improved health distributions. Conversely, asset classes with a decreasing percentage of “good” and/or “very good” or an increasing percentage of “very poor”, “poor”, and/or “fair” were classified as having an overall decline in health.

Power Transformers: The trend shows a general improvement in overall condition. Installations of new transformers in Smithville DS and Green Lane DS have contributed to this trend.

Large Pad-mounted Transformers: The trend shows a general improvement in overall condition. Many assets that were classified as “good” are now classified as “very good”, but this is likely a result of Health Index formula refinement (e.g. improved age criteria).

Pole-top Transformers: It appears that there is an overall improvement in condition, however it is likely that this change is a result of Health Index formula refinement (e.g. improved age criteria).

Wood Poles: Wood poles showed very significant improvement in overall health. This change may be due to the significant increase in sample size (i.e. improved knowledge about the asset population).

Pad-mounted Transformers: Wood poles showed improvement in overall health. This change may be attributed to the significant increase in sample size (i.e. improved knowledge about the asset population).

Pad-mounted Switchgear: In 2011 a large number of the switchgear population as classified as poor to very poor. This change may be partially due to the significant increase in sample size and improved knowledge about the population. Another contributing factor is the de-rating multiplier of 30% that was applied to air insulated switchgear near major roadways. In 2014 the Health Index formula was refined and the multiplier was increased to 70%. Further, the service life of the air insulated switchgear was better modelled by assuming different life curves for air and gas insulated switchgear.

Table V-6 Summary Change in Health Index Distribution

	Asset	Year	Very Poor		Poor		Fair		Good		Very Good	
			% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change
1	Power Transformers	2011	0.0%	0%	17.4%	-12%	26.1%	-26%	21.7%	15%	34.8%	23%
		2014	0.0%		5.3%		0.0%		36.8%		57.9%	
2	Large Pad-mounted Transformers	2011	0.0%	0%	2.0%	-2%	5.9%	-3%	27.5%	-15%	64.7%	19%
		2014	0.0%		0.0%		3.2%		12.7%		84.1%	
3	Pole-top Transformers	2011	0.6%	0%	4.2%	-1%	11.3%	-8%	17.3%	-6%	66.7%	16%
		2014	0.5%		2.8%		3.0%		11.4%		82.2%	
4	Wood Poles	2011	0.2%	0%	4.9%	-2%	5.7%	-4%	28.2%	-22%	61.1%	27%
		2014	0.1%		3.3%		2.2%		6.3%		88.1%	
5	Standard Pad-mounted Transformers	2011	5.2%	-5%	1.3%	-1%	1.1%	-1%	3.9%	-2%	88.5%	9%
		2014	0.0%		0.1%		0.4%		1.7%		97.8%	
6	Pad-mounted Switchgear	2011	7.9%	-8%	34.2%	-33%	2.6%	49%	18.4%	-13%	36.8%	5%
		2014	0.0%		1.7%		51.7%		5.0%		41.7%	

Figure V-10 Change in Health Index Distribution

VI CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for NPEI's key distribution assets, namely power transformers, large pad-mounted transformers, pole-top transformers, wood poles, standard pad-mounted transformers, pad-mounted switchgear, main feeder and distribution underground cables. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

2. Power transformers, pole-top transformers, and wood poles have the highest percentages of units in poor and very poor condition. More than 5%, 3%, and 3% of power transformers, pole-top transformers, and wood poles respectively are classified as poor to very poor.

3. Also of significance is that although only 2% of the pad-mounted switchgear samples were in poor condition, 52% were found to be only in fair condition. This asset category also has the lowest average Health Index, 81%, of all asset categories.

4. NPEI's most significant asset groups, in terms of number of units flagged for action in the near future, were pole-top transformers and wood poles. In year 1 it is estimated that 79 and 216 pole-top transformers and wood poles respectively will require attention.

5. Power transformers located in Niagara Falls had available detailed substation reports that included power dissipation tests and more detailed inspections. It is recommended that such data be collected for Penwest units. It is also recommended that information related to transformer cooling system and loading data incorporated into the Health Indexing process.

6. Although large power transformers are regularly inspected and subject to infrared and ultrasonic tests, such data has not yet been incorporated into the Health Index formula. Additionally, it is recommended that loading data also be included in the Health Indexing process.

7. As only age and number of customers are available for pole-top transformers, it is recommended that information gathered from regular visual inspections be incorporated into the Health Indexing process.

8. Only age was available for underground cables. It is recommended that information gathered from visual inspections and ultrasonic and infrared scans be incorporated into the Health Index. Test data provides the best indicator of condition. If NPEI chooses to engage in cable testing, it is recommended that such data be incorporated into the Health Index. It is also recommended that NPEI collect age data for segments where age is not available, thus increasing this asset category's sample size.

9. An audit assessing the ACA changes between 2011 and 2014 was conducted. The following aspects were compared: Health Index Formulation, Population and Sample Size, Health Index Distribution. A total of six asset groups were included. Underground Cables, which were first assessed in 2014 were not subject to the audit.

10. Between 2011 and 2014, the Health Index formulations for some asset categories were refined to include new data, more representative failure curves, and/or refined condition criteria.

11. With the exception of pole-top transformers, there were changes in the population of all asset groups. Reasons for such changes include decommissioning or installation of assets, as well as cleansing and validation of NPEI data.

12. NPEI has made significant strides in terms of improving the sample sizes. The sample sizes of 5 of the 6 asset groups included in the audit were 95% or higher. Between 2011 and 2014 the sample sizes for wood poles, standard pad-mounted transformers, and pad-mounted switchgear improved by 69%, 70%, and 38% respectively.

13. It is recommended that NPEI continue efforts to increase the sample size for each asset category.

14. There was a significant improvement in the overall health of power transformers. This is likely a result of new transformer installations in Smithville DS and Green Lane DS.

15. There is an apparent significant improvement in the overall condition of pad-mounted switchgear. Contributing factors may be the adjustment of the de-rating multiplier used in the Health Index formula and the significantly improved sample size, allowing for improved knowledge of the population.

16. It is important to note that the Flagged for Action plan presented in this study is based solely on asset condition as determined by available data. There are numerous other considerations that may influence NPEI's asset management plan. Among these are obsolescence, system growth, corporate priorities, technological advancements, etc.

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APPENDIX A: RESULTS AND FINDINGS FOR EACH ASSET CATEGORY

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1 Power Transformers

1.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Power Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Parameters and Weights

Condition Parameter			Sub-Condition Parameter			
m	CP Name	Weight of Condition Parameter [WCP]	n	CPF Name	Weight of Condition Parameter Factor [WCPF]	Lookup Table
1	Insulation	4	1	Oil Quality	4	Table 1-2
			2	Oil DGA	5	Table 1-3
			3	Winding Power Dissipation Factor	5	Table 1-4
			4	Bushing	1	Table 1-5
2	Sealing & Connection	1	1	Tank Condition	1	Table 1-5
			2	Connection	1	Table 1-5
			3	Leak	1	Table 1-5
3	Service Record	2	1	Age	1	Figure 1-1

1.1.2 Condition Parameter Criteria

Oil Quality

Table 1-2 Power Transformers Oil Quality Test Criteria

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

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

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	**Weight**
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	
Dielectric Strength (D1816 - 2 mm gap) [kV]	V ≤ 69	> 40	35-40	30-35	< 30	4
	69 < V < 230	> 47	42-47	35-42	< 35	
	V ≥ 230	> 50	50-45	40-45	< 40	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974) [mg KOH/g]	V ≤ 69	< 0.05	0.05-0.01	0.1-0.2	> 0.2	4
	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	
	V ≥ 230	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5
Dissipation Factor (D924 - 100^{0}C)	All	< 5%	5%-10%	10%-20%	> 20%	

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

For example if all data is available, overall Factor = $\dfrac{\sum Score_i \times Weight_i}{12}$

<u>Oil DGA</u>

Table 1-3 Power Transformers Oil DGA Criteria

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*NOTE: In the case of a score other than 4, 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 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

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

2.5 MVA to Under 10 MVA

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=70	<=100	<=200	<=400	<=1000	>1000	**4**
CH4(Methane)	<=70	<=120	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=75	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=100	>100	**5**
CO	<=750	<=1000	<=1300	<=1500	<=1700	>2000	**4***
CO2	<=7500	<=8500	<=9000	<=12000	<=15000	>15000	**4***
CO2/CO	3 - <10	<12	<15 Or <3	<18	<20	>20	**4***

*If CO $\geq$ 500 ppm and CO2 $\geq$ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4)
If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)

10 MVA and Higher

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=40	<=100	<=300	<=500	<=1000	>1000	**4**
CH4(Methane)	<=80	<=150	<=200	<=500	<=700	>700	**3**
C2H6(Ethane)	<=70	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=500	<=600	<=1000	<=1500	>1500	**4***
CO2	<=3000	<=4500	<=5700	<=7500	<=10000	>12000	**4***
CO2/CO	3 - <8	< 10	<13 Or <3	<14	<15	>15	**4***

*If CO $\geq$ 500 ppm and CO2 $\geq$ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4)
If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)

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

Winding Power Dissipation Factor

Table 1-4 Power Transformers Power Dissipation Factor Test Criteria

CPF	Description
4	%PF < 0.5%
3	0.5% < %PF < 0.7%
2	0.7% < %PF < 1%
1	1.0% < %PF < 2.0%
0	%PF > 2.0%

Inspections

Table 1-5 Power Transformers Inspection Score

CPF	Description
0	Poor
2	Fair
4	Good

Age

Assume that the failure rate for Power Transformers exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for this asset are 20% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

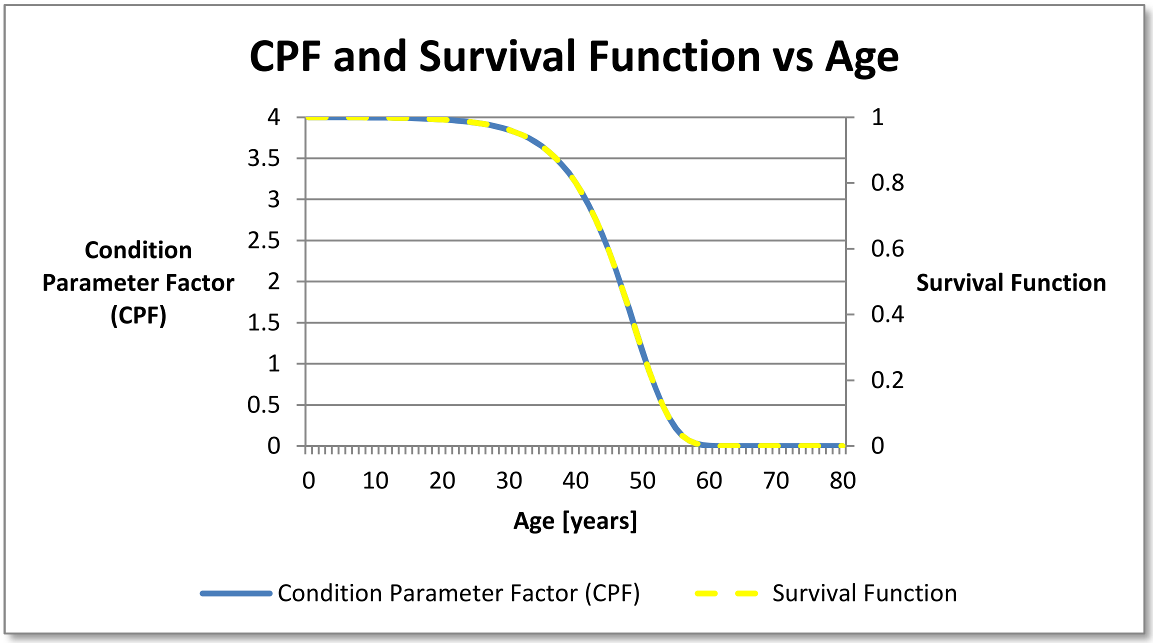

Figure 1-1 Power Transformers Age Condition Criteria

1.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 100% of the population. The average age was found to be 23 years.

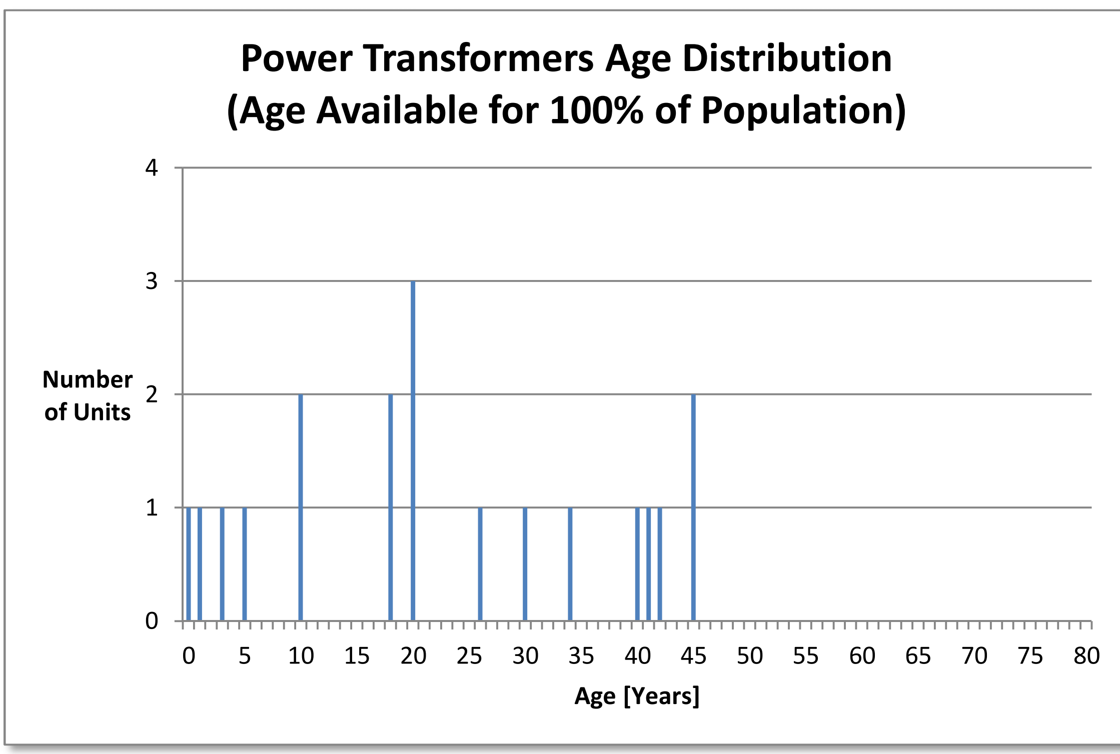

Figure 1-2 Power Transformers Age Distribution

1.3 Health Index Results

At the time of assessment, there were 19 in service Power Transformers at NPEI. Of these, 19 units had sufficient data for assessment.

The average Health Index for this asset group is 86%. It was found 5% of the samples were in poor condition.

The Health Index Distribution is shown in Figure 1-3.

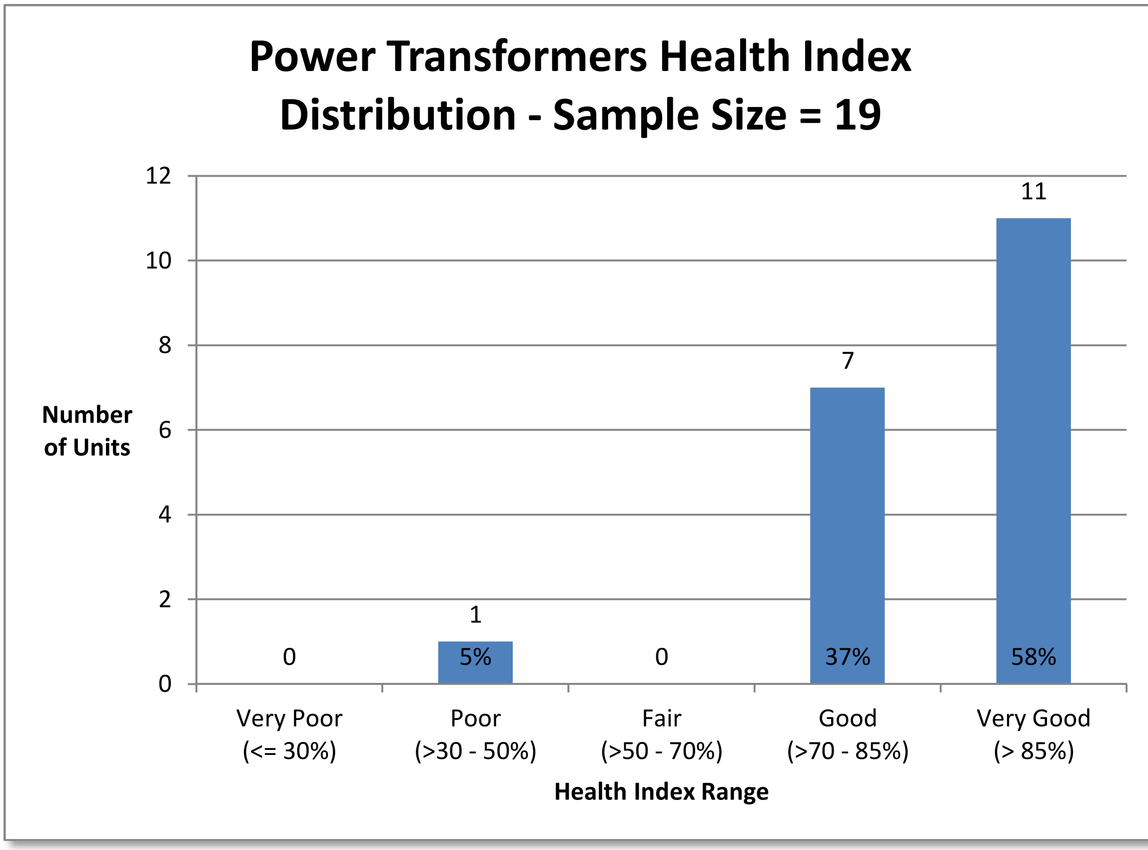

Figure 1-3 Power Transformers Health Index Distribution

1.4 Condition-Based Flagged for Action Plan

It is assumed that Power Transformers are proactively addressed. Based on current condition (Health Index) of Power Transformers and that the assumption that the rate of aging is constant (i.e. units do not continue to degrade faster than what would be typical), the Flagged for Action Plan is as follows. Because only one unit is flagged, levelization is not required.

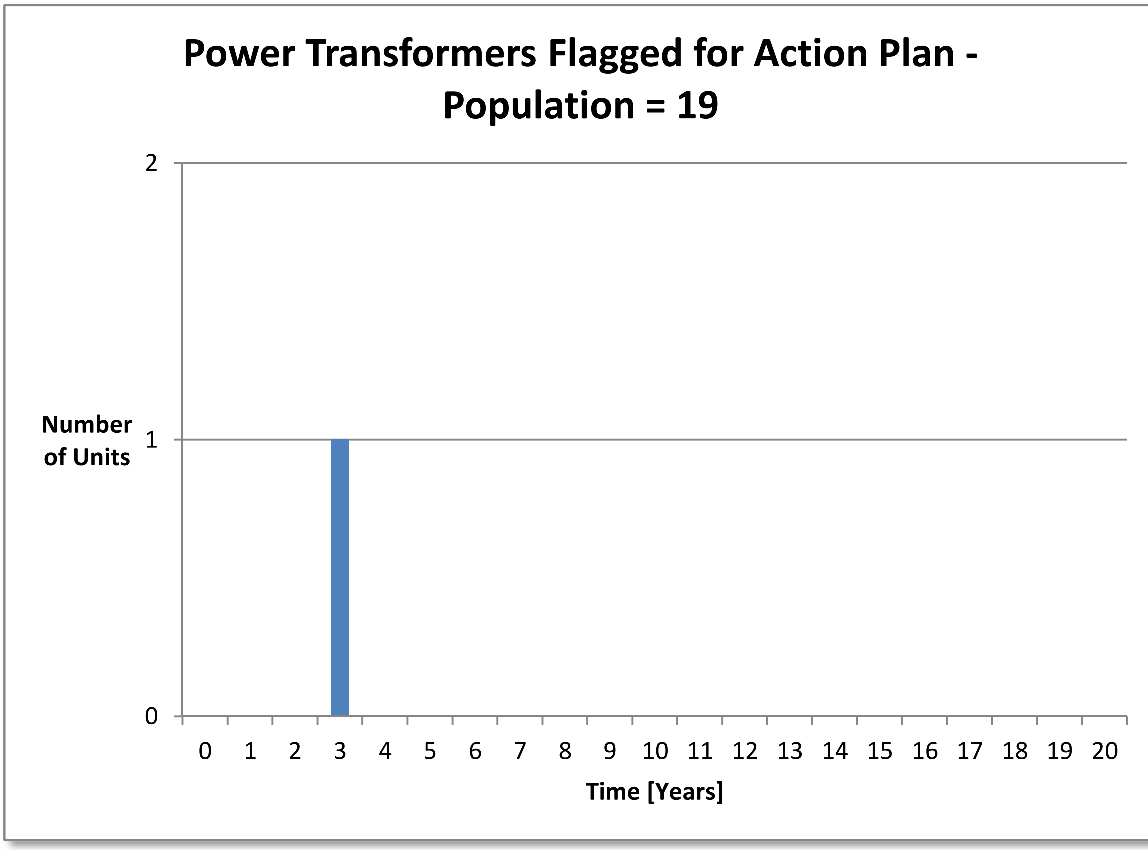

Figure 1-4 Power Transformers Condition-Based Flagged for Action Plan

The detailed results, from lowest to highest Health Index are shown below:

Table 1-6 Results for Each Power Transformers Unit

Transformer	TC	Station Name	Subset	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
SD-1850	54	CAMPDEN D.S.	PENWEST	42	72%	**39.93%**	Poor	3
800100	21	O'NEIL A-148	NIAGARA FALLS	45	100%	**70.27%**	Good	>20
SD001	76	STATION ST. D.S.	PENWEST	45	72%	**74.08%**	Good	>20
800095	31	MARGARET A-127	NIAGARA FALLS	41	100%	**74.35%**	Good	>20
800077	45	ONTARIO A-115	NIAGARA FALLS	26	100%	**76.59%**	Good	>20
800073	39	ARMOURY A-113	NIAGARA FALLS	40	97%	**77.66%**	Good	>20
800082	35	ALLENDALE A-175	NIAGARA FALLS	34	100%	**78.79%**	Good	>20
800388	30	PEW A-135	NIAGARA FALLS	18	72%	**83.59%**	Good	>20
800053	25	SWAYZE A-145	NIAGARA FALLS	20	100%	**87.90%**	Very Good	>20
800295	38	LEWIS A-119	NIAGARA FALLS	30	100%	**87.94%**	Very Good	>20
800389	32	DRUMMOND A-122	NIAGARA FALLS	18	100%	**87.96%**	Very Good	>20
800052	44	PARK A-33	NIAGARA FALLS	20	100%	**92.66%**	Very Good	>20
800054	23	VIRGINIA A-144	NIAGARA FALLS	20	81%	**97.42%**	Very Good	>20
800651		PELHAM D.S.	PENWEST	5	29%	**99.97%**	Very Good	>20
2515T1	29	KALAR TS	NIAGARA FALLS	10	72%	**99.97%**	Very Good	>20
2515T2	28	KALAR TS	NIAGARA FALLS	10	72%	**99.97%**	Very Good	>20
SD-1844	78	SMITHVILLE DS - NF1844	PENWEST	3	72%	**100.00%**	Very Good	>20
SD1856	144	GREENLANE DS	PENWEST	1	68%	**100.00%**	Very Good	>20
SD1836	73	JORDAN D.S. - NF 1836	PENWEST	0	29%	**100.00%**	Very Good	>20

1.5 Data Analysis

The type of data available for power transformers include oil quality, dissolved gas analysis, and power dissipation factor tests, as well as age and inspections related to bushing, leaks, tank condition, and connections. For transformers in Niagara Falls maintenance reports were available (e.g. power dissipation tests, detailed inspections). Such data was not available for Penwest units.

1.5.1 Data Gaps

All of the critical data, namely oil quality and DGA, winding power dissipation factor and inspections are available and included in the Health Index formula.

A few parameters that can be included in the Health Index formula follow.

Table 1-7 Power Transformers Data Gaps

<table>
<tr><th>Data Gap
(Sub-Condition Parameter)</th><th>Parent Condition Parameter</th><th>Priority</th><th>Object or Component Addressed</th><th>Description</th><th>Source of Data</th></tr>
<tr><td rowspan="7">Cooling</td><td rowspan="7">Cooling</td><td rowspan="7">☆☆☆</td><td rowspan="2">Cooling oil</td><td>Abnormal oil flow</td><td rowspan="7">Visual Inspection / On-site Reading / IR Scans</td></tr>
<tr><td>Abnormal oil pump motor</td></tr>
<tr><td>Radiator</td><td>Plugged radiator</td></tr>
<tr><td>Valves</td><td>Broken valves</td></tr>
<tr><td>Transformer tank</td><td>High top oil temperature</td></tr>
<tr><td rowspan="2">Winding</td><td rowspan="2">High winding temperature</td></tr>
<tr></tr>
<tr><td>Loading</td><td>Service Record</td><td>☆☆</td><td>Transformer Loading</td><td>Loading history (e.g. monthly 15 minute peaks)</td><td>Operations records.</td></tr>
</table>

1.5.2 Data Availability Distribution

Nearly all units had age, oil quality, and DGA tests, and some inspection records available. Transformers in Niagara had more detailed substation maintenance records that include power dissipation factor tests.

The average DAI for Power Transformers, as measured against the existing Health Index formula/data set, is 81%.

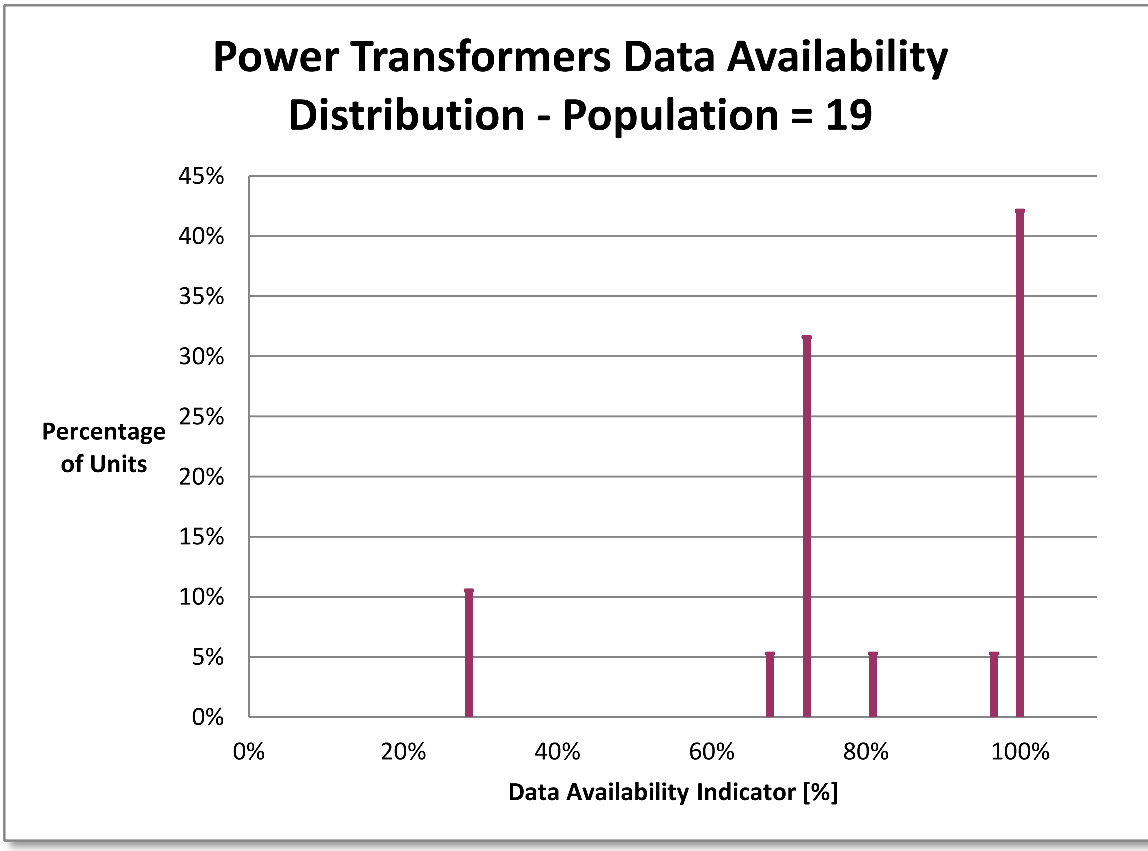

Figure 1-5 Power Transformers Data Availability Distribution

2 Large Pad-Mount Transformers

2.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Large Pad-Mount Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

2.1.1 Condition and Sub-Condition Parameters

Table 2-1 Condition Parameters and Weights

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Insulation	4	1	Oil Quality	4	Table 2-2
			2	Oil DGA	5	Table 2-3
2	Sealing & Connection	1	1	Tank Condition	1	Table 2-4
			2	Leak	1	Table 2-4
3	Service Record	2	1	Age	1	Figure 2-1

2.1.2 Condition Parameter Criteria

Oil Quality

Table 2-2 Large Pad-Mount Transformers Oil Quality Test Criteria

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

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

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	
Dielectric Strength (D1816 - 2 mm gap) [kV]	V ≤ 69	> 40	35-40	30-35	< 30	4
	69 < V < 230	> 47	42-47	35-42	< 35	
	V ≥ 230	> 50	50-45	40-45	< 40	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974) [mg KOH/g]	V ≤ 69	< 0.05	0.05-0.01	0.1-0.2	> 0.2	4
	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	
	V ≥ 230	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5
Dissipation Factor (D924 - 100^{0}C)	All	< 5%	5%-10%	10%-20%	> 20%	

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

For example if all data is available, overall Factor = $\frac{\sum Score_i \times Weight_i}{12}$

Oil DGA

Table 2-3 Large Pad-Mount Transformers Oil DGA Criteria

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*NOTE: In the case of a score other than 4, 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 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

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

2.5 MVA to Under 10 MVA

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=70	<=100	<=200	<=400	<=1000	>1000	**4**
CH4(Methane)	<=70	<=120	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=75	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=100	>100	**5**
CO	<=750	<=1000	<=1300	<=1500	<=1700	>2000	**4***
CO2	<=7500	<=8500	<=9000	<=12000	<=15000	>15000	**4***
CO2/CO	3 - <10	<12	<15 Or <3	<18	<20	>20	**4***

*If CO $\geq$ 500 ppm and CO2 $\geq$ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4)
If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)

10 MVA and Higher

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=40	<=100	<=300	<=500	<=1000	>1000	**4**
CH4(Methane)	<=80	<=150	<=200	<=500	<=700	>700	**3**
C2H6(Ethane)	<=70	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=500	<=600	<=1000	<=1500	>1500	**4***
CO2	<=3000	<=4500	<=5700	<=7500	<=10000	>12000	**4***
CO2/CO	3 - <8	< 10	<13 Or <3	<14	<15	>15	**4***

*If CO $\geq$ 500 ppm and CO2 $\geq$ 5000 ppm, use CO2/CO ratio (e.g. CO and CO2 weights = 0, CO2/CO weight = 4)
If CO < 500 ppm and CO2 < 5000 ppm, use CO2 and CO limits (e.g. CO and CO2 weights = 4, CO2/CO weight = 0)

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

Inspections

Table 2-4 Large Pad-Mount Transformers Inspection Score

CPF	Description
0	Poor
2	Fair
4	Good

Age

Assume that the failure rate for Large Pad-Mount Transformers exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for this asset are 20% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

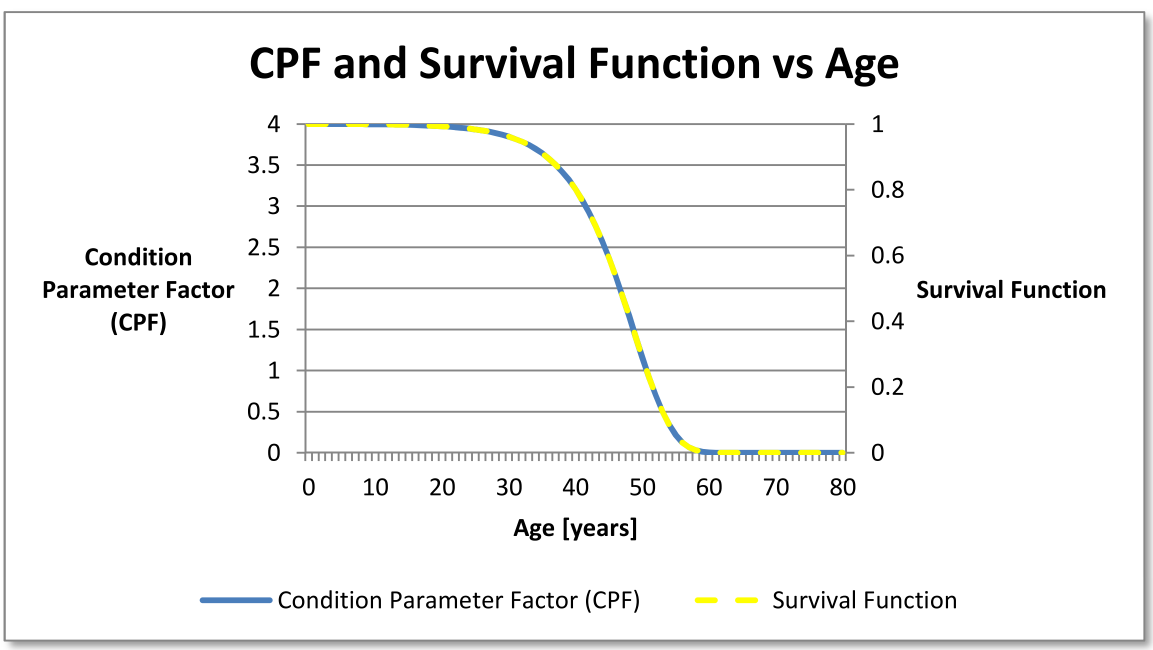

Figure 2-1 Large Pad-Mount Transformers Age Condition Criteria

2.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 91% of the population. The average age was found to be 17 years.

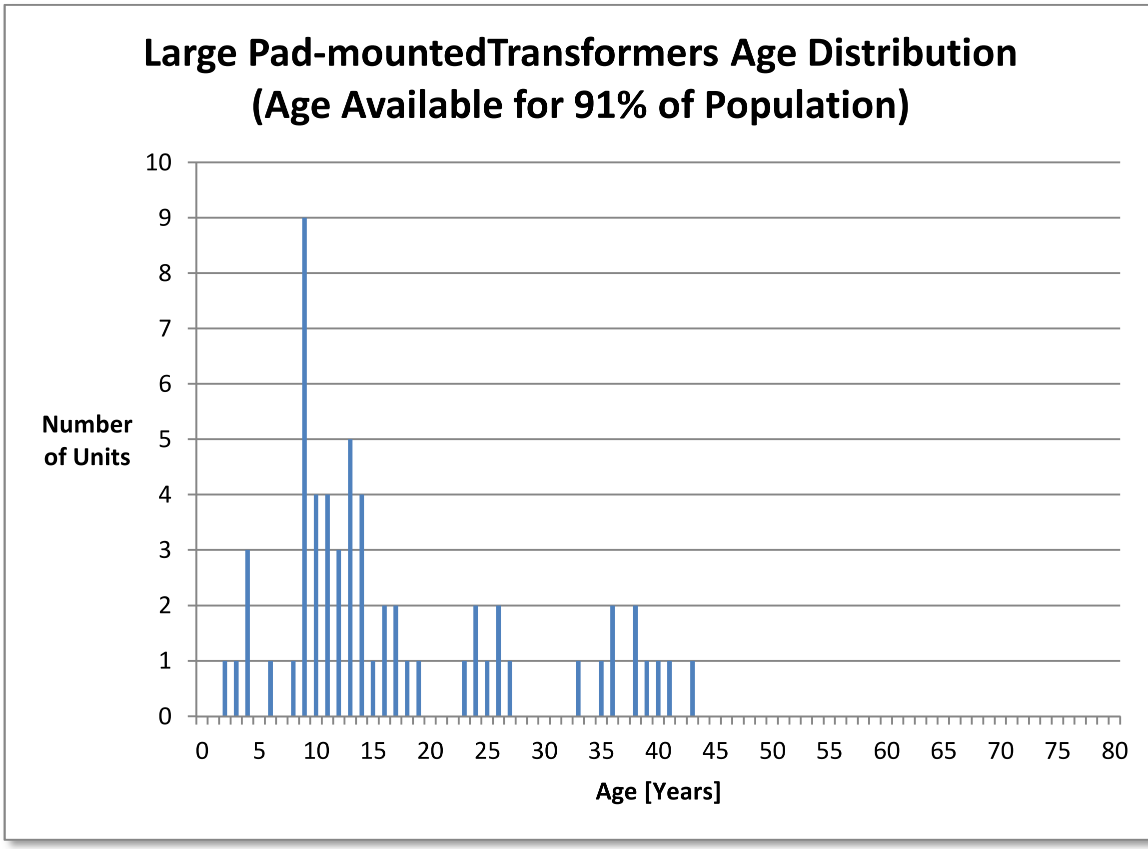

Figure 2-2 Large Pad-Mount Transformers Age Distribution

2.3 Health Index Results

At the time of assessment, there were 66 in service Large Pad-Mount Transformers at NPEI. Of these, 63 units had sufficient data for assessment.

The average Health Index for this asset group is 93%. None of the samples were in poor or very poor condition.

The Health Index Distribution is shown in below.

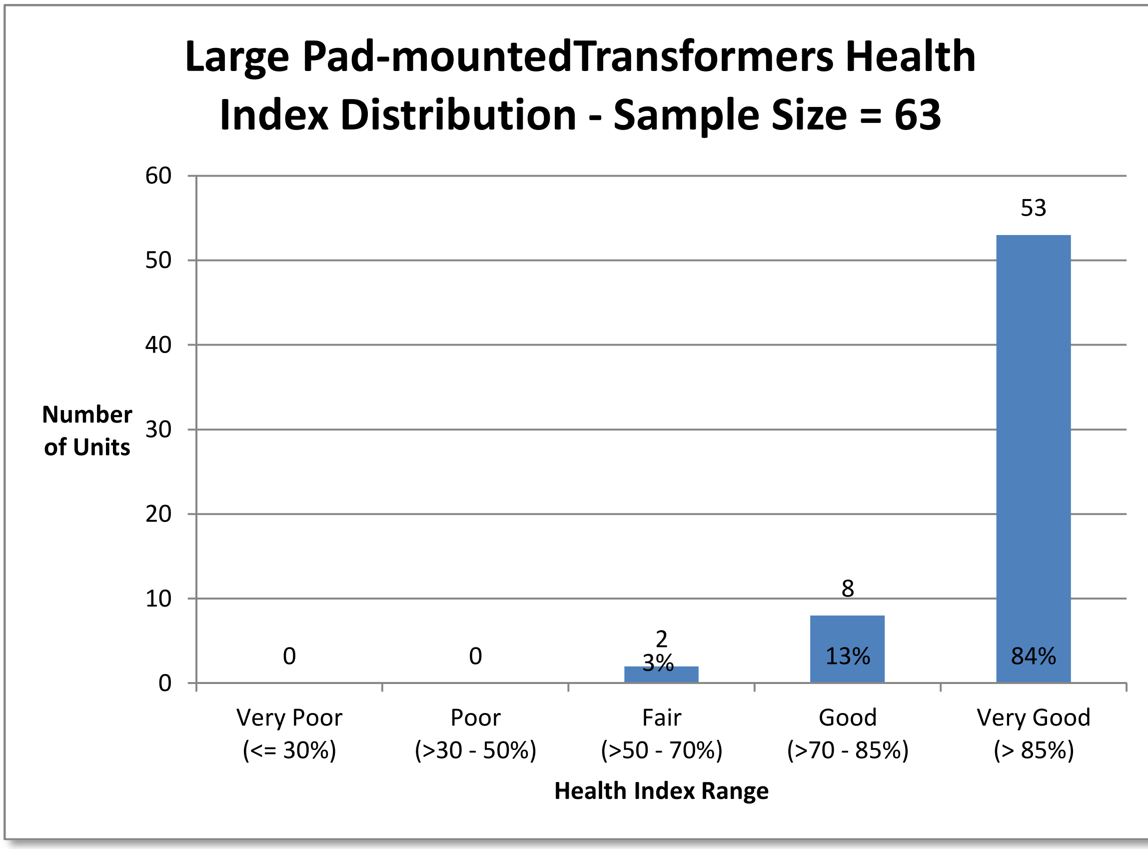

Figure 2-3 Large Pad-Mount Transformers Health Index Distribution

2.4 Condition-Based Flagged for Action Plan

While Large Pad-Mount Transformers are proactively and reactively addressed, the proactive approach was used in estimating the Flagged for Action Plan. Based on current condition (Health Index) of Large Pad-Mount Transformers and that the assumption that the rate of aging is constant (i.e. units do not continue to degrade faster than what would be typical), the Flagged for Action Plan is as follows. Because only one unit is flagged, levelization is not required.

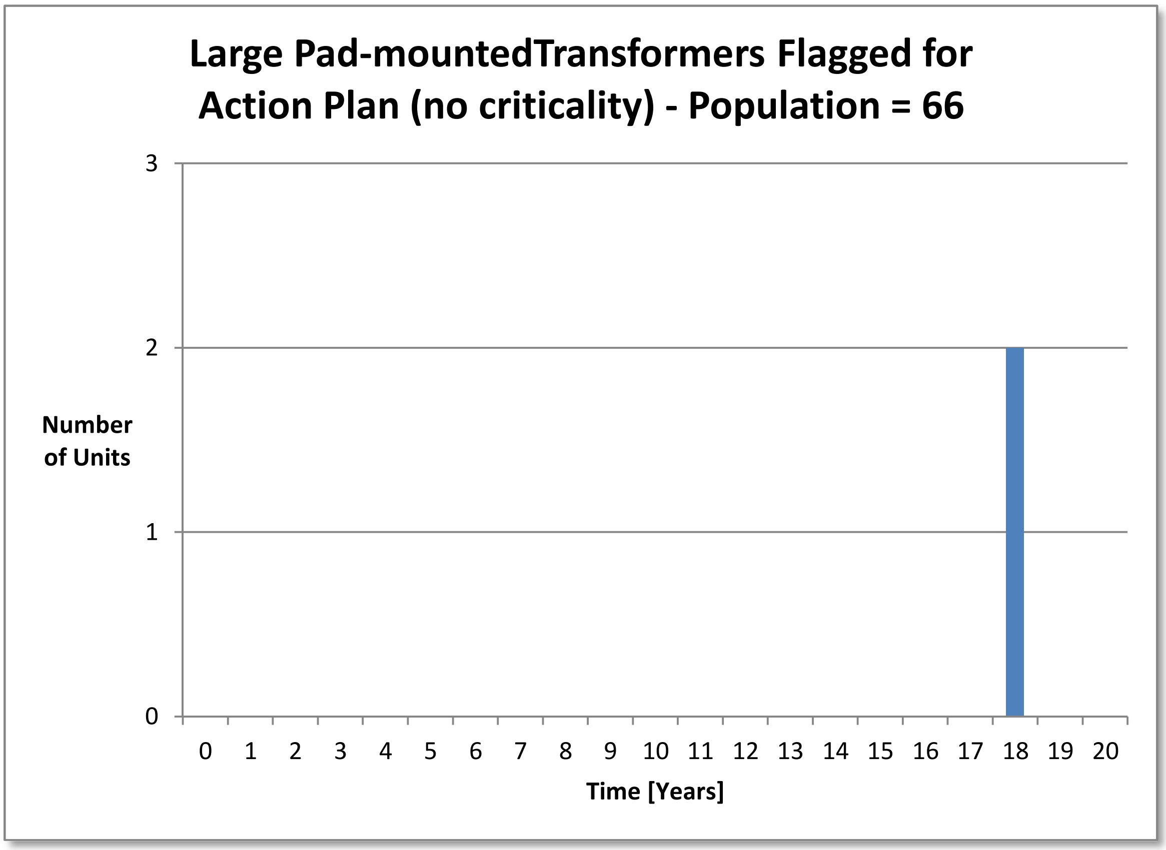

Figure 2-4 Large Pad-Mount Transformers Condition-Based Flagged for Action Plan

The detailed results, from lowest to highest Health Index are shown below:

Table 2-5 Results for Each Large Pad-Mount Transformers Unit

Transformer	Unit Number	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
79	4582	FLOIERA	17	100%	**64.6%**	Fair	18
17	800532	FACTORY OUTLET MALL	11	100%	**64.6%**	Fair	18
75	2529		14	43%	**74.8%**	Good	>20
52	732	FROST ROAD		14%	**75.0%**	Good	>20
101	800901-800924			14%	**75.0%**	Good	>20
34	800084	ALLENDALE A-175	43	100%	**77.7%**	Good	>20
40	800072	ARMOURY A-113	40	94%	**83.6%**	Good	>20
5	800126		33	100%	**83.9%**	Good	>20
42	800414	TGI FRIDAYS/MARRIOT	16	100%	**84.0%**	Good	>20
36	800413	SUPER 8 FERRY STREET	17	100%	**84.8%**	Good	>20
4	800105		39	100%	**88.0%**	Very Good	>20
15	800443	NPE BUILDING	15	100%	**88.4%**	Very Good	>20
27	800490	GOLDEN HORSESHOE	13	100%	**88.4%**	Very Good	>20
16	800546	NF COMM CENTRE	10	100%	**88.5%**	Very Good	>20
56	301	4655 BARTLETT	10	100%	**88.5%**	Very Good	>20
51	73201	PEARSON STREET	9	100%	**88.5%**	Very Good	>20
3	800109		27	94%	**88.6%**	Very Good	>20
103	800141	STOCK	38	100%	**88.7%**	Very Good	>20
63	8099	4758 CHRISTIE ST.	19	100%	**89.1%**	Very Good	>20
47	800128	STATION 52 CASINO NIAGRA	36	89%	**89.9%**	Very Good	>20
48	800129	STATION 52 CASINO NIAGRA	36	89%	**89.9%**	Very Good	>20
22	800135		35	29%	**91.1%**	Very Good	>20

Transformer	Unit Number	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
100	800-923		13	100%	**92.0%**	Very Good	>20
41	46	BUCKLEY TOWER	38	100%	**92.3%**	Very Good	>20
60	3176	4927 ONTARIO ST.	26	100%	**92.3%**	Very Good	>20
62	3040	SOUTH SERVICE RD	18	100%	**92.7%**	Very Good	>20
14	800526	DAYS INN VICTORIA AVE	11	100%	**92.8%**	Very Good	>20
72	629	TWENTY THIRD ST	11	100%	**92.8%**	Very Good	>20
106	800111		41	100%	**93.4%**	Very Good	>20
2	CHIPPAWA CREEK	NIAGRA REGION BIO	10	100%	**93.6%**	Very Good	>20
10	800587	GREAT WOLF LODGE	9	100%	**93.6%**	Very Good	>20
55	9201	BARTLETT ROAD (4306)	24	100%	**96.0%**	Very Good	>20
20	800430	SWAGELOK	16	100%	**96.3%**	Very Good	>20
67	494	HILLSIDE DRIVE (5050)	14	100%	**96.4%**	Very Good	>20
33	800515	DOUBLE TREE	12	100%	**96.4%**	Very Good	>20
61	599	ONTARIO ST (SOBEYS)	12	100%	**96.4%**	Very Good	>20
107	800591		9	100%	**96.4%**	Very Good	>20
46	800127	DAYS INN FALLVIEW	26	43%	**98.7%**	Very Good	>20
13	800197		25	43%	**98.9%**	Very Good	>20
26	800210	MANSIONS OF FOREST GLEN	24	43%	**99.1%**	Very Good	>20
80	4949	COURT VALVE	23	100%	**99.7%**	Very Good	>20
102	801000		13	29%	**99.8%**	Very Good	>20
74	202	JORDAN ROAD	14	43%	**99.8%**	Very Good	>20
18	800465	AMERICAN RESORT	14	100%	**99.9%**	Very Good	>20
50	77045	INDUSTRIAL PARK	13	100%	**99.9%**	Very Good	>20
53	81	FROST ROAD	13	94%	**99.9%**	Very Good	>20

Transformer	Unit Number	Station Name	Age	Transformer Data Availability	Transformer Health Index	Transformer Health Index Category	Flagged for Action (Years from now)
77	83005	REGIONAL ROAD 20 EAST	12	100%	**100.0%**	Very Good	>20
71	1652	SECOND AVE	11	100%	**100.0%**	Very Good	>20
43	800550	NIAGARA REGION	10	100%	**100.0%**	Very Good	>20
1	800568	FUTURE SHOP	9	100%	**100.0%**	Very Good	>20
7	800584	GREAT WOLF LODGE	9	100%	**100.0%**	Very Good	>20
8	800585		9	100%	**100.0%**	Very Good	>20
9	800586		9	100%	**100.0%**	Very Good	>20
11	800588	GREAT WOLF LODGE	9	100%	**100.0%**	Very Good	>20
12	800589	GREAT WOLF LODGE	9	100%	**100.0%**	Very Good	>20
6	800601		8	100%	**100.0%**	Very Good	>20
105	800638		6	100%	**100.0%**	Very Good	>20
19	800662	HODGSON ROLLING	4	100%	**100.0%**	Very Good	>20
82	800661	WALMART	4	100%	**100.0%**	Very Good	>20
84	800660	COMMISSOS FOOD	4	100%	**100.0%**	Very Good	>20
83	800674	LOWES	3	100%	**100.0%**	Very Good	>20
108	B00699	NPE YARD	2	100%	**100.0%**	Very Good	>20
59	546	4927 ONTARIO ST.		14%	**100.0%**	Very Good	>20
37	800147	EVENTIDE HOME		0%			
57	0	NO NAMEPLATE		0%			
68	99121	NORTH SERVICE RD		0%			

2.5 Data Analysis

The type of data available for large pad-mounted transformers include oil quality and dissolved gas analysis, as well as age and limited inspection records related to tank condition and leaks. More detailed inspections were not available for this asset group.

2.5.1 Data Gaps

Although ultrasonic and infrared tests are regularly conducted for this asset group, the results of such tests have yet to be incorporated into the Health Indexing process.

Additionally, parameters that can be included in the Health Index formula follow.

Table 2-6 Large Pad-Mount Transformers Data Gaps

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Bushing		☆☆	Bushing	Visible issues	Visual Inspection
Loading	Service Record	☆☆	Transformer Loading	Loading history (e.g. monthly 15 minute peaks)	Operations records.

2.5.2 Data Availability Distribution

Nearly all units had age, oil quality, and DGA tests, and some inspection records available. The average DAI for Large Pad-Mount Transformers, as measured against the existing Health Index formula/data set, is 84%.

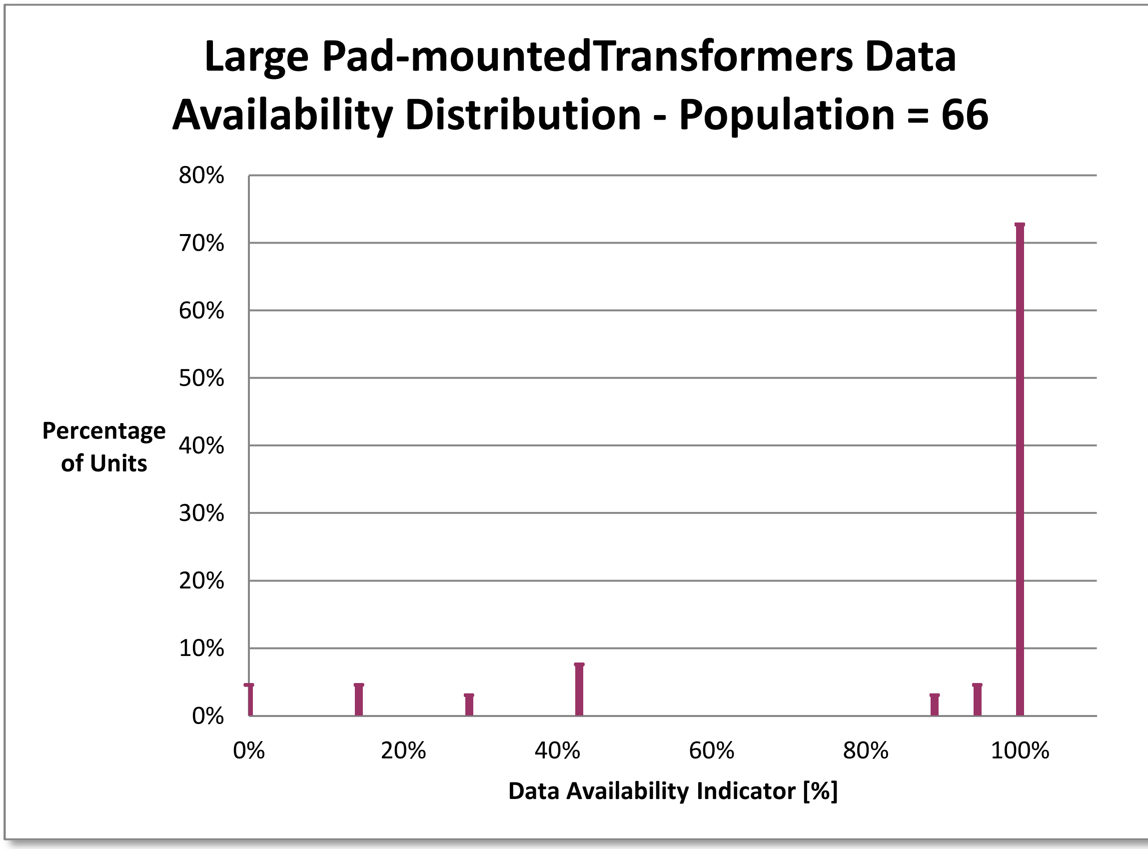

Figure 2-5 Large Pad-Mount Transformers Data Availability Distribution

3 Pole-Mounted Transformers

3.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Pole-Mounted Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

3.1.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Parameters and Weights

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Service Record	1	1	Number of Customers	1	Table 3-2
			2	Age	2	Figure 3-1

3.1.2 Condition Parameter Criteria

Number of Customers

Table 3-2 Number of Customers Condition Criteria

CPF	Description
4	0-9
3	10-14
2	15-19
0	20+

Age

Assume that the failure rate for Pole-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 60 years the probability of failures (P_f) for this asset are 20% and 90% respectively results in the failure and survival curves shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

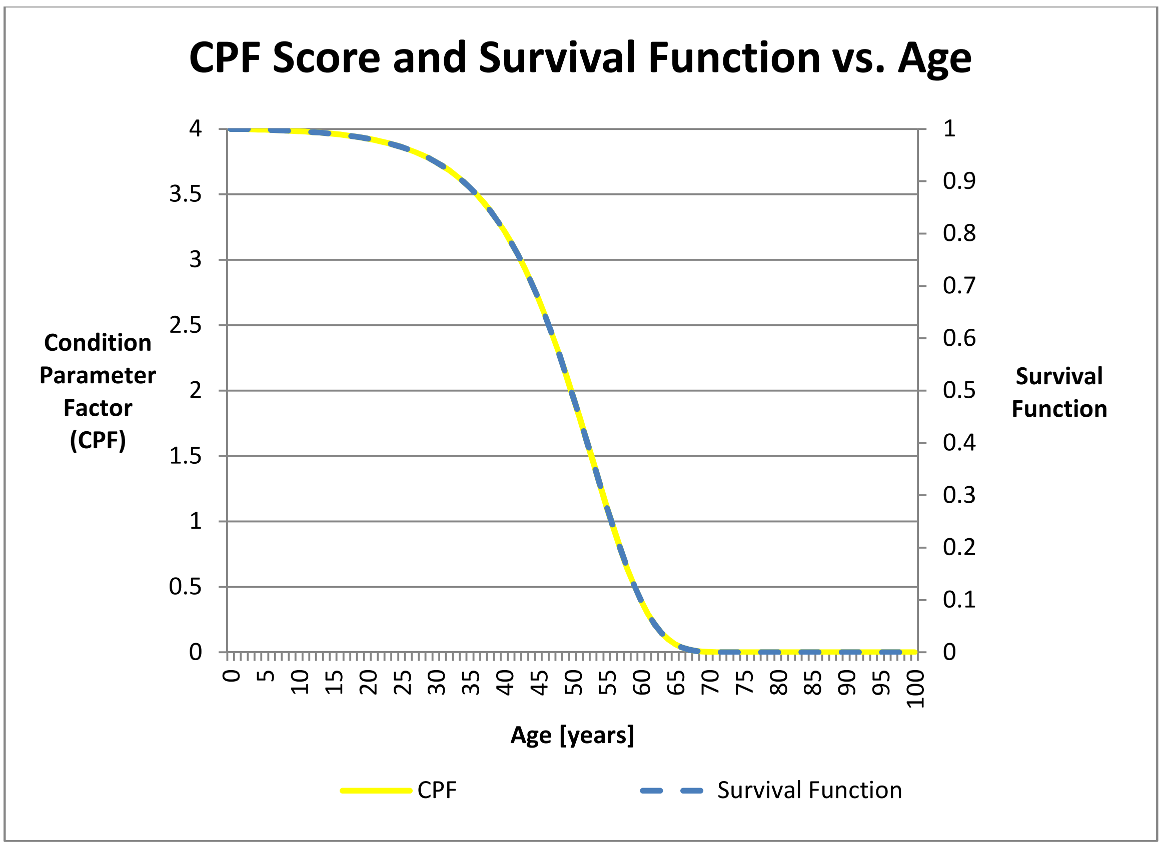

Figure 3-1 Age Condition Criteria

3.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 71% of the population. The average age was found to be 22 years.

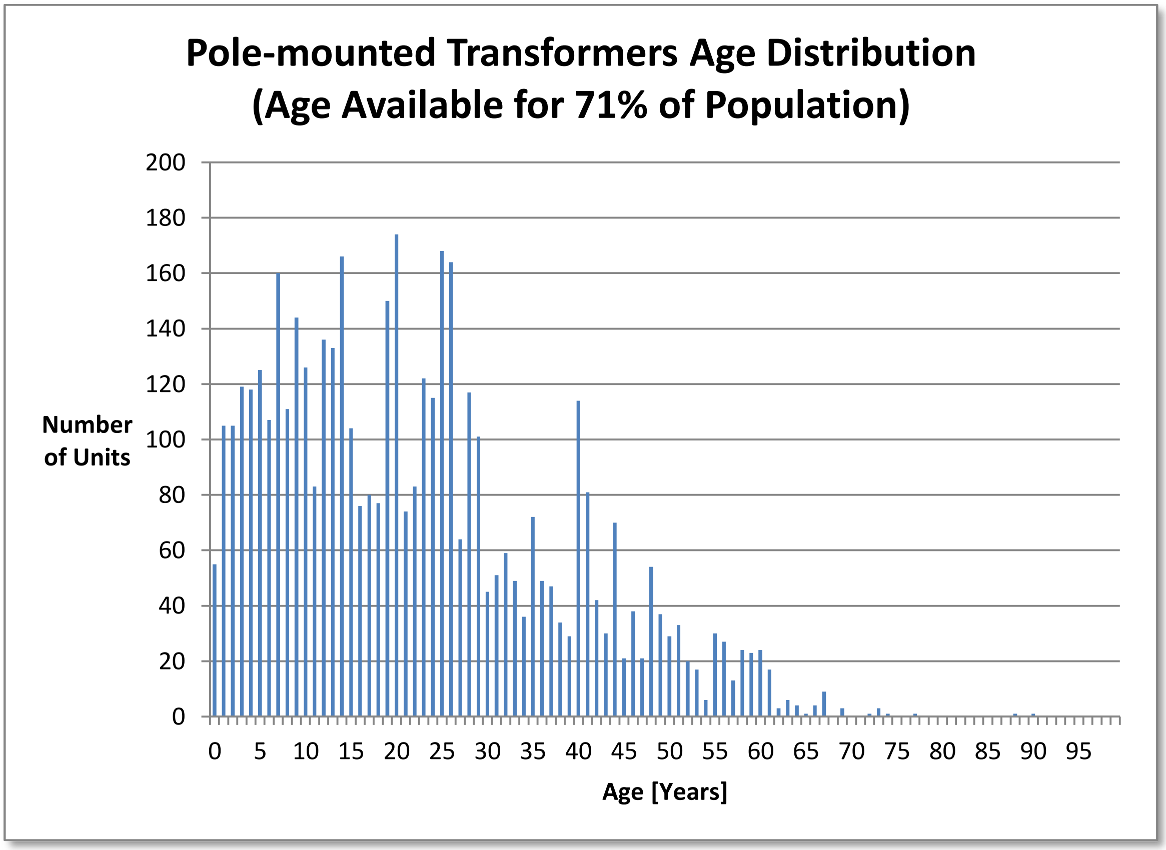

Figure 3-2 Pole-Mounted Transformers Age Distribution

3.3 Health Index Results

At the time of assessment, there were 6683 in service Pole-Mounted Transformers at NPEI. There were 6648 units with sufficient data for assessment.

The average Health Index for this asset group is 92%. Approximately 3% of the units were found to be in very poor to poor condition.

The Health Index Results are as follows:

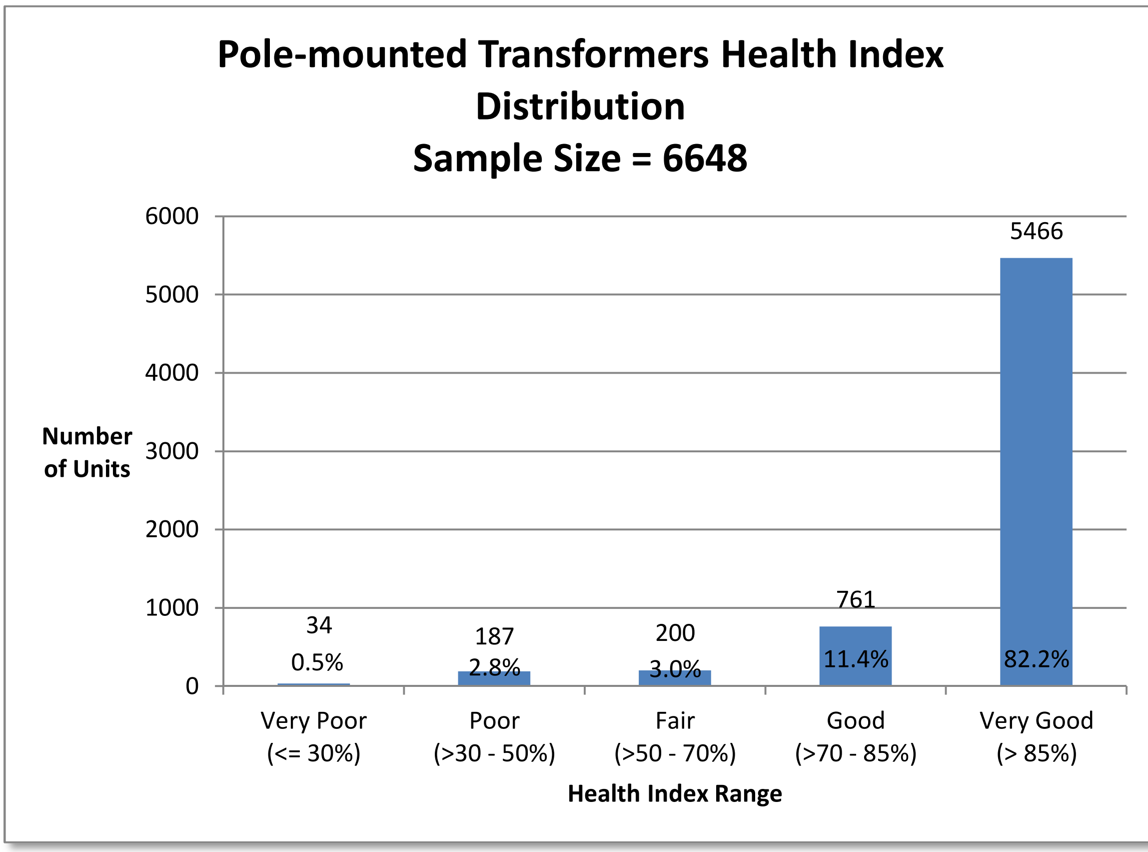

Figure 3-3 Pole-Mounted Transformers Health Index Distribution

3.4 Condition-Based Flagged for Action Plan

As it is assumed that Pole-Mounted Transformers are reactively addressed, the Flagged for Action Plan is based on the asset failure rate, f(t).

The Flagged for Action Plan is based on the expected number of units that require action in a given year. As it may not always be feasible to address assets as per the optimal plan, a “levelized” plan, based on accelerating action prior to expected time of action, is also given.

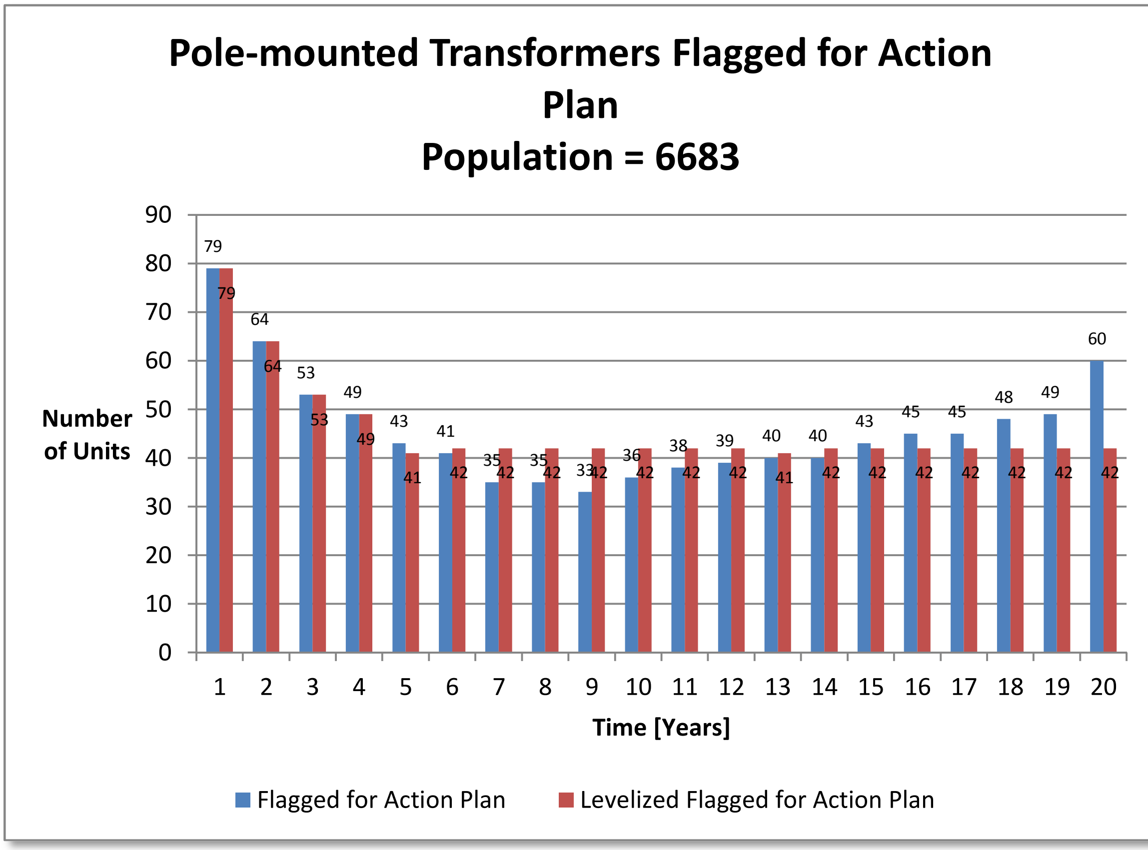

Figure 3-4 Pole-Mounted Transformers Flagged for Action Plan

3.5 Data Analysis

Age was the only data available for Pole-Mounted Transformers. Although inspections are regularly conducted, results of inspections have yet to be incorporated into the Health Indexing process.

3.5.1 Data Gap

The following data gaps have been identified:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Tank Corrosion	Physical Condition	☆☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection
Connection		☆☆	Transformer connection	Poor connection	Visual inspection
Grounding		☆	Transformer tank	Poor grounding wire connection	Visual inspection
Bushing		☆☆	Bushing	Crack / Dirt	Visual inspection
Overall	Service Record	☆☆☆	Transformer	General status evaluation based on routine operation and inspection	Visual inspection
Loading		☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation Record

3.5.2 Data Availability Distribution

As a majority of units had age and number of customers, the average DAI for Pole-Mounted Transformers, as measured against the existing data set, is 64%.

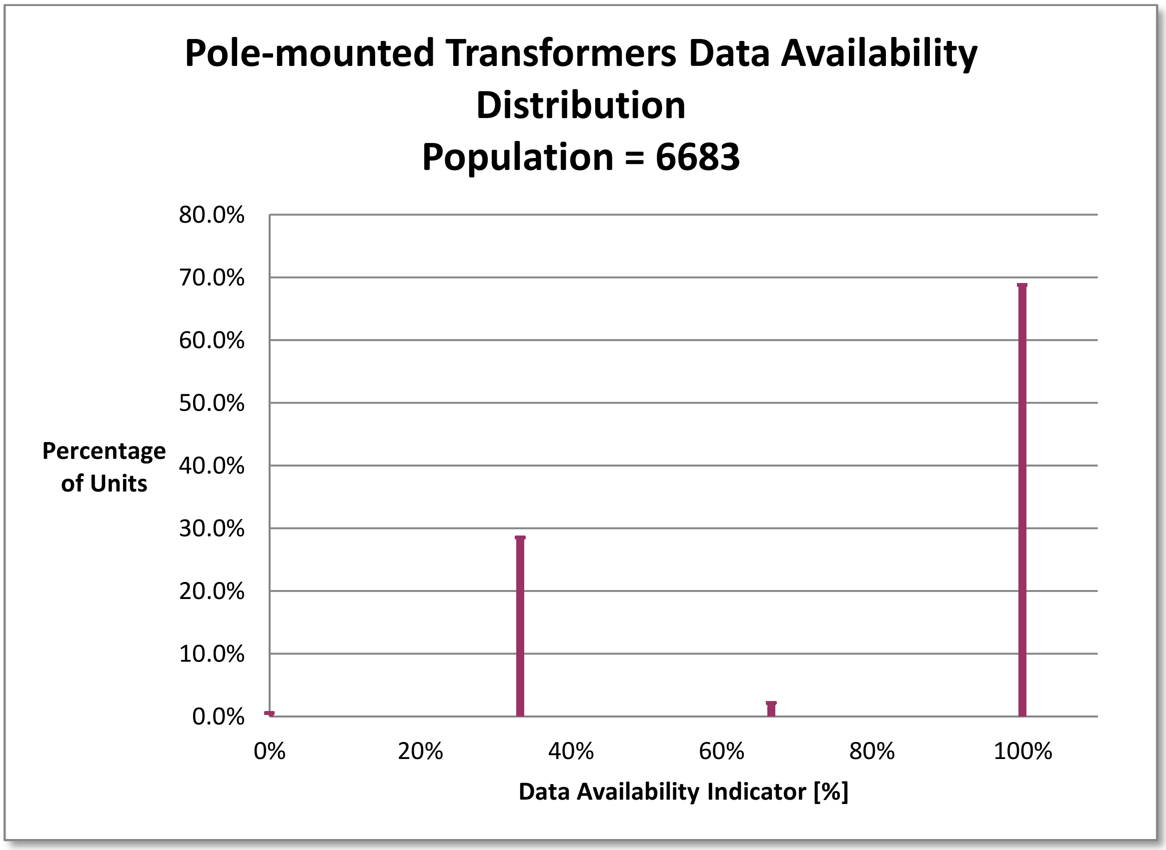

Figure 3-5 Pole-Mounted Transformers Data Availability Distribution

4 Wood Poles

4.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Wood Poles. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

4.1.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Parameters and Weights

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Physical Condition	3	1	Animal Damage	2	Table 4-2
			2	Lean	1	Table 4-2
			3	Rot / Soft	2	Table 4-2
			4	Crack	2	Table 4-2
			5	Hole / Void	2	Table 4-2
			6	Hollow	2	Table 4-2
			7	Chunk	2	Table 4-2
			8	Damp / Wet	2	Table 4-2
			9	Bend / Hit / Damage	2	Table 4-2
			10	Poor Top	2	Table 4-2
2	Accessories	1	1	Ground	2	Table 4-2
			2	Cross Arm	1	Table 4-2
			3	Guy Wires	3	Table 4-2
			4	Cable Guard	1	Table 4-2
3	Service Record	4	1	Age	1	Figure 4-1
De-Rating Multiplier		Western Butt Treated Cedar			0.8	

4.1.2 Condition Parameter Criteria

Visual Inspections

Table 4-2 Sample Inspection Condition Criteria

CPF	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate for Wood Poles exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 50 and 60 years the probability of failures (P_f) for this asset are 20% and 90% respectively results in the failure and survival curves shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

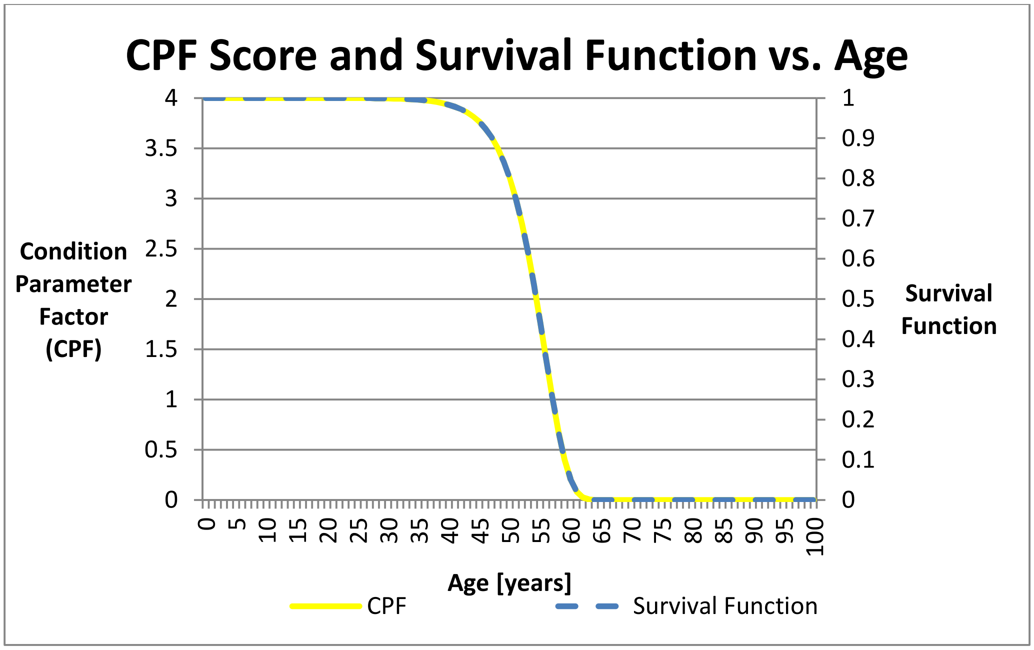

Figure 4-1 Wood Poles Age Condition Criteria

4.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 75% of the population. The average age was found to be 30 years.

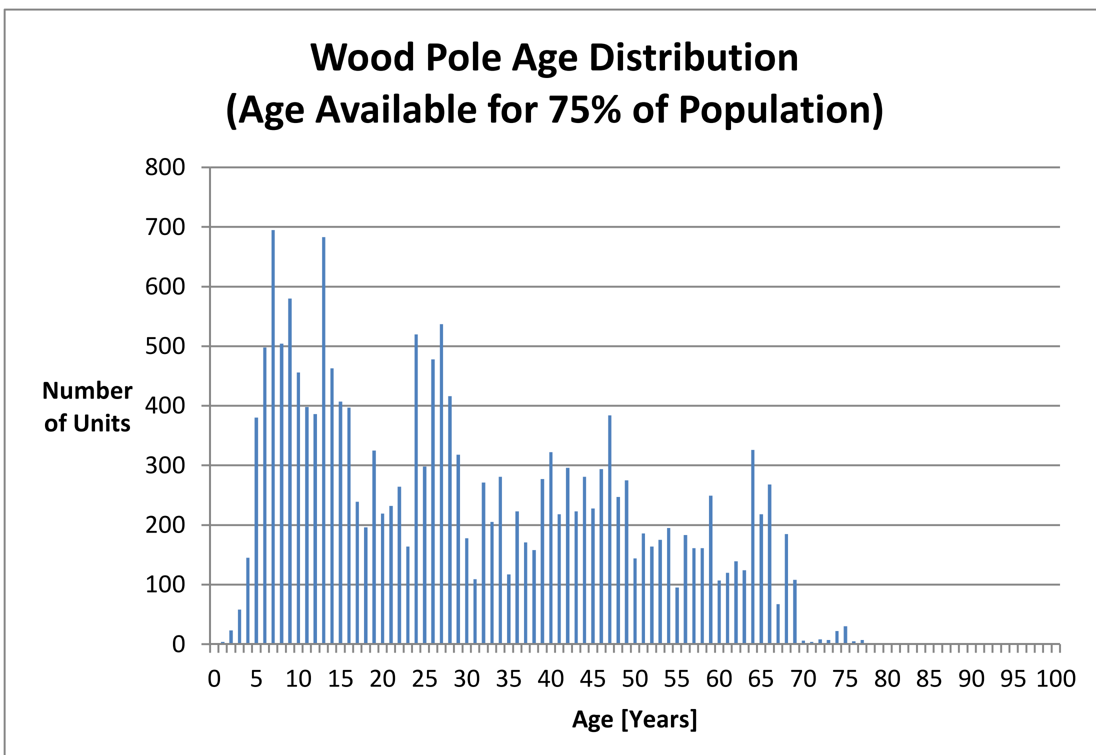

Figure 4-2 Wood Poles Age Distribution

4.3 Health Index Results

At the time of assessment, there were 24546 in service Wood Poles at NPEI. There were 23610 units with sufficient data for assessment.

The average Health Index for this asset group is 95%. Approximately 3% of the units were found to be in very poor to poor condition.

The Health Index Results are as follows:

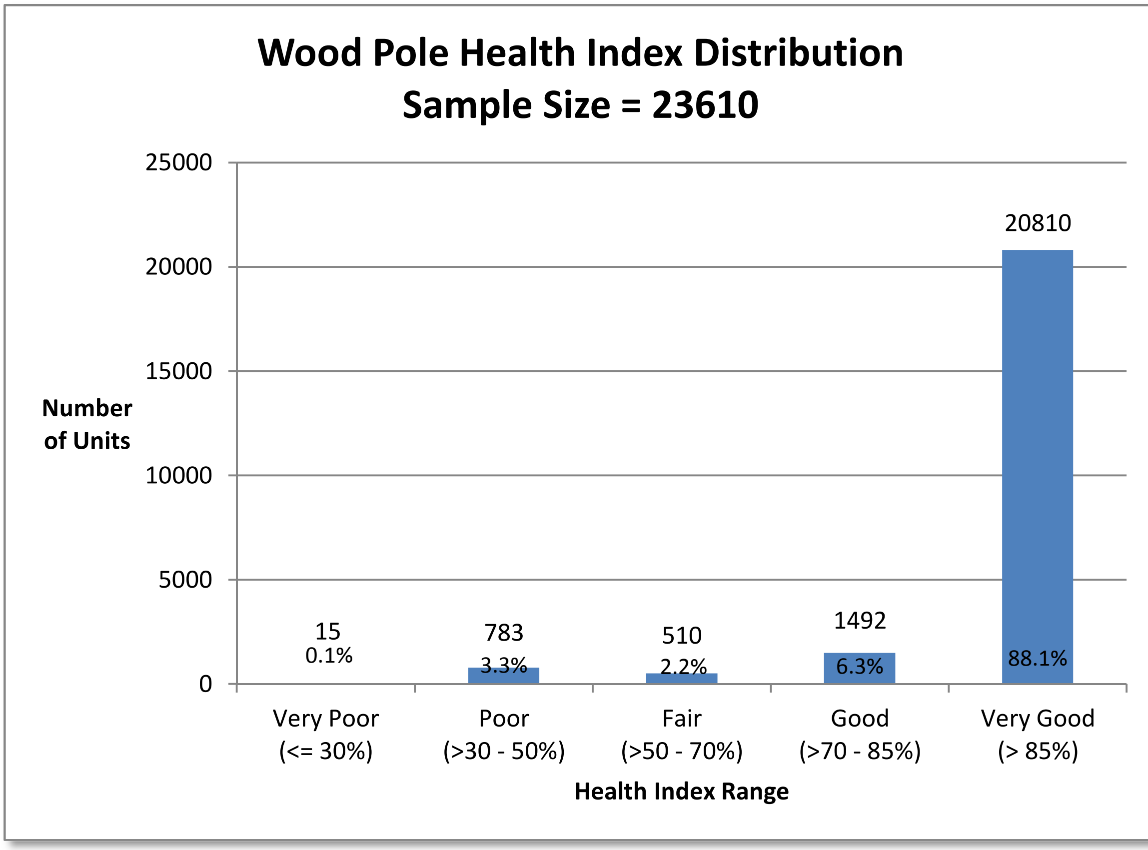

Figure 4-3 Wood Poles Health Index Distribution

4.4 Condition-Based Flagged for Action Plan

While Wood Poles are both proactively and reactively addressed, the Flagged for Action Plan is based on the asset failure rate, f(t).

The Flagged for Action Plan is based on the expected number of units that require action in a given year. As it may not always be feasible to address assets as per the optimal plan, a "levelized" plan, based on accelerating action prior to expected time of action, is also given.

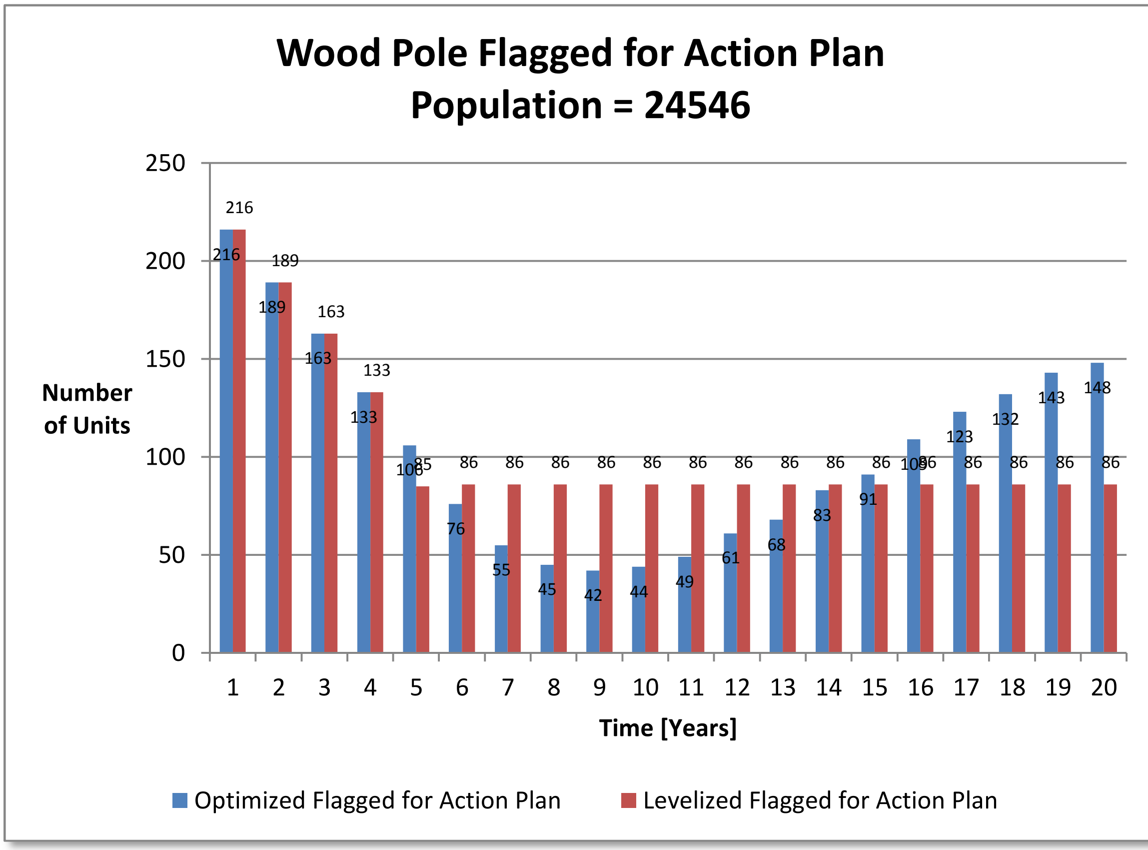

Figure 4-4 Wood Poles Flagged for Action Plan

4.5 Data Analysis

The data available for Wood Poles includes age and inspection data related to physical condition.

4.5.1 Data Gaps

The only other data recommended is pole strength data.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Pole Strength	Pole Strength	☆☆☆	Pole	Ratio of actual circumference over the original circumference	On-site testing

4.5.2 Data Availability Distribution

A majority of the population had age and inspections. The average DAI for Wood Poles, as measured against the existing data set, is 69%.

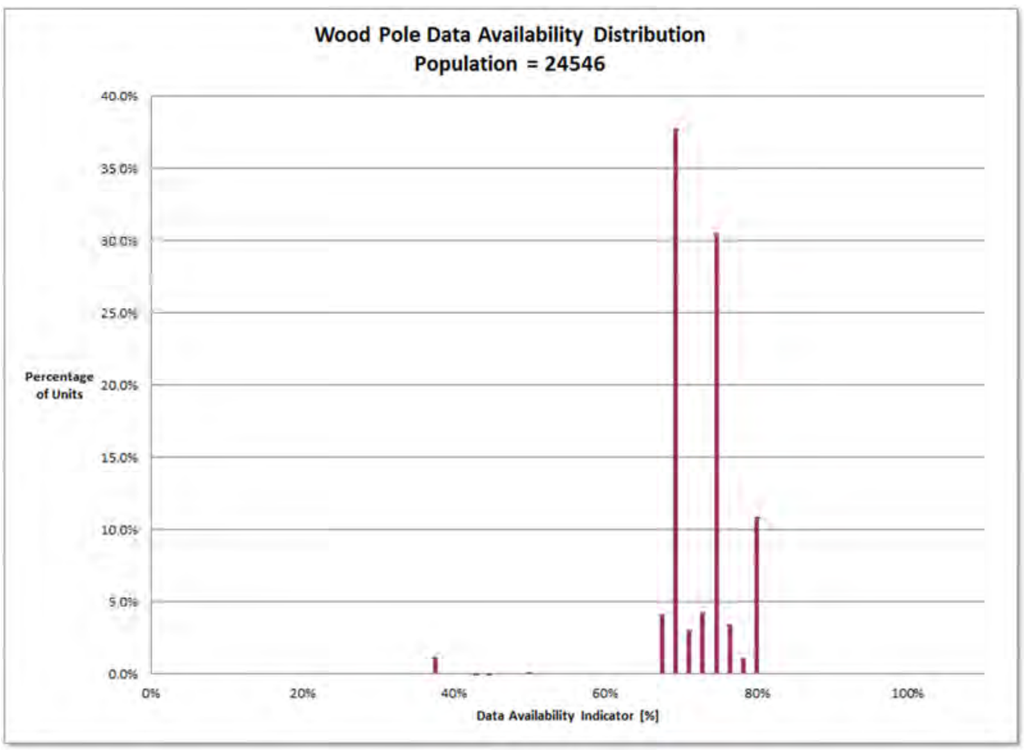

Figure 4-5 Wood Poles Data Availability Distribution

5 Pad-Mounted Transformers

5.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Pad-Mounted Transformers. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

5.1.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Parameters and Weights

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Physical Condition	3	1	Corrosion	3	Table 5-2
			2	Access	1	Table 5-2
			3	Base	2	Table 5-2
2	Connection and Insulation	5	1	Oil Leak	1	Table 5-2
			2	Grounding	2	Table 5-2
			3	Insulation	2	Table 5-2
3	Service Record	5	1	Number of Customers	1	Table 5-2
			2	Age	2	Figure 5-1
4	Tests	10	3	IR	1	Table 5-2
			2	Ultrasound	1	Table 5-2

5.1.2 Condition Parameter Criteria

Visual Inspections

Table 5-2 Sample Inspection Condition Criteria

CPF	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate for Pad-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 90% respectively results in the failure and survival curves shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

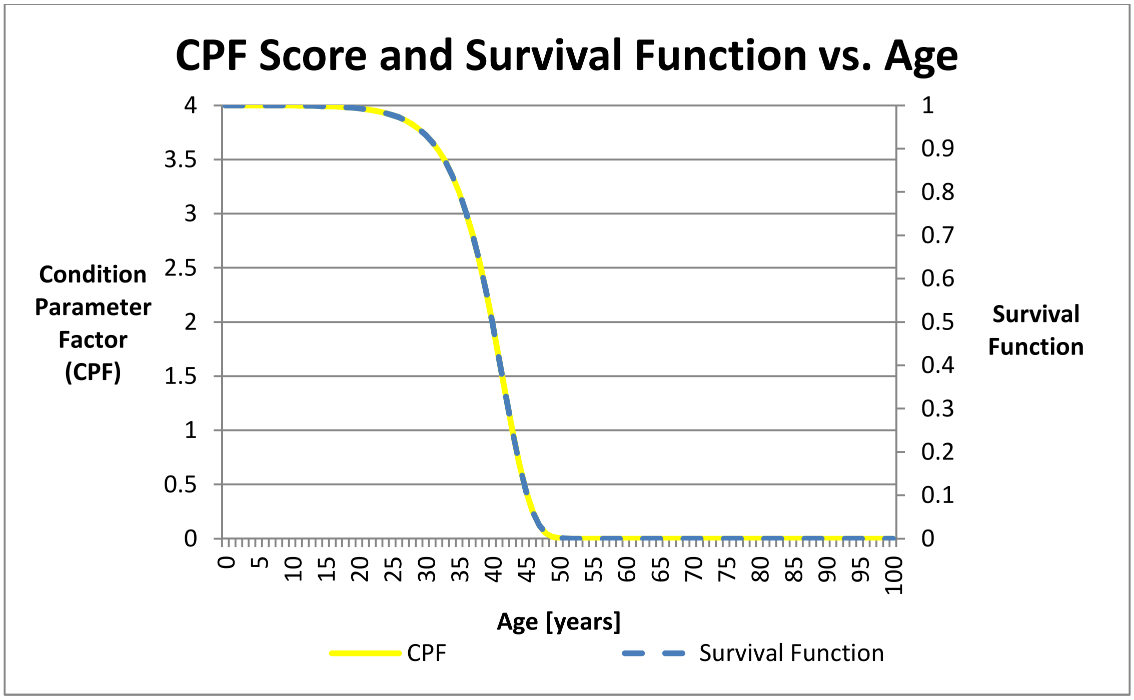

Figure 5-1 Pad-Mounted Transformers Age Condition Criteria

5.2 Age Distribution

The age distribution is shown in the figure below. Age was available for 99% of the population. The average age was found to be 15 years.

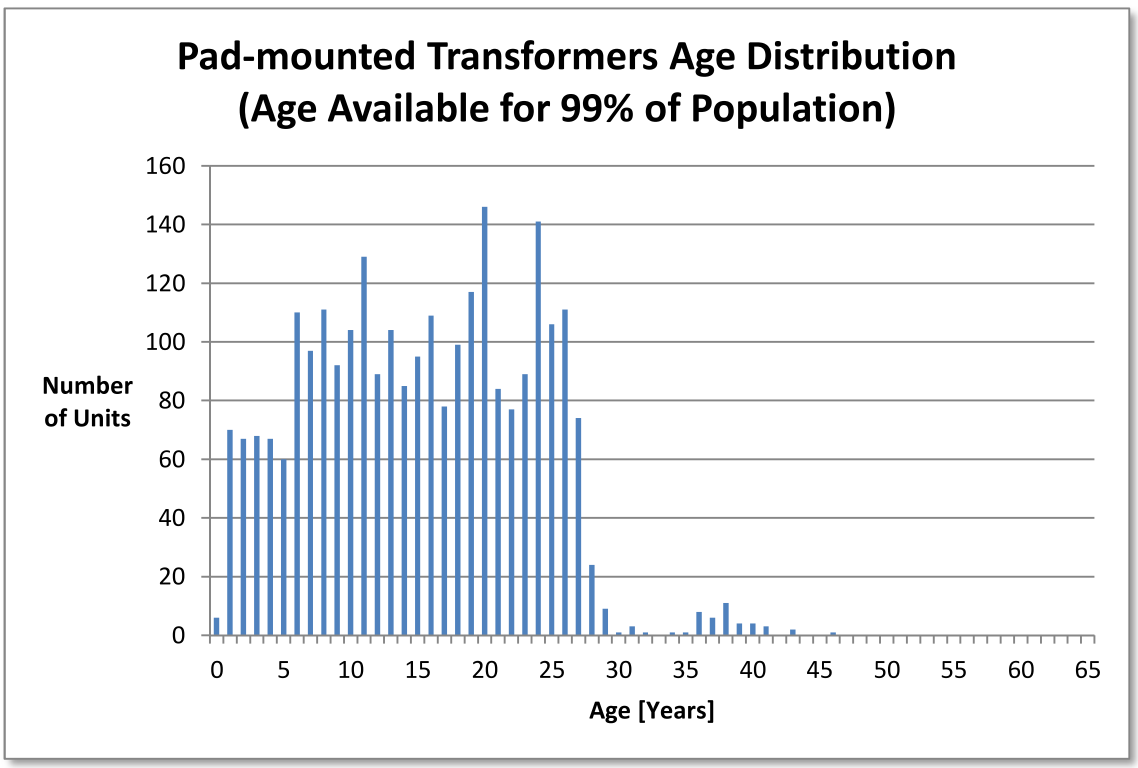

Figure 5-2 Pad-Mounted Transformers Age Distribution

5.3 Health Index Results

At the time of assessment, there were 2682 in service Pad-Mounted Transformers at NPEI. There were 2682 units with sufficient data for assessment.

The average Health Index for this asset group is 97%. Approximately <1% of the units were found to be in very poor to poor condition.

The Health Index Results are as follows:

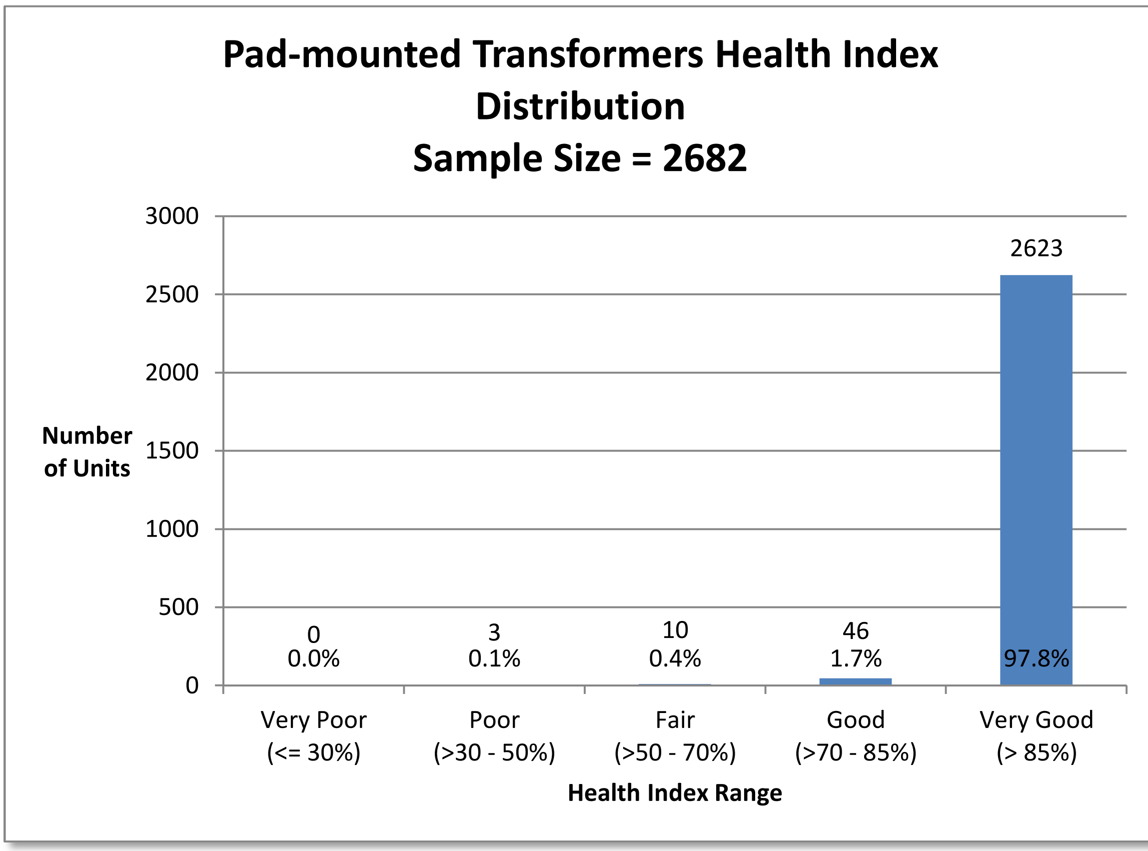

Figure 5-3 Pad-Mounted Transformers Health Index Distribution

5.4 Condition-Based Flagged for Action Plan

While Pad-Mounted Transformers are both proactively and reactively addressed, the Flagged for Action Plan is based on the asset failure rate, f(t).

The Flagged for Action Plan is based on the expected number of units that require action in a given year. As it may not always be feasible to address assets as per the optimal plan, a "levelized" plan, based on accelerating action prior to expected time of action, is also given.

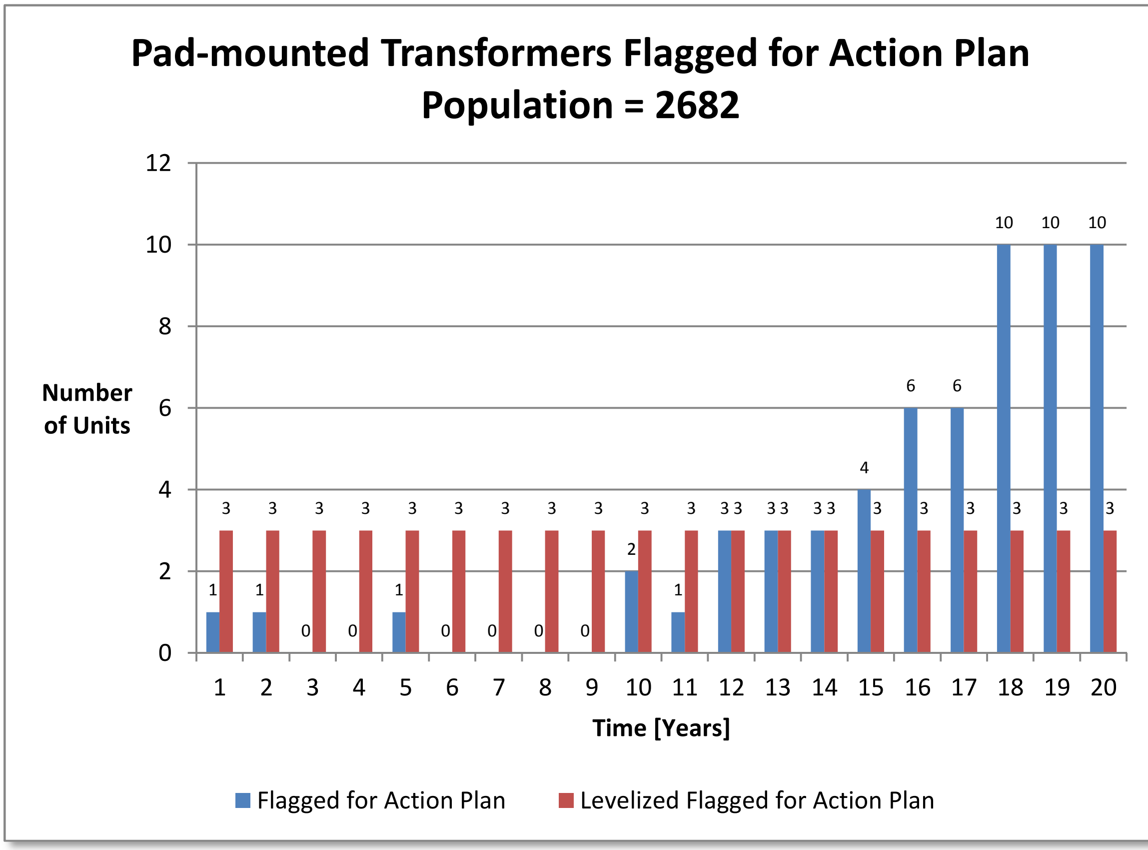

Figure 5-4 Pad-Mounted Transformers Flagged for Action Plan

5.5 Data Analysis

Condition data gathered from inspections include status of transformer enclosure, base, grounding, insulation, as well as infrared and ultrasonic scans. Age and number of customers were also available for pad-mounted transformers.

5.5.1 Data Gaps

The data gap for this asset category is as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Loading	Service Record	☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation record

5.5.2 Data Availability Distribution

An large majority of units had age, inspection records, and test records. As such, the average DAI for Pad-Mounted Transformers, as measured against the existing data set, is 90%.

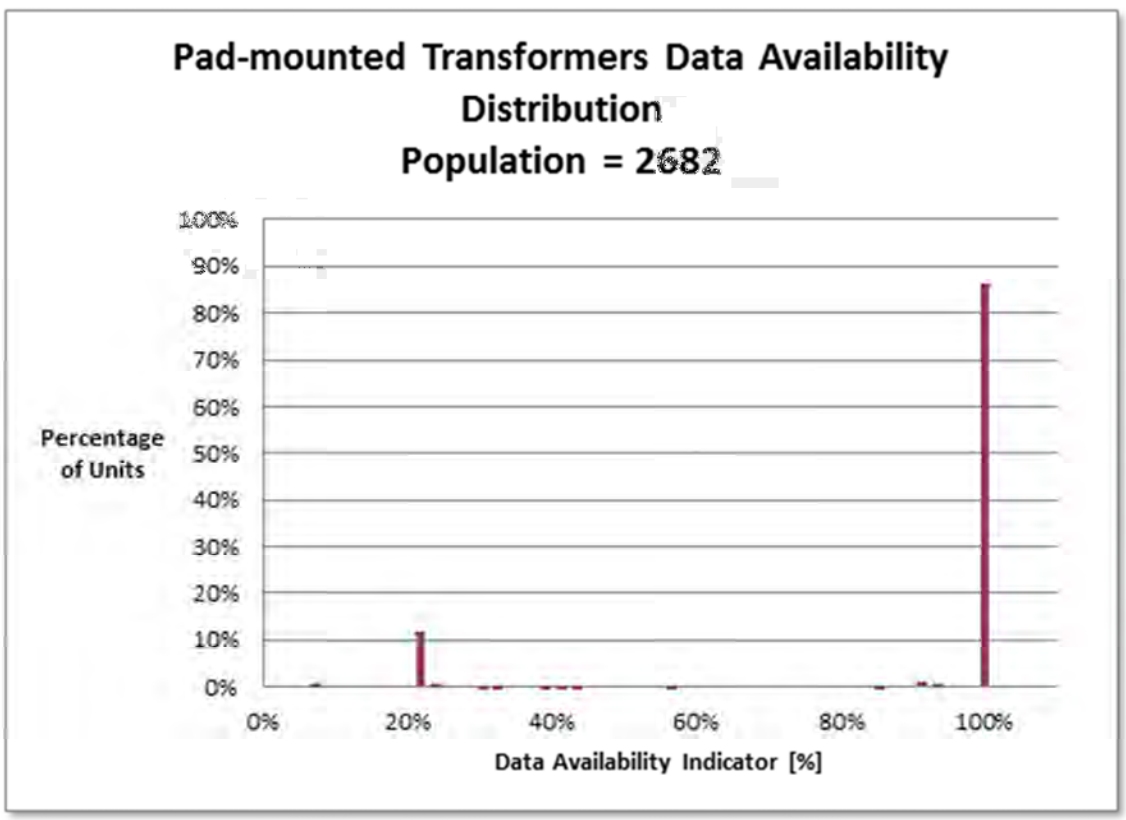

Figure 5-5 Pad-Mounted Transformers Data Availability Distribution

6 Pad-Mounted Switchgear

6.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Pad-Mounted Switchgear. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

6.1.1 Condition and Sub-Condition Parameters

Table 6-1 Condition Parameters and Weights

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Physical Condition	3	1	Corrosion	3	Table 6-2
			2	Access	1	Table 6-2
			3	Base	2	Table 6-2
2	Connection and Insulation	5	1	Oil Leak	1	Table 6-2
			2	Grounding	1	Table 6-2
			3	Insulation	1	Table 6-2
3	Service Record	5	1	Action Required	1	Table 6-2
			2	Inspection Result	1	Table 6-2
4	Tests	10	3	IR	1	Table 6-2
			2	Ultrasound	1	Table 6-2

6.1.2 Condition Parameter Criteria

<u>**Visual Inspections**</u>

Table 6-2 Sample Inspection Condition Criteria

CPF	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

6.2 Age Distribution

Age data is unavailable for Pad-Mounted Switchgear.

6.3 Health Index Results

At the time of assessment, there were 74 in service Pad-Mounted Switchgear at NPEI. There were 60 units with sufficient data for assessment.

The average Health Index for this asset group is 81%. Approximately 2% of the units were found to be in very poor to poor condition.

The Health Index Results are as follows:

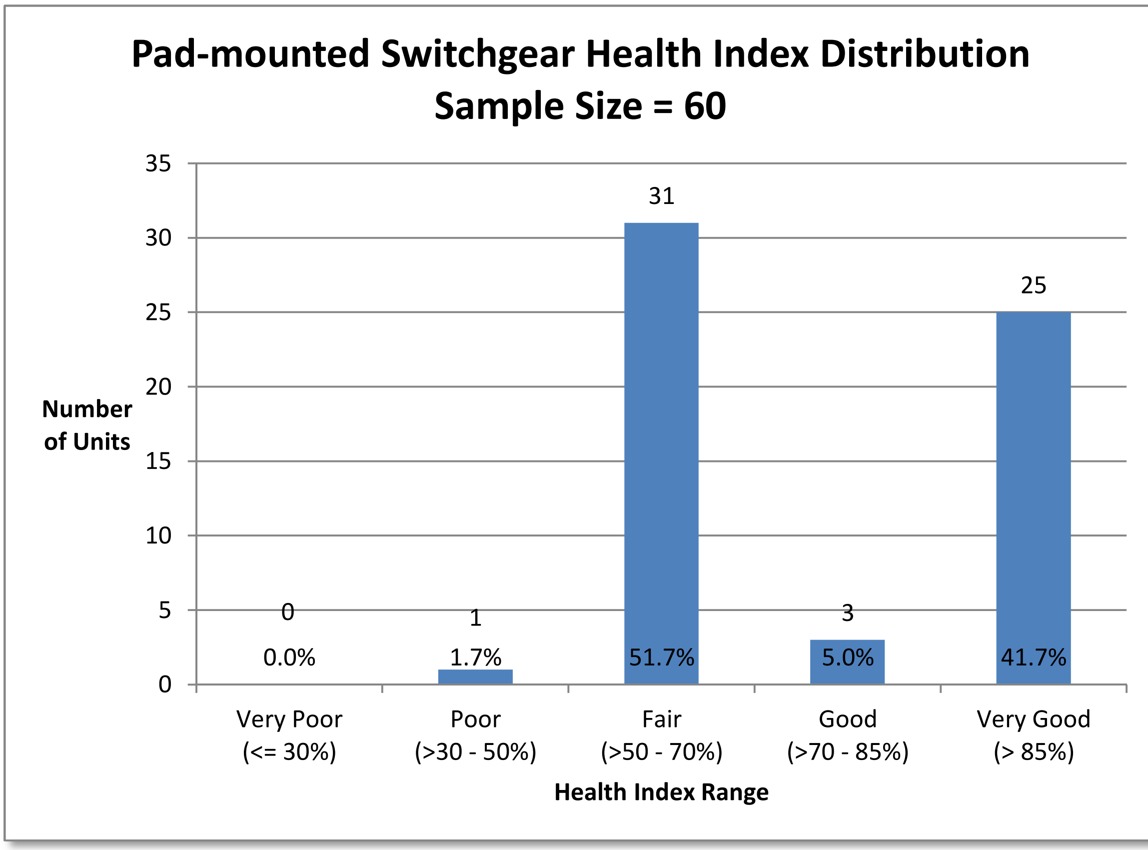

Figure 6-1 Pad-Mounted Switchgear Health Index Distribution

6.4 Condition-Based Flagged for Action Plan

Although it is assumed that Pad-Mounted Switchgear are reactively addressed, the Flagged for Action Plan is based on the asset failure rate, f(t). The assumptions used to calculate f(t) are as follows:

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

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

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

P_f = cumulative probability of failure

It has been observed in NPEI that air insulated Pad-Mounted Switchgear typically have shorter useful lives than that of gas insulated units. To account for this, different failure curves were used for air and gas units. For air insulated switchgear, it was assumed that 20 and 25 years have 20% and 90% probabilities of failure respectively. For gas insulated switchgear, it was assumed that 30 and 45 years have 20% and 90% probabilities of failure respectively.

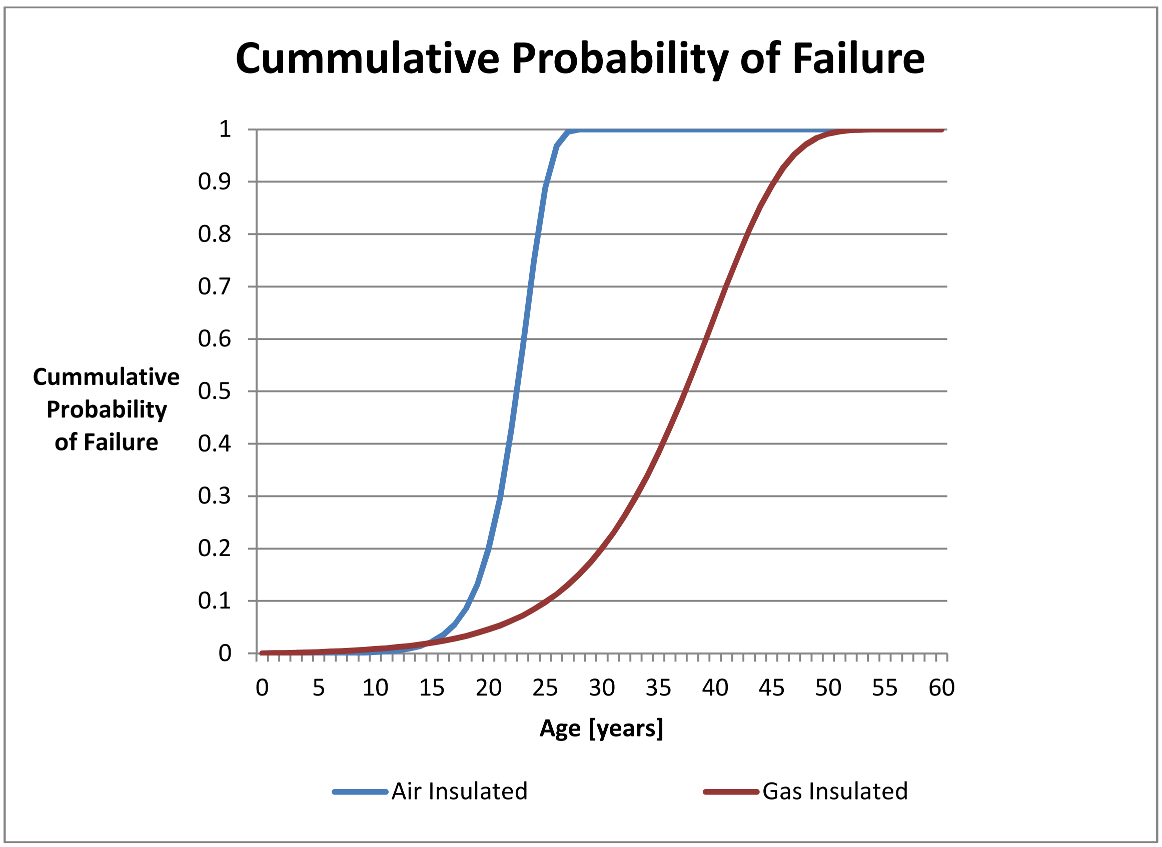

Figure 6-2 Pad-Mounted Switchgear Cumulative Failure Curve

The Flagged for Action Plan is based on the expected number of units that require action in a given year. As it may not always be feasible to address assets as per the optimal plan, a "levelized" plan, based on accelerating action prior to expected time of action, is also given.

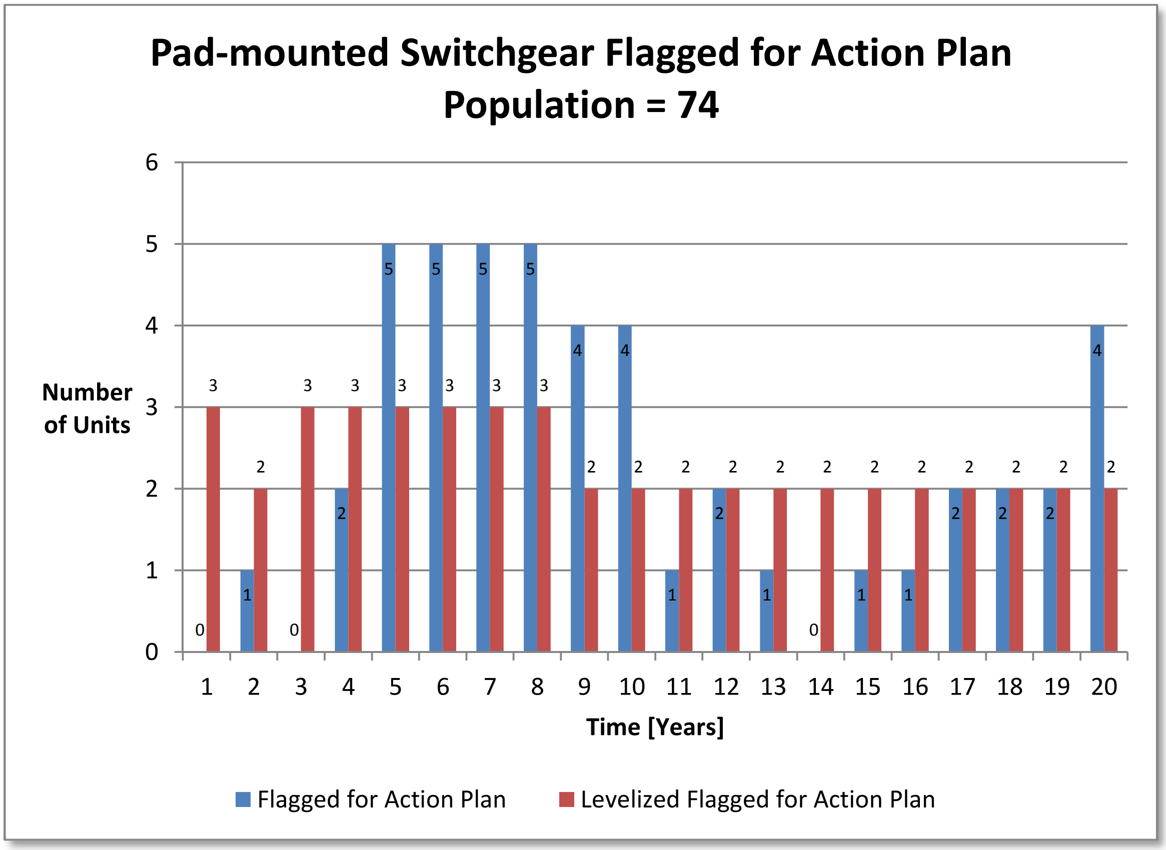

Figure 6-3 Pad-Mounted Switchgear Flagged for Action Plan

6.5 Data Analysis

The data available for Pad-Mounted Switchgear comes from Inspections and includes condition of enclosure, base, insulation, grounding, and overall switchgear condition. Infrared and ultrasonic tests are also available for this asset group.

6.5.1 Data Gaps

The data gaps are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Switch	Switch/Fuse Condition	✯ ✯	Switch	Misalignment, signs of arcing	Visual inspection
Arc Suppressor		✯ ✯	Switch arc extinction	Arc extinction part surface worn-out	Visual inspection
Fuse		✯ ✯	Fuse	Fuse visual condition	Visual inspection
Elbows/Inserts		✯ ✯	Connection	Poor connection / hot spots	Visual inspection or IR scan

6.5.2 Data Availability Distribution

Most of the units had inspection records. As such, the average DAI for Pad-Mounted Switchgear, as measured against the existing data set, is 78%.

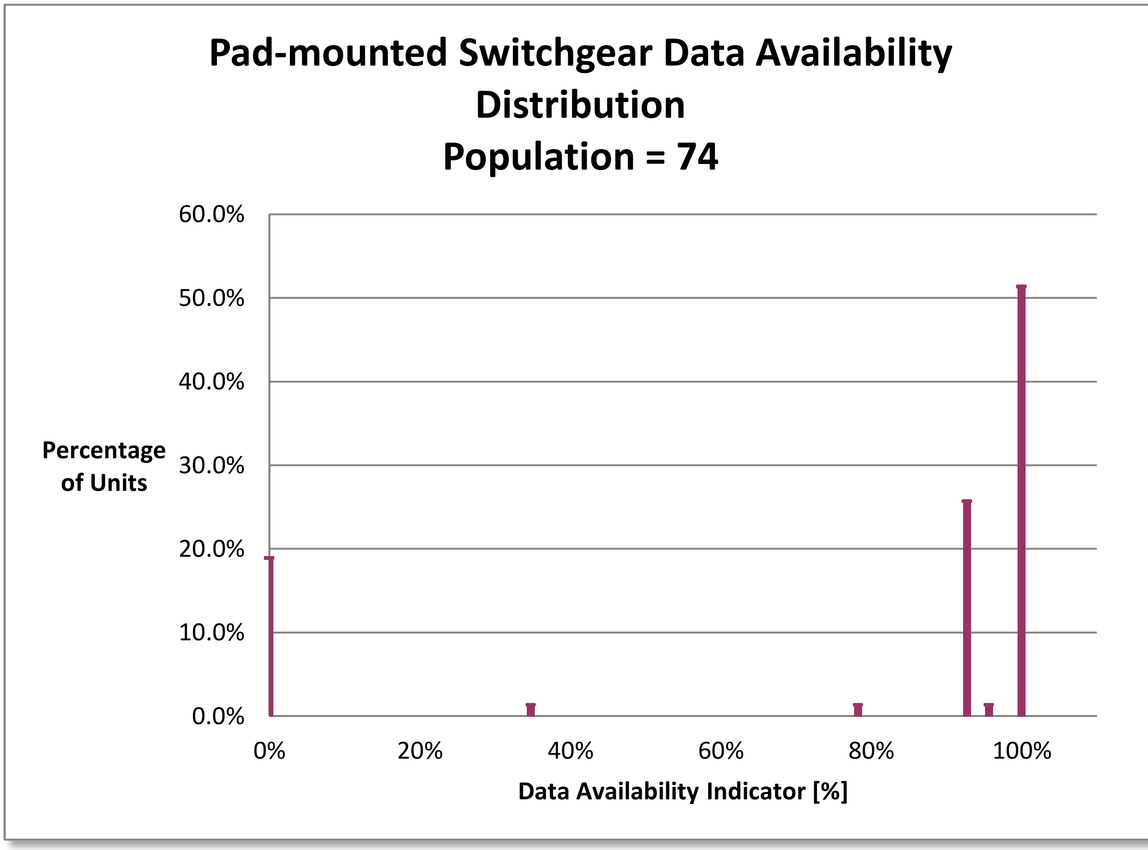

Figure 6-4 Pad-Mounted Switchgear Data Availability Distribution

7 Underground Cables

NPEI's Underground Cables asset category is broken down into two sub-categories: Main Feeders and Distribution.

7.1 Health Index Formulation

This section presents the Health Index Formula that was developed and used for NPEI Underground Cables. The Health Index equation is shown in Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

7.1.1 Condition and Sub-Condition Parameters

Table 7-1 Condition Parameters and Weights

Condition Parameter			Sub-Condition Parameter			
m	**CP Name**	**Weight of Condition Parameter [WCP]**	**n**	**CPF Name**	**Weight of Condition Parameter Factor [WCPF]**	**Lookup Table**
1	Service Record	1	1	Age	1	Figure 7-1

7.1.2 Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Underground Cables exponentially increases with age and that the failure rate equation is as follows:

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

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

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

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for this asset are 20% and 90% respectively results in the failure and survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for Unjacketed Non-TR XLPE is also shown in the figure below:

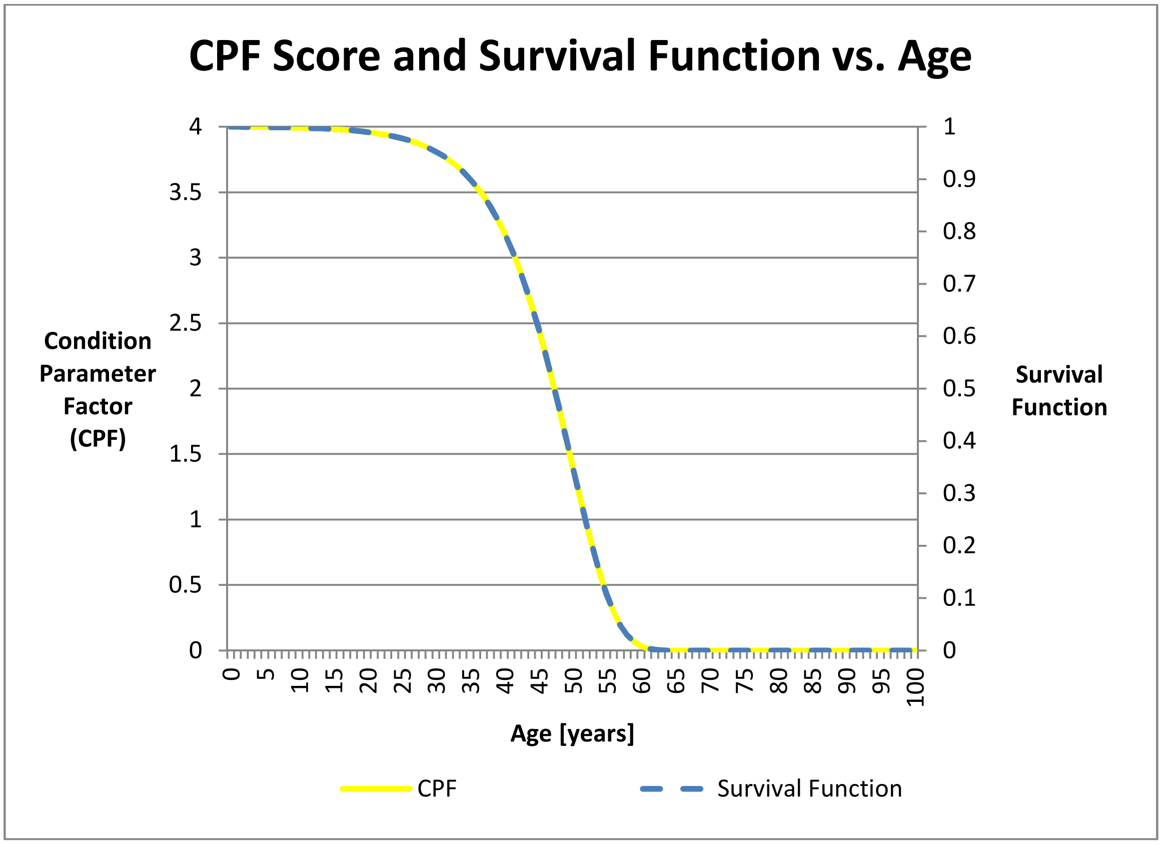

Figure 7-1 Underground Cables Age Condition Criteria

7.2 Age Distribution

<u>Main Feeders</u>

The age distribution is shown in the figure below. Age was available for 69% of all Main Feeder cables. The average age was found to be 10 years/conductor-km.

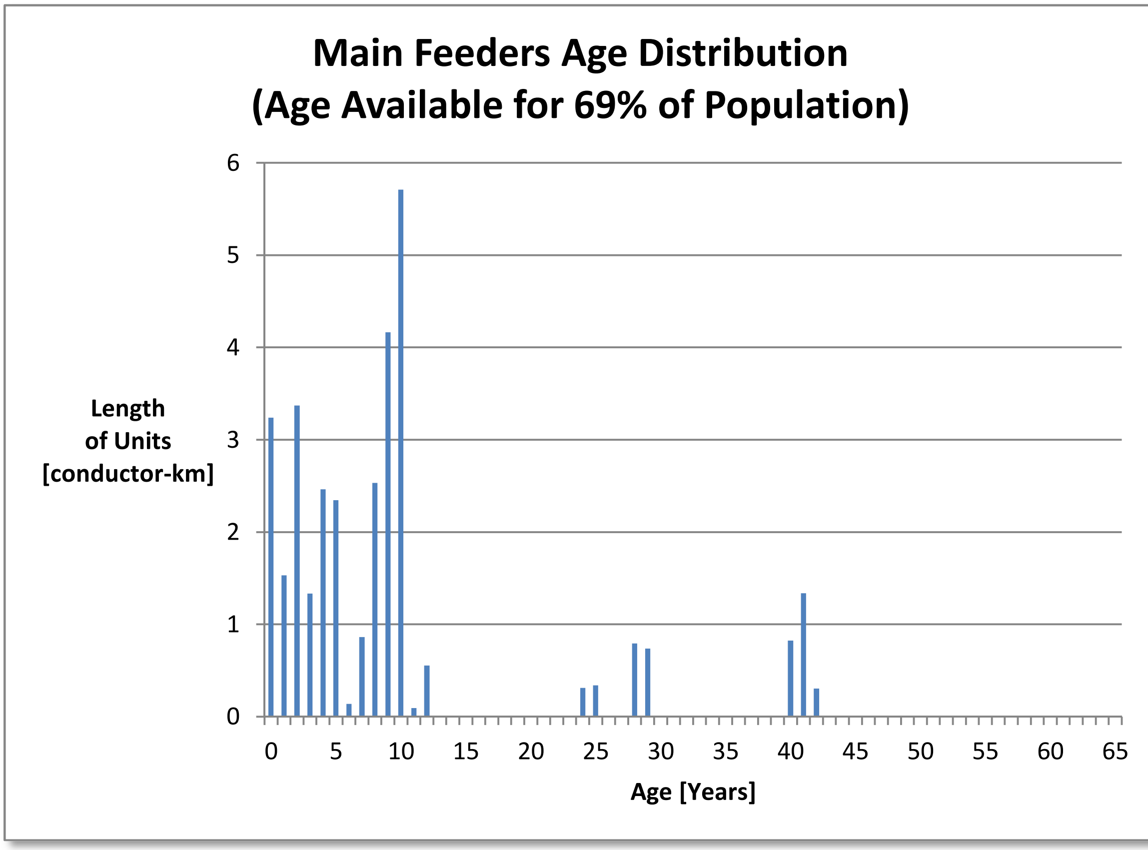

Figure 7-2 Main Feeders Underground Cables Age Distribution

<u>Distribution</u>

The age distribution is shown in the figure below. Age was available for 66% of all Distribution cables. The average age was found to be 16 years/conductor km.

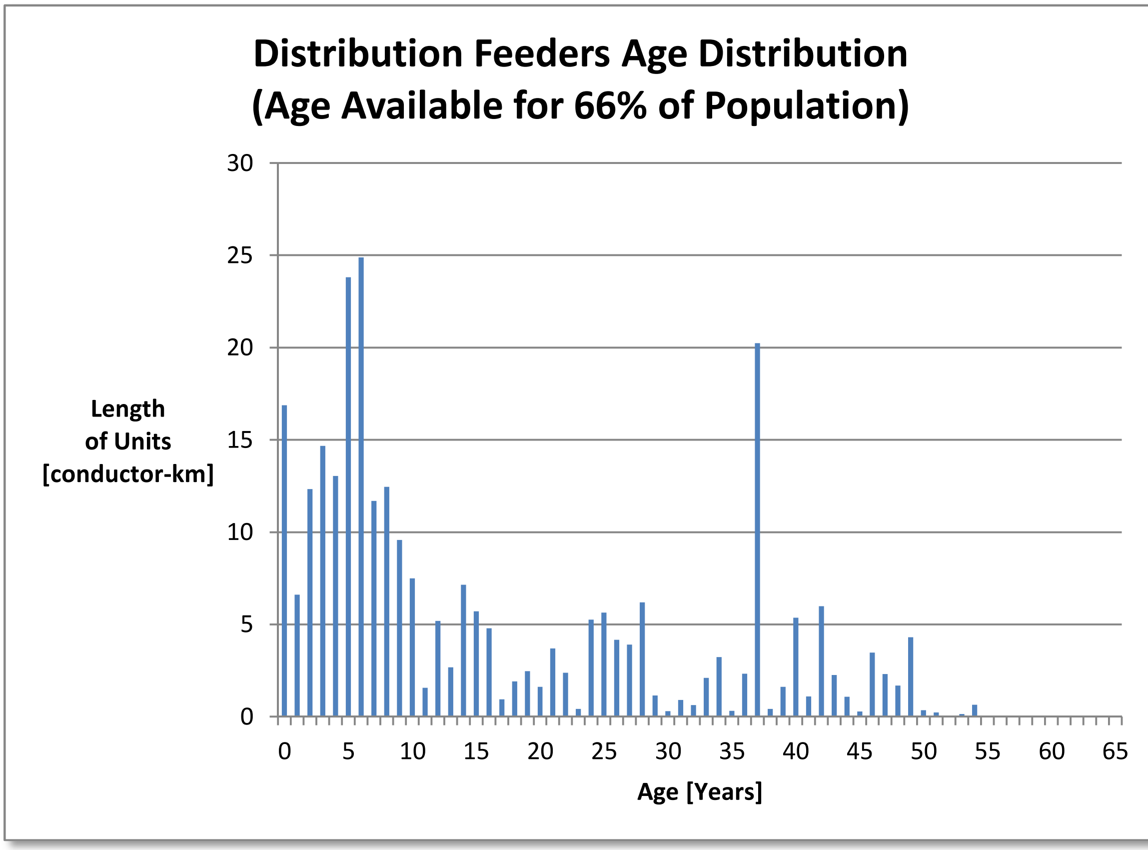

Figure 7-3 Distribution Underground Cables Age Distribution

7.3 Health Index Results

Main Feeders

There are 48 conductor-km of Main Feeder Underground Cables at NPEI. Of these, 33 conductor-km had sufficient data for Health Indexing.

The average Health Index for this asset group is 98% per conductor-km. None were found to be in poor or very poor condition.

The Health Index Results are as follows:

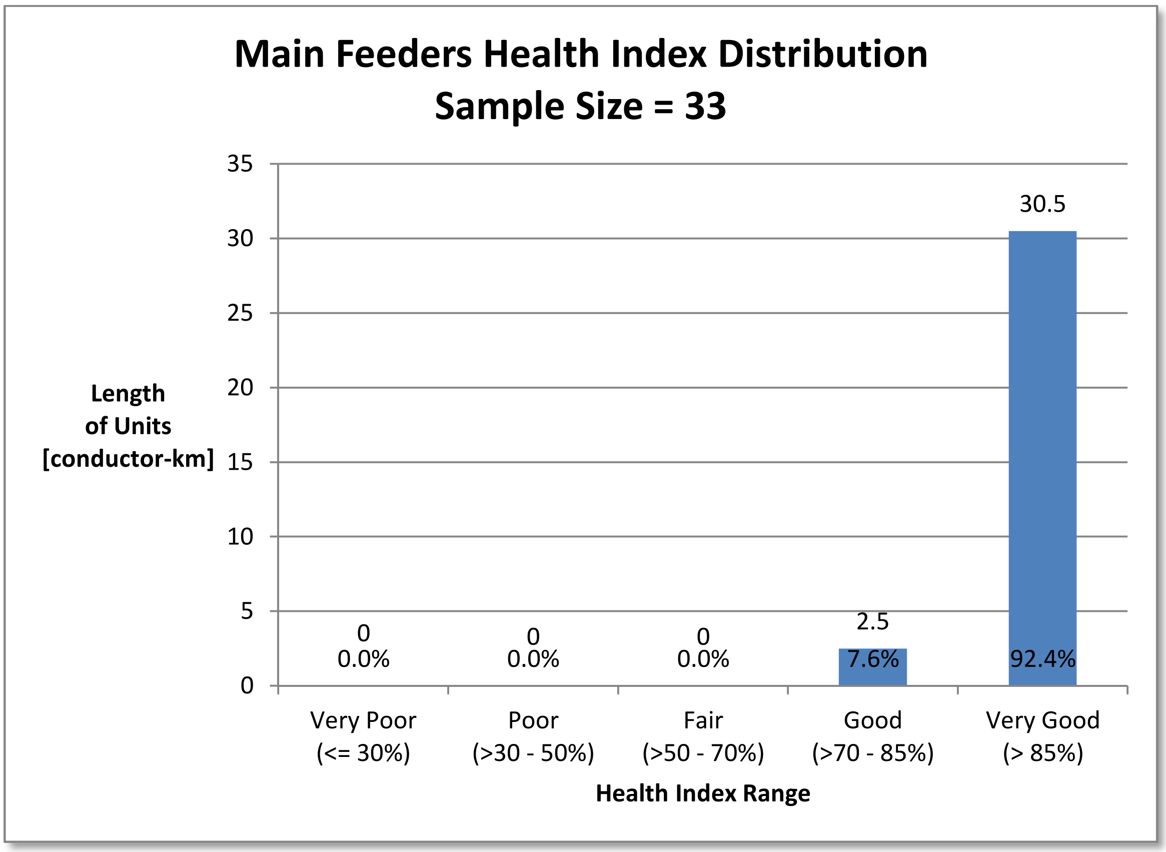

Figure 7-4 Main Feeder Underground Cables Health Index Distribution (Conductor-km)

<u>Distribution</u>

There are 427 conductor-km of Distribution Underground Cables at NPEI. Of these, 282 conductor-km had sufficient data for Health Indexing.

The average Health Index for this asset group is 94% per conductor-km. Approximately 3% were found to be in poor to very poor condition.

The Health Index Results are as follows:

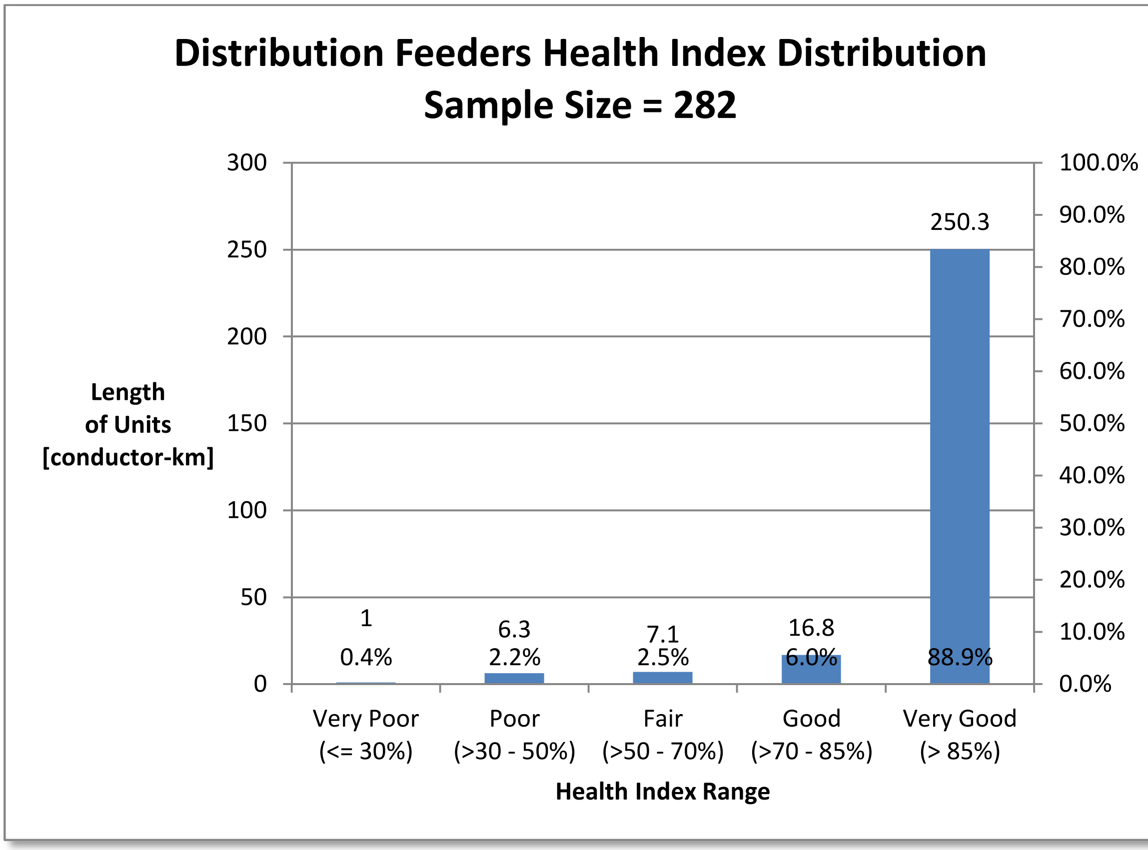

Figure 7-5 Distribution Underground Cables Health Index Distribution (Conductor-km)

7.4 Condition-Based Flagged for Action Plan

Although Underground Cables are proactively addressed, the number of units flagged for action per year is estimated using the asset failure rate f(t).

<u>Main Feeder</u>

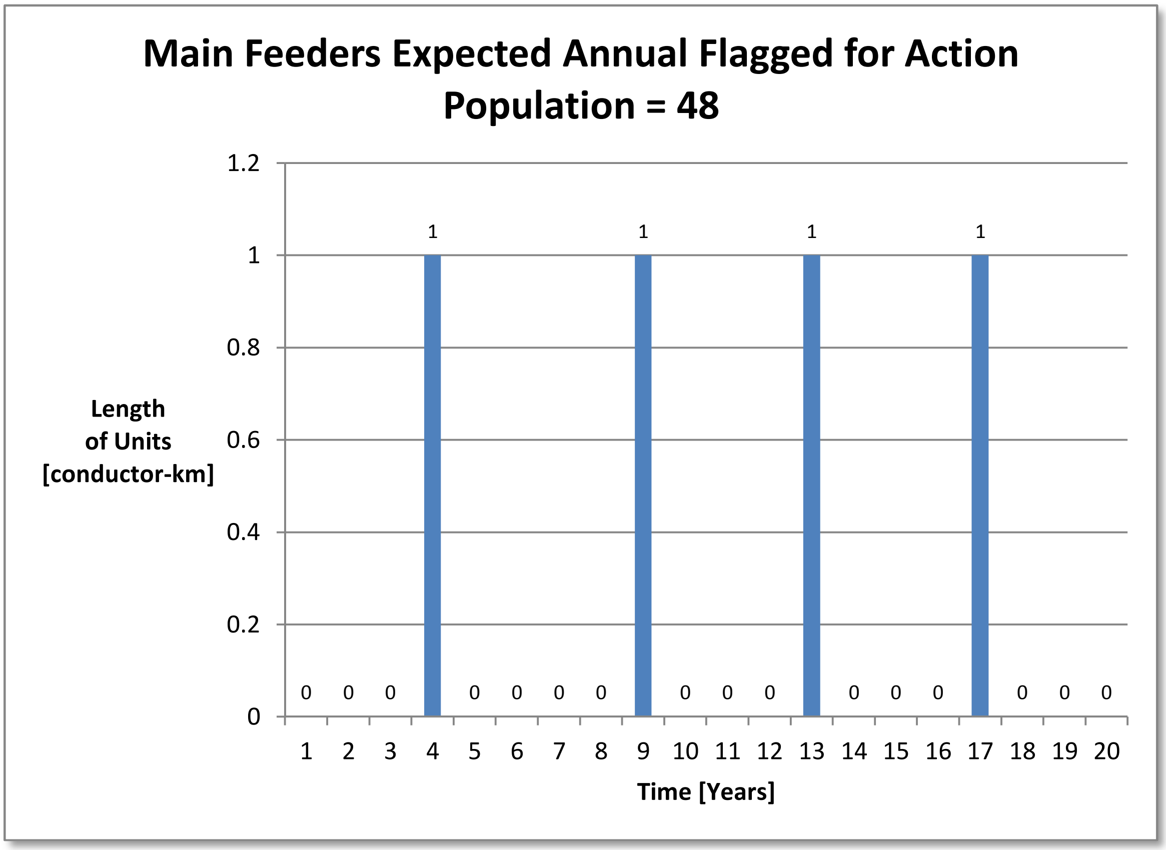

Figure 7-6 Main Feeder Underground Cables Flagged for Action Plan

Because the projected action plan is fairly steady, levelization is not required.

<u>Distribution</u>

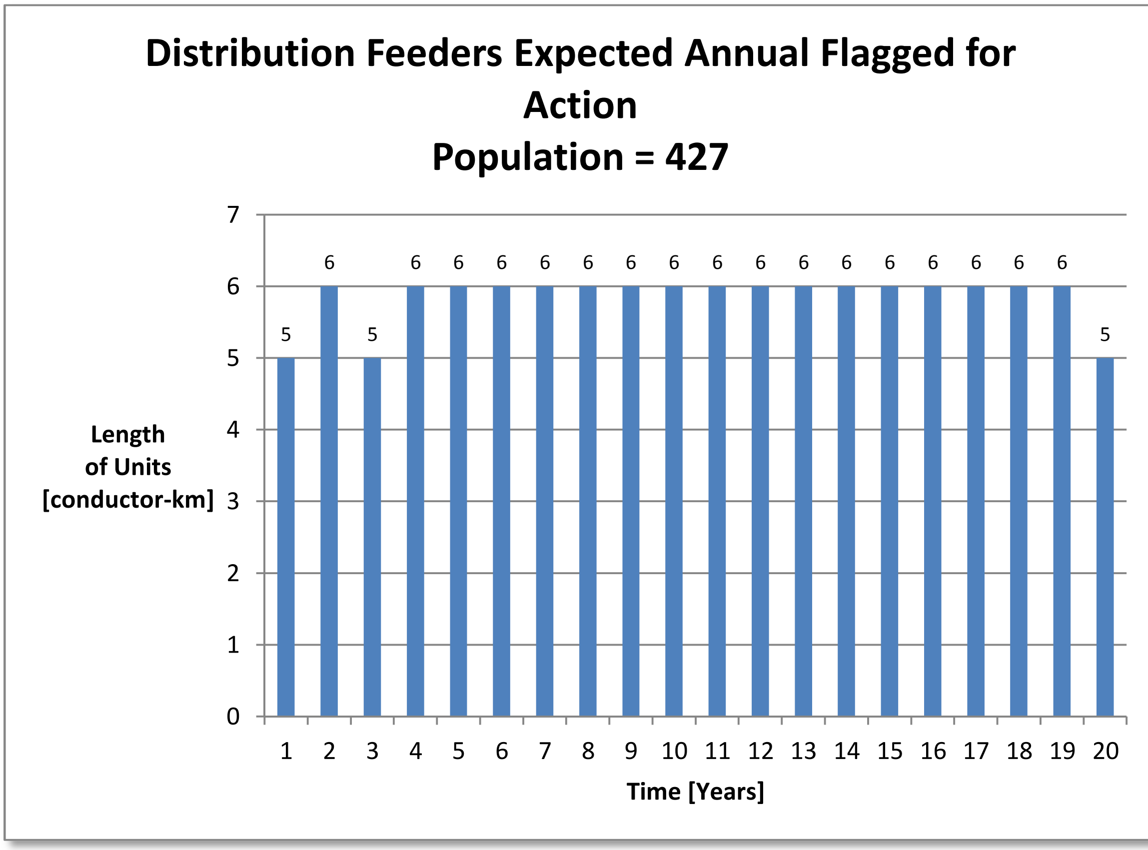

Figure 7-7 Distribution Underground Cables Flagged for Action Plan

Because the projected action plan is fairly steady, levelization is not required.

7.5 Data Analysis

Only age was available for Underground Cables.

7.5.1 Data Gaps

Although visual inspections and ultrasonic and infrared scans are conducted for Underground Cables, such data has yet to be incorporated into the Health Index. Specific and additional data that would improve the Health Index are as follows:

<table>
<tr><th>Data Gap (Sub-Condition Parameter)</th><th>Parent Condition Parameter</th><th>Priority</th><th>Object or Component Addressed</th><th>Description</th><th>Source of Data</th></tr>
<tr><td rowspan="5">Splice & Termination</td><td rowspan="5">Physical Condition</td><td rowspan="5">☆☆</td><td rowspan="3">Cable splice</td><td>Under/over-compressed connector</td><td rowspan="5">On-site visual inspection</td></tr>
<tr><td>Improper ground connection</td></tr>
<tr><td>Loose bolt</td></tr>
<tr><td rowspan="2">Cable termination</td><td>Sealing issue</td></tr>
<tr><td>Insulation erosion</td></tr>
<tr><td>Test Data</td><td>Testing</td><td>☆☆☆</td><td>Cable segment</td><td>Test Methods: insulation resistance, AC withstand, partial discharge, dielectric loss, time domain reflectometry</td><td>Field Testing</td></tr>
</table>

7.5.2 Data Availability Distribution

Main Feeder

Most of the segments had age records. As such, the average DAI for Main Feeder Underground Cables, as measured against the existing data set, is 69%.

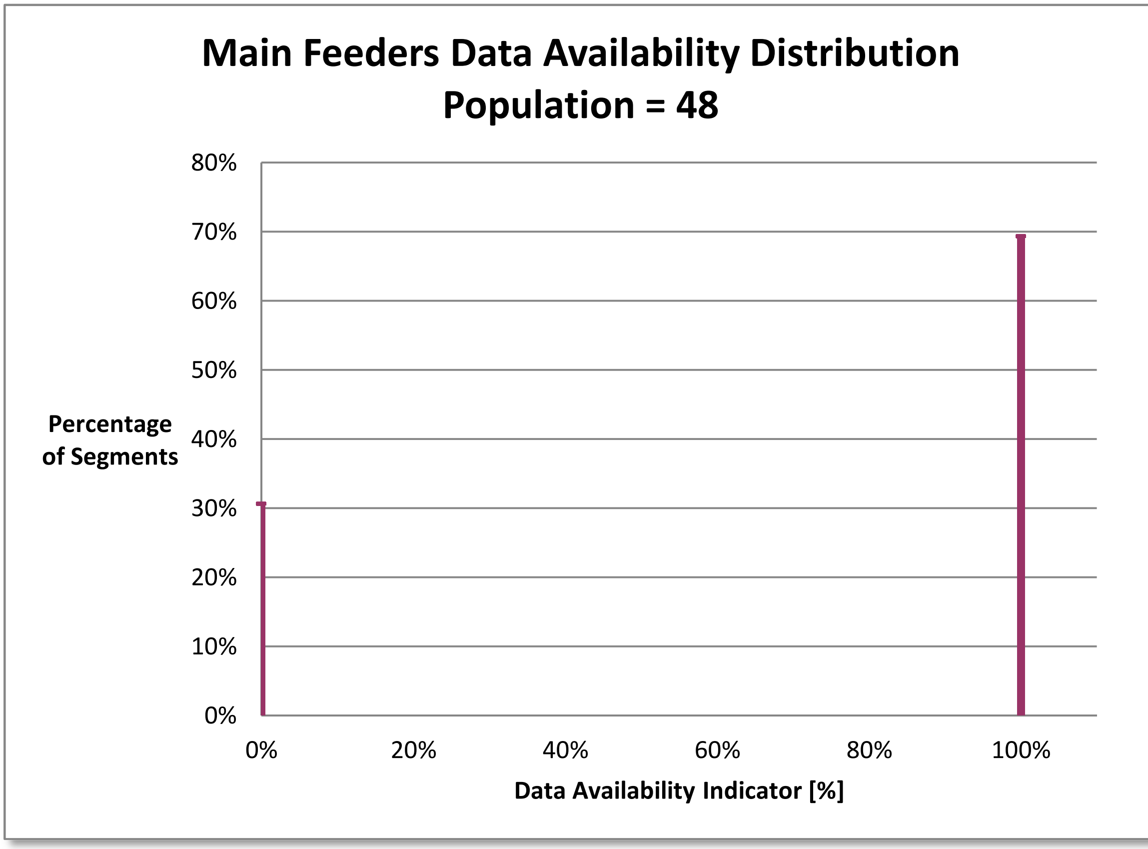

Figure 7-8 Main Feeder Underground Cables Data Availability Distribution

<u>Distribution</u>

Most of the segments had age records. As such, the average DAI for Distribution Underground Cables, as measured against the existing data set, is 66%.

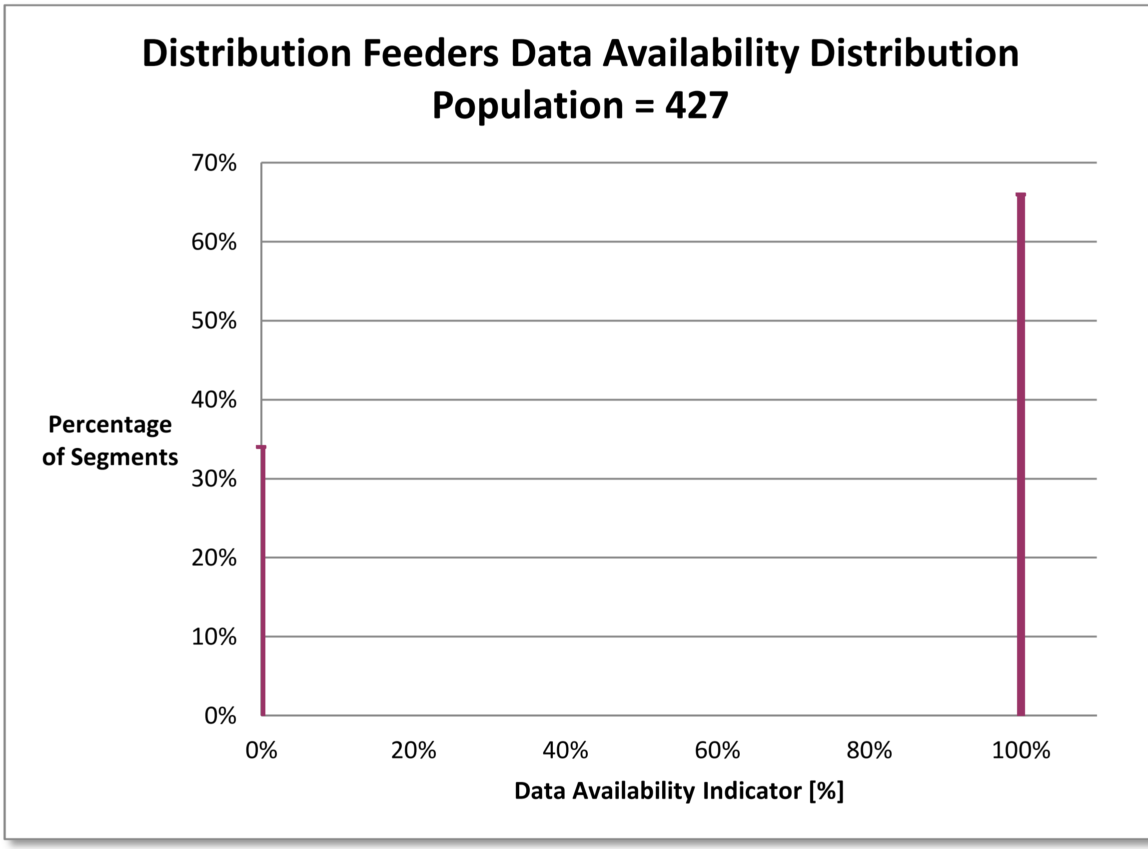

Figure 7-9 Distribution Underground Cables Data Availability Distribution

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APPENDIX F

NPEI Fleet Sustainment

Currently NPEI has a fleet of 61 vehicles that range in age from 1992 to 2013. Of the 61 vehicles 37 are greater than 3 tons and 24 are less than 3 tons. Currently, only one small vehicle is older than eight years and five large vehicles are greater than 15 years.

NPEI uses a vehicle condition scoring system which assigns each vehicle in NPEI's fleet a condition score based on a number of factors. Each vehicle's score is updated annually. Those vehicles with the lowest score are targeted for replacement first.

The scoring factors include:

- Vehicle age
- Mileage
- Engine hours
- PTO ("Power Take Off") hours
- Chassis condition
- Body condition
- Boom condition
- Technical assessment

The Table below provides details of the vehicles that NPEI plans to replace from 2015 to 2019.

Planned Vehicle Replacements - 2015 to 2019

Replacement Year	Size	Vehicle #	Purchase Year	Year Should be	Variance	Condition Rating	Area	Type	Description	Replace Cost	Total by year
2015	Other								500 kVa Portable Generator	175,000	
2015	Large	28	2003	2018	3	19	NF	Bucket Truck	Freightliner - FL70	250,000	
2015	Large	7914	2001	2016	1	-9	SV	Bucket Truck	Sterling	357,000	
2015	Small	14	2004	2014	-1	5	NF	Light Truck	Dodge 1500 4X4	35,700	
2015	Small	7922	2008	2018	3	6	SV	Light Truck	Chev 2500	35,700	853,400
2016	Other								Pole Trailer	22,000	
2016	Other								Go-Devil	135,000	
2016	Large	BH	1985	2000	-16	-5	NF	Backhoe	Backhoe	70,000	
2016	Large	4	2001	2016	0	38	NF	Bucket Truck	INTER 4900	364,140	
2016	Small	15	1995	2005	-11	4	NF	Cube Van	Ford E350	61,200	
2016	Small	7919	2004	2014	-2	6	SV	Light Truck	Ford Ranger	35,700	
2016	Small	7921	2008	2018	2	3	SV	Light Truck	Chev 2500 Diesel	35,700	
2016	Small	22	2000	2010	-6	8	NF	Van	GMC Safari	35,700	759,440
2017	Large	45	2007	2022	5	2	NF	Bucket Truck	International 4400	318,362	
2017	Large	42	2003	2018	1	13	NF	Bucket Truck	Freightliner - M2	318,362	
2017	Small	24	2005	2015	-2	0	NF	Light Truck	Ford F150 4X4	37,142	
2017	Small	7918	2004	2014	-3	1	SV	Light Truck	Ford Ranger	37,142	
2017	Small	7920	2006	2016	-1	-2	SV	Van	GMC Savana	37,142	748,152
2018	Other								Pole Trailer	22,000	
2018	Large	33	1993	2008	-10	23	SV	RBD	INTER 4900 (SPARE)	441,632	
2018	Small	27	2006	2016	-2	-6	NF	Light Truck	Ram 1500 4x4	37,885	
2018	Small	52	2009	2019	1	0	NF	Light Truck	Ford F250 4X4	37,885	
2018	Small	47	2007	2017	-1	3	NF	Van	GMC Savana Pro	33,122	
2018	Small	48	2007	2017	-1	5	NF	Van	GMC Savana Pro	33,122	605,647
2019	Large	9	1992	2007	-12	-24	NF	RBD	INTER 4900 (SPARE)	450,465	
2019	Small	7923	2008	2018	-1	-27	SV	Light Truck	GMC 1500	38,643	
2019	Small	46	2007	2017	-2	8	NF	Light Truck	2500 Sierra	38,643	527,751
										3,494,390	3,494,390
# Years											**5**
Average per year											**698,878**

APPENDIX G

NPEI Customer Engagement Plan

NPEI Customer Engagement Plan

Date: July 31, 2014

Submitted to:
Niagara Peninsula Energy Inc.

Submitted by:
ICF International
808-277 Wellington Street West, Suite
Toronto. Ontario M5V 3E4 Canada

Table of Contents

1 Introduction

In October of 2012, the Ontario Energy Board (OEB/Board), set new policy for distribution system network planning in Ontario, requiring electricity distributors to take a comprehensive and integrated approach to planning. The OEB put forth how distributors are to accomplish this planning in a recently released Board Report (Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements, March 28, 2013, referred to hereon as Chapter 5), which describes in detail how the distributor is to prepare the Distribution System Plan (DSP) and what the plan is to contain.

In particular, electricity distributors are required to meet the OEB Customer Focus Outcome by demonstrating that the distributor has responded to identified customer preferences (e.g. Conservation and Demand Management {CDM}, distributed generation, load management, access to energy data, and expectations during outages). Customer engagement is essential to achieving the Customer Focus Outcome. Distributors need to know which services are valued by their customers. These new requirements have the following implications on how distributors consult with their customers:

- The level of scrutiny imposed by the OEB on distributors with regard to how they consult with their customers and react to feedback has been increased.
- In turn, distributors are expected to document all customer engagement work more extensively than they have in the past, and, in particular, are to demonstrate how customers' views, needs, preferences and priorities are accounted for in the DSP and their distribution system operations.
- More consultation and surveying work of customers is required from distributors, although the exact nature of the new survey methods expected by the OEB is still to be determined.
- Distributors are to address customer engagement in an integrated manner both at the distribution system (DS) planning stage, when delivering the engagement activities, and when interpreting customers' feedback.
- Just as in any other aspects of DS planning, distributors should subject their customer engagement work to continuous improvement by establishing performance metrics, a feedback loop and then by making course corrections and showing progress on a year-to-year basis.

Since the DSP must serve present and future customers, customer engagement will provide support for identifying current customer needs/preferences/priorities (e.g. CDM, renewables connection, load management, storage, access to customer consumption data, and customer information needs related to understanding electricity bills) and forecasting future ones.

The purposes of this document, NPEI's Customer Engagement Plan, is to:

- Layout the overarching customer engagement strategy that NPEI intends to follow, starting from the filing of its DSP, and until the next DSP filing.
- Provide a high-level overview of the customer engagement activities (information, customer education and consultation) that are planned over the course of the two year customer engagement plan planning horizon.

NPEI retained ICF International to prepare a customer engagement strategy and plan under the direction of a cross-departmental steering committee. This document is the culmination of that work. It contains a 5-year strategy and a 2-year engagement plan, which is to be updated on a yearly basis, showing two years ahead as a sliding window.

The Customer Engagement Plan document is divided as follows:

- Section 2 – 2014-2018 Customer Engagement Strategy
    - 2.1 Compliance Framework
    - 2.2 Governance Framework
    - 2.3 Documentation, Reporting and Planning Cycle
- Section 3 – 2014-2015 Customer Engagement Plan
    - 3.1 Education and Information to Customers
    - 3.2 Customer Consultation Work
    - 3.3 Service-Territory Stakeholders Consultation Work
    - 3.4 Participation in Consultation with the OPA and HONI
    - 3.5 Consultation Topics
    - 3.6 Deliverables, Milestones and Timeline

2 2014-2018 Customer Engagement Strategy

The Five-Year Customer Engagement Strategy is a description of the approach for customer engagement that both demonstrates compliance with the OEB's new customer engagement requirements and related Customer Focus Outcome, and that aligns with NPEI's corporate Vision and Mission. The Customer Engagement Strategy is a standing framework that will be followed until updated in time for the next DSP filing.

The Engagement Strategy is divided as follows:

- Section 2.1 Compliance Framework – Describes the compliance framework and the implications regarding Chapter 5 requirements.
- Section 2.2 Governance Framework – Describes responsibility for customer engagement and integration of engagement into the DS planning and the DSP.
- Section 2.3 Documentation, Reporting and Planning Cycle – Describes how customer engagement work is to be planned, executed, documented, and reported on to achieve continuous improvement.

2.1 Compliance Framework

The OEB has defined the Customer Focus Outcome for distributors as: *services provided in a manner that responds to identified customer preferences*.

As such, the three specific goals of the five-year Customer Engagement Strategy are:

Exhibit 1 Goals of the Customer Engagement Strategy

Goal 1	Goal 2	Goal 3
• Contribute to Achievement of Customer Focus Outcome	• Provide a Framework to Meet Chapter 5 Engagement Requirements	• Develop Principles to Guide Customer Engagement Plan

Exhibit 2 describes the framework NPEI intends to use to guide its customer engagement planning and implementation.

Exhibit 2 Customer Engagement Compliance Framework

Principles of Customer Engagement	Strategic Engagement Plan Response	Engagement Outcome
Take an integrated approach to customer engagement	Leverage existing points of customer contact for broader based information gathering	Efficient engagement; minimal customer fatigue
	Implement broad based customer inquiry	Investigate DS , smart grid, renewables, storage, CDM, regional, other needs
	Involve utility staff across departments in engagement plan	Inquiry covers key aspects of DS planning
		Coordinated, effective planning and plan
Take a long term perspective	Apply principles over 5-year period of DSP	Consistent inquiry strategy over DSP planning horizon
Participate in regional planning	Engage customers in any regional planning processes, as appropriate	Customers understand and have opportunity for input into broader planning context
Serve present and future customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Solid basis for monitoring and tracking trends
		Demonstration that customer needs/preferences/priorities are served by DSP
Align utility interest with customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Understanding of customer needs/preferences/ priorities
		Integration of customer needs/preferences/priorities in DS planning and Plan
Provide information on engagement opportunities	Provide meaningful opportunities for engagement	Increase in perception of customers that they are being consulted and their views are being addressed
Measure engagement performance	Identify and track engagement performance metrics	Solid basis for monitoring and tracking trends
Achieve continuous improvement in engagement	Assess engagement performance at key intervals and make adjustments, as appropriate	Increase in representativeness of consultation and number of participants
		Increase in the perception of customers that they are being consulted, and that their views are being addressed

Principles of Customer Engagement	Strategic Engagement Plan Response	Engagement Outcome
		Increase in satisfaction of participants in consultation, including consultation format and media used Increase in the level of relevance or usability of the consultation outputs
Carry out engagement consistent with corporate Mission/Values/ Vision	Engage customers with integrity, fairness, responsibility respect, transparency and provide best possible service	Customer engagement meets same standard of excellence as other utility activities
Carry out engagement consistent with Conditions of Service and any relevant corporate policies	Review Conditions of Service and relevant corporate policies in Plan development/ delivery	Consistent approach to customer engagement

The strategic engagement responses, which will feed directly into the Customer Engagement Plan, flow directly from the guiding principles and are consistent with NPEI's corporate Mission, Vision, and Values. The guiding principles are based on OEB Chapter 5 requirements and the need for customer engagement to contribute positively toward NPEI's achievement and demonstration of the Customer Focus Outcome.

For each of the engagement outcomes listed here, one or more performance metrics have been identified for tracking through the year to measure performance and show improvement. The full matrix, including suggested performance metrics, is provided in Appendix B.

2.2 Governance Framework

The Customer Engagement Strategy is designed to enable NPEI to coordinate a wide array of engagement activities in an integrated fashion across departments; analyze, document and interpret the results; make DS decisions on the basis of these results more effectively; and then subject NPEI's customer engagement work to performance management, review, and then improvement year to year.

NPEI has created a Customer Engagement Steering Committee to orient, oversee as necessary, and integrate all customer engagement work done by Customer Services and IT, Operations, Engineering, Finance, and Conservation and Demand Management (CDM). Members of the Committee will also review the feedbacks and market intelligence being collected, convey it to their own team/department, decide whether and how the feedback needs to be acted on, and bring back the decisions made and report the resulting actions to the Committee for effective documentation of NPEI's progress toward the Customer Focus Outcome.

The Steering Committee is composed of:

- Chief Conservation Officer
- President and CEO
- Vice President, Customer Services & IT
- Vice President, Engineering
- Vice President, Finance
- Vice President, Operations

The Committee will have a Coordinator, who is responsible for preparing, facilitating and taking minutes. The Committee will meet on a quarterly basis. Meeting preparation will consist of collecting and gathering all preliminary consultation results. All Committee members will be responsible for launching (in some cases) and implementing operations activities that reside in their respective areas of responsibility, synthesizing early engagement results, bringing to the attention of other Committee members any issues that require resolution, and then acting on the resolution within their areas of responsibility.

The Coordinator will be responsible for coordinating the finalization of the NPEI Engagement Plan for 2014-2015, the drafting of the Customer Engagement Baseline Report, the drafting of the Year-End Report, and then the updating of the two-year Customer Engagement Plan on an annual basis. The definition of the aforementioned reports will be provided in Section 2.3. The Coordinator will be responsible for these documents to be completed, but will rely on all other Committee members and their respective teams to contribute with data, analysis, decisions and write-ups.

The Steering Committee will preside over and operationalize the establishment and the monitoring of customer engagement performance metrics as detailed in the Compliance Matrix shown in Appendix A. The Steering Committee will review these metrics and make decisions on any improvements to customer engagement year to year as measured by these metrics. The review will be documented in the Year-End Customer Engagement Reports, on an annual basis.

2.3 Reporting and Planning Cycle

The Customer Engagement framework at the core of NPEI's Engagement Strategy is a structure that will be sustainable, self-correcting, and self-improving. The Steering Committee will meet quarterly to discuss any issues that might arise during consultation and will enact a formal annual review--action--adaptation cycle documented through the following key documents, which will be updated on a regular basis:

- The **2014-2018 Five-Year Customer Engagement Strategy** The first five-year Customer Engagement Strategy will be filed with the DSP in August 2014, and will be reviewed and updated as needed every 5 years.
- The **2014-2015 Two-Year Customer Engagement Plan,** will be filed with the DSP in August 2014, and will be updated on an annual basis.
- The **2014 Customer Engagement Baseline Report** will be filed with the DSP in August 2014. The Baseline Report will provide a detailed description of NPEI's current customer engagement activities, and any conclusions, recommendations and actions planned as a result of the consultation.

- The **Customer Engagement Year-End Reports** are expected to be completed by March of each year, starting in 2015, based on data agglomerated in December of the year before. The first Year-End Report will be an update of the Baseline Report, and subsequent Year-End Reports will be an update of the report from the previous year. The content will be similar to that of the Baseline Report, but will highlight any evolution in customer needs, preferences, and priorities, and any new decisions and actions made to improve service and contribute to the achievement of the Customer Focus Outcome.

- The **Two-Year Customer Engagement Plans** are expected to be completed in March of each year, starting in 2015. Each plan will contemplate all engagement activities to be planned in the next two years. Each plan will also be an update of the plan from the prior year. The plan will focus on the activities and timeline for the two year planning horizon. The selected activities, the approach to deliver the engagement work, and the planning should be improved each year based on lessons learned from the previous years.

- The **Next Five-Year Customer Engagement Strategy** will be an adaptation/improvement from that of 2014-2018. It will be filed with the next DSP.

This reporting work is key to the integration of the customer engagement work. The reports will document findings, observations and conclusions across all of the associated engagement activities, on a yearly basis and in a concise fashion. This reporting, then review and discussion of the reports by the Steering Committee, will help to ensure that each department/team involved in, or in need of feedback and insights coming from customer engagement, will look transversally across departments and make decisions to the benefit of, and thereby enhance, the value proposition for customers.

2.3.1 Improved Documentation Practices

The reports and reporting described in Section 2.3 will improve the documentation practices of NPEI regarding customer engagement and its integration into DS planning and the DS Plan.

Regarding the coordination of infrastructure planning with customers or other third parties, the Board requires distributors to provide:

> *"…A distributor must provide […] a description of the consultation(s), including*
>
> - *the purpose of the consultation (e.g. Regional Planning Process);*
> - *whether the distributor initiated the consultation or was invited to participate in it;*
> - *the other participants in the consultation process (e.g. customers; transmitter; OPA);*
> - *the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and*
> - *an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how." (Section 5.2.2 Coordinated planning with third parties. Chapter 5.)*

In order to improve the consistency in NPEI's documentation of consultation work, and to comply with the OEB's coordination requirement, NPEI's IT personnel will utilize the electronic filing system to enhance the traceability and searchability of customer engagement documents across departments.

NPEI will also create a standard consultation activity form, the Chapter-5 Consultation Form or C5C Form, which will be used by NPEI staff to document consultation activities that result directly from the Customer Engagement Plan. The C5C form is shown in Appendix D.

The Form will contain fields to:

- document the purpose of the consultation activity,
- provide a brief description of the consultation activity,
- indicate whether the distributor initiated the consultation activity or was invited to participate in it,
- describe the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation, and
- provide an indication of whether the consultation is expected to affect NPEI's DSP.

The impact, if any on the DSP, will be addressed by the DS planners and documented as part of the review and updating of the DSP.

The C5C Form will be populated and stored along-side any related consultation deliverables (e.g. meeting minutes, survey result tables, interview notes, etc.). The C5C Form will be used to document major consultation events such as CDM events, participation in regional planning activities, customer engagement interviews, focus group sessions, and regular meetings with municipalities. Since this is a new tool, its use will evolve as NPEI gains experience with it over the two-year Customer Engagement Plan.

3 2014-2015 Customer Engagement Plan

The 2014-2015 Customer Engagement Plan is NPEI's work plan to deliver customer engagement until the end of 2015. The Engagement Plan will be updated on a yearly basis in the spirit of continuous improvement, and to keep the plan current.

This Engagement Plan is divided as follows:

- **Section 3.1 Education and Information to Customers** – High-level description of the work that NPEI will carry out to educate and inform its customers about important topic areas related to electricity distribution.
- **Section 3.2 Customer Consultation Work** – High-level description of consultation activities that NPEI will carry out to obtain feedback from its customers and from key stakeholders on matters related to electricity distribution.
- **Section 3.3 Service-Territory Stakeholder Consultation Work** – High-level description of consultation activities that NPEI will carry out to obtain feedback from indirect customers, that is, service providers and/or key stakeholders in its service territory.
- **Section 3.4 Participation in Consultation with the OPA and HONI** – Actions in response to prescriptive requirements about whether and how NPEI should participate in consultation with the OPA and HONI.
- **Section 3.5 Consultation Topics** – Introduction, description and purpose of the list of consultation topics, how the list should be used, and when the list should be created, updated and revisited.
- **Section 3.6 Deliverables, Milestones and Timeline** – Milestones, deliverables and schedule of customer engagement through to the end of December 2015.

3.1 Education and Information to Customers

Providing education and information to customers on distribution system matters is an important component of achieving the Customer Focus Outcome. NPEI will achieve this through the use of an extensive array of media, which may include: its call center and customer service representatives (representatives), its website, direct mail, direct call, bill insert and/or e-bills, social media, local radio broadcasting, local press, and its CDM professionals.

NPEI's Customer Engagement Plan will provide:

- Confirmation of whether customers are being properly informed and educated about certain topic areas of importance.
- Information on NPEI's work on communications to demonstrate that NPEI is improving how it is informing and educating its customers about important topic areas.

The Customer Engagement Baseline Report will document the customer education and information activities that NPEI currently carries out. NPEI will update these descriptions on an annual basis, highlighting any improvements made, and these descriptions will form part of the Year-End reports.

The initial documentation will describe, but not be limited to:

- **Call Center Tracking:** The current tools and interface for handling, categorizing, tracking, assessing and addressing customer inquiries and complaints.
- **Outages and First Responses:** The current tools and procedures related with outages and first responses. The description may include the use of IT systems, information channels, department involved, protocols and typical sequence of action. For example, the communication channels might include: information on outages on the website, social media if any, and/or local radio broadcast, as applicable.
- **Capital Improvement Projects and Construction Work:** The triggers, frequency, nature of information and the communication channels. This may include information on incoming projects on the NPEI website. It may also include any information letters on potential disturbances (direct mail), local radio broadcast links, and publications in the local press.
- **Renewable Energy Generation (REG) Opportunities, Programs, Modalities and Connection Procedures:** Information on REG connection on NPEI's website, the representative's procedures when he or she receives a call about REG, the REG-connection information package sent to customers upon request, and information regarding the full-time engineering technician providing technical assistance to customers.
- **Approach to Providing Access to Energy Data to Customers**: The current tools and interface for access in electronic format, real time data access, and actions to date to provide customers with the ability to make decisions affecting electricity costs. It will include a description of myAccount, and related representative and customer interface and assistance, and the provision of 15-minute interval data when applicable. The feedback received to date on the myAccount platform, and then the implications, decisions made, and changes made to date to improve data access and the myAccount platform accordingly, may be included.
- **Customer Education on Electricity Bills and Price:** A description of how NPEI informs customers about rates issues, electricity bills, rate structure, time-of-use, electricity retailers, regulated price plan, market prices, weather normalization, and reasons causing rates to increase and other matters as they emerge over time. It will include a description of the process through which the representatives make use of myAccount to handle customer inquiries/complaints/comments related to their electricity bills and prices, including showing customers their energy data, and then using the energy data and the myAccount tool to educate these customers about their energy bills, how to control their energy use and, in turn, manage their energy expenses.
- **CDM Engagement Actions:** A high level summary description of the direct customer engagement work done by NPEI's CDM personnel, roving energy manager, and delivery agents, as well as a high level description of mass-market communications media used to advertise its OPA-contracted province-wide CDM programs.
- **Electricity Storage:** Description of information about the new energy storage activities province-wide and locally.

3.2 Customer Consultation Work

NPEI will continue its ongoing work in customer consultation and will also implement the following enhancements:

- Bolster its tracking of customer feedback (i.e., tracking of questions and inquiries and the transactional survey); and

- Launch new activities to obtain more comprehensive customer feedback (i.e., site visits, and customer satisfaction phone/on-line based survey).

In addition to adding and strengthening communication channels as per above, NPEI also plans to:

- Improve how NPEI documents consultation results through populating and storing the C5C form alongside survey data tables, meeting minutes and interview notes, as noted in Section 2.3 of the Customer Engagement Strategy.

- Improve how NPEI integrates consultations results across departments, acts on feedback and customer views, needs, preferences and priorities, across departments; and addresses these through the cross-departmental Steering Committee; and a feedback loop instituted through annual customer engagement reporting and planning activities, as noted in Section 2.3 of the Customer Engagement Strategy.

The existing and new customer consultation activities that NPEI intends to deliver during the 2014-2015 period include:

- **CDM Market Characterization Site Visits:** As part of its endeavours to meet its CDM targets for 2014, NPEI will carry out some market characterization work, focusing on particular key market segments that have a high achievable potential for savings and may be able to contribute to the savings targets. As part of this work, NPEI will carry out site visits of commercial and industrial facilities in market segments of interest. This consultation is expected to take place in July-September 2014. NPEI chose to carry out site visits to collect baseline information about energy intensive systems in particular market segments, and to avoid self-reporting biases and error that would occur with phone interviews. NPEI has retained ICF International to conduct this market characterization work.

- **Call-Center Tracking of Customers' Inquiries, Complaints & Feedbacks with Implications on DS Planning:** NPEI will bolster its practice and procedures surrounding the tracking of comments, inquiries and complaints. NPEI currently conducts call-type analysis on a monthly basis, the result of which is already shared with the OEB. NPEI's representatives register every inbound or outbound call in its Customer Integrated System (CIS), assigning one or a few specific labels for each of them related with the topic area. NPEI can breakdown call volume by location and topic. NPEI already tracks calls on outages (during and after), high energy bills, payment arrangement, energy data access platform(s), CDM (and each of the programs), REG, as well as capital improvement projects and construction work.

  NPEI's Vice President of Customer Services and IT reviews the call feedback on a monthly basis, identifies and assesses any trends, and makes adjustments to the call centre process as needed. In particular, if and when new "types" of comments are being recorded by the representatives, this would show in the monthly call analysis, a new label would thereby be created and subsequently monitored. This mechanism guarantees legacy trends are monitored, and new trends are identified swiftly. For example, energy storage has not been recorded as a topic area to date. If it were to become a recurring call in the "miscellaneous" category, it would quickly become a call category on its own and be tracked diligently.

  NPEI plans on improving its use of the call tracking by making enhancements to: planning, organizing and integrating the labels, comparing results against that of other consultation activities across departments, decision-making and taking actions across departments, and documenting planning, feedback and review.

- **Call-Center Transactional Survey:** NPEI's representatives deliver transactional-survey questions, as part of their regular call script. The call scripts are changed based on trends of call types and feedback from representatives. NPEI will use its CIS system as well as an integrated survey tool to register the responses. Follow up calls and outgoing call scripts will be used to follow up on survey questions.

- **Customer Satisfaction Phone and/or Online Survey:** NPEI plans on launching a random customer satisfaction phone and/or online survey to reach customers who do not generally call NPEI to ask questions and provide feedback. This first survey is expected to take place in May-June 2014, and be conducted every second year. NPEI intends to use an UtilityPulse Survey. The channels used to disseminate the survey may include: customers who receive their bills electronically, NPEI's website, social media, incoming phone calls, and any email exchange with customers. NPEI will explore options for holding contests and awarding prizes, such as Energy Star appliances, to encourage participation in the survey. NPEI has had success in using such contests to drive participation through social media. NPEI's Customer Services and IT department will be responsible for the customer satisfaction survey.

A cornerstone of integration of the consultation activities is the shared list of consultation topics that NPEI will maintain as a living document. NPEI plans to update this list at least yearly, and then use the list, for example, to determine which call types are the most critical to track, what transactional survey questions to run and when, and what customer satisfaction phone survey questions to apply.

3.3 Service Territory Stakeholders Consultation Work

NPEI intends to gain additional perspective on its customer needs, priorities and preferences through maintaining and extending consultation to include key tradespeople and professionals involved in new REG connections and behind-the-meter services, as well as local and regional municipalities, and other utilities.

The existing and new service-territory stakeholder consultation activities that NPEI intends to deliver during the 2014-2015 period include:

- **CDM Market Characterization Interviews**: NPEI will consult with critical market actors in key market segments. The consultation will include CDM topics as well as other key DS planning topics, as necessary, which will complement the customer consultation being carried out. The consultation will be delivered through directed in-depth phone interviews during June through August of 2014. NPEI chose to use an adaptable explorative method, in-depth interviewing, because the group being consulted is comprised of a very heterogeneous mix of tradespeople, professionals, vendors, key accounts, trade organizations, etc. and because this group can provide meaningful market insights. NPEI has retained ICF International to conduct this market characterization work under the direction of the CDM group.

- **Regular Stakeholder Meetings (Also Known as Public Utility Committee Meetings):** NPEI has participated and will continue to participate in monthly meetings with key stakeholders such as: local municipalities and Niagara Region, Enbridge Gas Distribution, and the local cable and phone companies. NPEI will use this platform to consult about topics related to distribution system planning. NPEI may augment its documentation of these meetings through the use of the C5C Form, and also through minute-taking of one-on-one or small-committee ad-hoc meetings taking place around and as a result of the main monthly meeting. NPEI's Engineering and Operations departments are responsible for participating in these meetings.

- **Consultation with Customers' Technical Service Providers:** NPEI intends to carry out consultation with customers' technical service providers, i.e., tradespeople or professionals involved in new REG connection, new or modified load customer connections, or work on behind the meter services. NPEI intends to proceed through directed phone interviews conducted by its own staff, following interaction with the service provider on normal business activities. NPEI intends to use the information acquired through these consultations to identify requirements for focus group activities that are expected to take place on an annual basis in a central location. Both consultation activities are new, and will be rolled out in 2015. NPEI plans to do the planning for the phone interviews (e.g. questionnaire) in the spring of 2015 and hold the focus groups in November or December of 2015. NPEI's Engineering and Operations Departments will be responsible for carrying out this consultation on a regular basis.

NPEI will consolidate all service-territory stakeholders' consultation topic areas in the list of consultation topics referred to in Section 3.5. NPEI plans to use the list as a tool for bringing forward meeting agenda items for the public-utility commission meetings, and/or develop interview guides or focus-group guides.

3.4 Participation in Consultation with the OPA and HONI

In Chapter 5, the OEB has specific requirements about whether and how NPEI should participate in consultation with the OPA and HONI.

To meet these requirements, NPEI will:

- **Consult in Regional Processes:** NPEI will obtain a letter from OPA and from HONI confirming that no regional process is currently underway. NPEI may build and integrate a web page to provide information on regional processes, and populate it with the letter from the OPA and from HONI, indicating that no regional process is currently underway. NPEI will check in with the OPA and HONI on an annual basis to monitor if and when regional processes might take place, and record the results and provide the documentation in the Year-End report.
- **Consult with Regionally Interconnected Distributors, as required:** NPEI only interconnects with HONI. NPEI will send a letter to HONI advising that NPEI is preparing its DSP for filing, and identifying any potential issues and request feedback. NPEI will send a letter notifying HONI when the DSP is being finalized and indicate how any issues related to HONI have been resolved. The letters will be included in the DSP filing.
- **Consult on REG Interconnection:** NPEI will send letters to OPA and Hydro One, providing the following information in advance of its DSP filing and will include those letters in its DSP filing. The information will consist of: forecast load, forecast REG connections and any planned network investment to accommodate connections; investment involving smart grid that could have an impact on assets serving regionally connected utilities, and the results of projects or activities involving demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned over the forecast period. NPEI will follow up with OPA and HONI on any matters arising from the material sent and address/document concerns and their resolution in its DSP filing.
- **Consult on REG Investments:** NPEI does not intend to do investments related to REG during the 5 year DSP plan horizon, and thereby will send to the OPA a letter 60 days in advance of the filing of the DSP, and include the letter in the DSP filing. NPEI may prepare a response letter to the OPA letter, and if so, will file this letter with the DSP filing.

3.5 Consultation Topics

The consultation topics may cover at least the following categories:

- Power Quality and Reliability
- NPEI's Handling of Outages
- NPEI's Handling of Capital Improvement Projects and Construction Work
- REG Opportunities, Programs, Modalities and Connection Procedures
- NPEI's Approach to Providing Access to Energy Data to Customers
- Price, Billings and Payment - NPEI's Customer Education Work on Electricity Bills and Price
- Conservation and Demand Management
- Electricity Storage
- Customer Communications and Customer Service Experience

On a yearly basis, NPEI plans to organize its consultation using a central, living list of consultation topics. The list will be a repository of all research and consultation topics/issues across all consultation activities (as presented in Section 3.3 and Section 3.4). For example, the list will be used to build the site-visit protocols, add key items to retrieve from call-type analysis and as part of transactional surveying; draft research questions for the customer satisfaction phone and/or online survey; suggest agenda items for the stakeholder meetings; and develop service providers' consultation questionnaires and focus-group protocol.

As a result of using a central list of consultation topics, NPEI will be able to:

- Check the exhaustiveness of the consultation by all committee members.
- Reinforce the validity of certain critical feedback through triangulation.
- Slim down questionnaires or interview guides, while making sure all topic areas are still covered by appropriate consultation methods.
- Establish a framework and a method to develop consultation aids (i.e., questionnaires, meeting agenda, site visit protocols, etc.).
- Reduce the need for all Steering Committee members to review all consultation aids.

3.6 Deliverables, Milestones and Timeline

The 2014-2015 Customer Engagement Plan is comprised of a set of activities, specific tasks within each activity, and a timeline for completion of each activity during the 2-year planning period. Appendix C contains the Customer Engagement Matrix, which itemizes the activities and tasks, and the timeline for completion.

Appendix A – Regulatory Compliance Matrix

Chapter 5 Compliance Matrix Checklist

Chapter-5 Requirements with Regard to Engagement, and How NPEI Is Showing Compliance Through Its Engagement Plan

Provides a cross-tabulation between Chapter-5 requirements and activities, mechanisms and measures laid out in the engagement plan

Chapter-5 Requirements		Compliance Demonstration
1) Customer Engagement Policy		
1.1	Take an integrated approach to customer engagement	NPEI has established a customer engagement governance framework in the form of a 5-year customer engagement strategy document, a cross-departmental steering committee, quarterly meetings, a baseline report, annual reporting of findings, observations, conclusions and implications, engagement performance metrics, and a 2-year customer Engagement Plan that will be updated yearly based on the findings of the previous year. The details of all of the above are described in the 2-year Engagement Plan. Such planning enables NPEI to coordinate a wide array of engagement activities in an integrated fashion across departments, then analyze, document and interpret the results and make DS decisons on the basis of these results more effectively.
1.2	Align utility interest with customers	The new integrated approach to customer engagement described in 1.1, as well as the new consultation activities described in the current Engagement Plan, will yield meaningful intelligence on customers' interests and means to interpret them, which in turn will infuse NPEI's DS planning over the next 5 years.
1.3	Serve present and future customers	NPEI is commited to provide a high level of service to its present and future customers. The new integrated approach to customer engagement described in 1.1, as well as the consultation activities in the current Engagement Plan, will provide NPEI with feedback from its customers, insights about their current and future preferences, needs and priorities, and information about new trends as they arise. Such information will assist NPEI to maintain or increase the level of service, and enhance the way it serves its customers based on changing conditions such as changes in demography, the emergence and adoption of new technological options and the build up of new customer expectations.
1.4	Demonstrate that customer needs/preference/priorities are served by the DS Plan	As part of the new integrated approach to customer engagement described in 1.1, NPEI will document findings, observations and conclusions accross all of its engagement activities on a yearly basis and in a concise fashion. This feedback will be provided to the DS planners for review and integration, as appropriate, into DS planning and the DS Plan. For 2014, this feedback has been incorporated into the DS Plan filed with the Board. For intervening years until the next DS Plan, feedback will be documented and addressed in the year-end customer engagement reports on a yearly basis.
1.5	Take a long term perspective	The governance framework, as described in 1.1, was built for the long run. NPEI has established a long term strategy for customer engagement to correspond to the long term perspective of 5 years of its Distribution System Plan. To ensure the currency of its engagement plan to fulfill its engagement strategy, NPEI has developed a 2 year Engagement Plan, which will be updated annually. NPEI's governance structure for customer engagement ensures that the strategy will be revisited as part of the planning of the subsequent DSP.
1.6	Measure engagement performance	The governance framework, as described in 1.1, includes the establishment and the monitoring of customer engagement performance metrics as detailed in the Customer Engagement Plan. The customer engagement Steering Commitee will review these metrics and make decisions on any improvements to the customer engagement year to year as measured by these metrics. The review will be documented in the year-end customer engagement reports on an annual basis.
1.7	Achieve continuous improvement in engagement	The governance framework, as described in 1.1, is a structure that will be sustainable, self-correcting, and self-improving because the Steering Commitee will meet quarterly to discuss any issues that might arise during consultation and will conduct lessons-learned analyses as well as discussions surrounding the engagement performance metrics. The lessons learned and the discussions will be documented in the year-end report on an annual basis. Then on the basis of these discussions and lessons learned, NPEI will update the 2-year Engagement Plan yearly, and update the 5-year Engagement Strategy every fifth year.

Chapter-5 Requirements		Compliance Demonstration
1.8	A distributor must provide: a) a description of the consultation(s), including • the purpose of the consultation (e.g. Regional Planning Process); • whether the distributor initiated the consultation or was invited to participate in it; • the other participants in the consultation process (e.g. customers; transmitter; OPA); • the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and • an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.	NPEI has created a standard consultation form, the Chapter-5 Consultation form or C5C Form, which will document the purpose of each consultation activity, whether the distributor initiated the consultation activity or was invited to participate in it, the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation, and an indication of whether the consultation is expected to affect NPEI's DSP. NPEI's staff involved in any consultation work will populate it, and store it along-side any consultation deliverables (e.g. meeting minutes, survey result tables, interview notes, etc.).
2) Identify Customer Needs, Preferences, Priorities		
2.1	Provide details of the mechanisms to engage customers (surveys, system data analytics and analyses, by rate class) regarding customer needs/preferences/priorities (e.g. regarding data access, renewables, behind the meter services, DG, storage, rates, level of service, CDM)	NPEI tracks customers' inquiries, complaints & feedbacks on a continuous basis through its customer integrated system (CIS). NPEI provides details on this mechanism in the Baseline Report. In particular, if and when new "types" of comments are being recorded by the customer service representatives (CSRs), this would show in the monthly call analysis, a new label would thereby be created and subsequently monitored. This mechanism guarantees legacy trends are monitored, and new trends are identified swiftly. The results of call analysis are filed with the Board on a monthly basis. NPEI Customer Service and IT reviews the call feedback on a monthly basis, identifies and assesses any trends, and makes adjustments to the call centre process as needed. NPEI confirms that calls regarding data access, renewables energy connection, distributed generation, behind-the-meter services, electricity price and rates, level of service, and conservation and demand management (CDM) are being monitored in terms of volume. Energy storage inquiries have not been identified so far as a call type because few to no calls have been registered on this topic area. NPEI has described in the Baseline Report how it intends to inform its customers about storage. NPEI might receive calls on storage as a result of the information dissemination to come, and will therefore register, then track it using exisitng mechanisms. NPEI currently has the following channels to receive feedback from its customers and key stakeholders: tracking customers' inquiries and comments through phone calls, transactional survey, and public-utility committee meetings. NPEI will bolster these channels as described in the Customer Engagement Plan. As needed, NPEI will add additional standard questions to ask customers that are interacting with representatives to obtain a more comprehensive database of customer preferences, needs and priorities. As DS planning progresses, NPEI will identify any new issue emerging from customer comment that may necessitate customer input, and will implement, as appropriate, customer input opportunities though website, tweets, other; and track, analyze, and provide the input to Operations/Engineering for addressing in DS planning. NPEI, starting in 2014, will carry out a Customer Satisfaction Survey. In 2014 NPEI will conduct a set of in-depth phone interviews and site visits with commercial and industrial customers for key customers, will deploy on-going methods to consult with technical service providers (or indirect customers) in its territory. NPEI will describe the observations, findings and conclusions from the 2014 in-depth phone interviews,and from the on-going indirect customer consultation, as well as implications on the DSP, on an annual basis in the Year-End report. To foster continuous improvement, the Year-End report will identify any issues in seeking customer input during the previous year, and will identify actions, as necessary, to improve performance. NPEI proposes to lay out observations, findings and conclusions from all of the above engagement on an annual basis in the Year-End report.
2.2	Provide details of the stages in DS planning where the information in 2.1 was used, and how/where the DSP has been affected	The DSP filed with the Board contains a description of the customer input received and how it was addressed in the DSP. In intervening years until the next DSP filing, NPEI will describe its observations, findings and conclusions from the engagement work, as well as their implications on the DSP, on an annual basis in the Year-End report.

	Chapter-5 Requirements	Compliance Demonstration
3) Facilitate Customer Access to Energy Consumption Data and Behind the Meter Services		
3.1	• Describe the options considered to facilitate customer access to consumption data in an electronic format • Identify, analyze and document mechanisms considered for real time data access considered to provide customers with ability to make decisions affecting electricity costs	NPEI has a portal through which it provides access to its customers to their energy data in electronic format, as well as electronic bills -- That is: "myAccount". Customers above 150kW also have interval meters. For these larger customers, the energy data is provided on a real-time basis. NPEI has tracked customers feedback on myAccount and has upgraded its myAccount platform as a result of this feedback. NPEI will carry on monitoring feedback on its data-access platform as laid out in 1.1. NPEI will describe and document all of the aforementionned options to facilitate access to customer data in an electronic format in detail in its Baseline Report. NPEI will update that description on a yearly basis in the Year-End report, highlighting any improvements that will be made to these options year-to-year.
3.2	Identify, analyze and document actions of behind the meter services and applications considered to provide customers with ability to make decisions affecting electricity costs	NPEI handles all comments and inquiries on high bills, electricity price and rates with a high degree of care. Representatives help the customer to access their energy data through the myAccount portal, they explain to them the influence of weather, and then they educate them about energy price and rate setting in Ontario, regulated price plan, and electricity retailers. They refer them to external sources of information on how to reduce their energy use and/or to the NPEI CDM team. The CDM program focuses on assisting the customer with behind-the-meter solutions to reduce electricity demand and consumption and to manage electricity bills more effectively. NPEI will update this information, as needed, on an annual basis, include it in the Year-End report and highlight any improvements made year-to-year.
4) Consult with the Ontario Power Authority, with the Regionally Interconnected Distributors and with the Transmitter		
4.1	• Document participation in any Regional Planning process (e.g. IRRP) • Provide final consultation deliverable document with DSP if available; if not available document status of consultation, role of NPEI, expected final deliverable date; indicate if/how consultation may affect DSP	NPEI will obtain a letter from OPA and from HONI that no regional process is currently under way. NPEI will continue to monitor any potential regional planning processes which will impact NPEI and will update the Customer Engagement Plan, to reflect any needed actions, accordingly.
4.2	Consult with regionally interconnected distributors and the transmitter in preparing the DS Plan	NPEI only interconnects with HONI. NPEI will send letter to HONI advising that NPEI is preparing its DSP for 2014 filing, and identify any potential issues and request feedback. NPEI will then send a letter notifying HONI that its DSP is being finalized and confirm how any issues related to HONI have been resolved. NPEI may integrate a web page to provide customers with information on regional processes. NPEI will populate it with the letter from the OPA that no regional process is currently underway. Whenever the situation will evolve (not anticipated within the period covered by the DSP), NPEI will use the same page to inform its customers and local stakeholders about the opportunity to participate in the regional processes, and how they may become involved.
4.3	Provide regionally interconnected distributors, transmitter and OPA information on forecast load, forecast REG connections and any planned network investment to accommodate connections; investment involving smart grid that could have impact on assets serving regionally connected utilities, and the results of projects or activities involving demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned over the forecast period	NPEI only has points of interconnection with Hydro One. NPEI will send letters to OPA and Hydro One, providing this information in advance of its DSP filing with the Board and will include those letters in its DSP filing. NPEI will follow up with NPEI and Hydro One on any matters arising from the material sent and address/document concerns and their resolution in its DSP filing.
4.4	For REG Investments: Send OPA a letter (60 days if REG, and 30 days if no REG) in advance of date distributor needs letter for inclusion in DSP, requesting a letter of comment from OPA on: the applications OPA has received from renewable generators through FIT for connection in NPEI service territory, whether distributor has consulted with OPA, or participated in planning meetings with OPA; the potential for coordination with other distributors/transmitters on implmenting the REG investments and whether the REG investments in DSP are consistent with any Regional Infrastructure Plan; and file any distributor response letter to the OPA.	NPEI does intend to do investments related to REG during the 5 year DSP plan horizon, and thereby will send to the OPA a letter 60 days in advance of the filing of the DSP, requesting OPA provide comment on the matters described in 4.7. The letter to the OPA will be contained in the DSP filing. NPEI may prepare a response letter to the OPA letter and if so, will file the response letter with the DSP filing.

Appendix B – Customer Engagement Strategy Matrix

NPEI 5-Year Customer Engagement Strategy

Goal 1	Goal 2	Goal 3
• Contribute to Achievement of Customer Focus Outcome	• Provide Framework to Meet Chapter 5 Engagement Requirements	• Develop Principles to Guide Customer Engagement

Customer Focus Outcome: Services provided in a manner that responds to identified customer preferences

Principles of Customer Engagement	Strategic Engagement Plan Response	Outcome	Metrics
Take an integrated approach to customer engagement	Leverage existing points of customer contact for broader based information gathering	Efficient engagement, minimal customer fatigue	# survey respondents per quarter
	Implement broad based customer inquiry	Investigate DS, smart grid, renewables, CDM, regional, other needs	Yes/no -- Survey includes all list of topic areas
	Involve utility staff across departments in engagement plan	Inquiry covers key aspects of DS planning	Yes/no -- Steering Commitee gathers all DS planning consultation topics, & updates the list on an annual basis
		Coordinated, effective planning and plan	Yes/no -- All quarterly Steering Committee meetings take place Yes/no -- Annual customer engagement report (year-end report) is prepared Yes/no -- Engagement Plan is updated on an annual basis
Take a long term perspective	Apply principles over 5-year period of DSP	Consistent inquiry strategy over DSP planning horizon	Yes/no -- 5-Year Strategy is prepared Yes/no -- Metrics are compared against target on a yearly basis, then updated
Participate in regional planning	Engage customers in any regional planning processes, as appropriate	Customers understand and have opportunity for input into broader planning context	Yes/no -- Availability of contact points # participants in regional planning contact points
Serve present and future customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Solid basis for monitoring and tracking trends	Yes/no -- Recurrent consultation activities include standing consultation questions year over year on key aspects
		Demonstration that customer needs/priorities/preferences are served by DS Plan	Yes/no -- Write-ups are included in year-end report on main consultations observations and findings, and implications on DS planning
Align utility interest with customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Understanding of customer needs/preferences/ priorities	Yes/no -- Open-ended questions to customer are included in consultation approach, on every given year, to allow for new trends and concerns to rise to the surface Yes/no -- Standing questions help NPEI understand trends in customer needs, preferences and priorities
		Integration of customer needs/preferences/priorities in DS planning and Plan	Yes/no -- Write-ups are included in year-end report on main consultations observations and findings, and implications on DS planning
Provide information on engagement opportunities	Provide meaningful opportunities for engagement	Increase in perception that customers feel they are being consulted and their views are being addressed	Measurement of degree to which customer perceives customer was consulted (e.g. on a 1-to-10 scale) Measurement of degree to which customer feels concerns addressed (e.g. on a 1-to-10 scale)
Measure engagement performance	Identify and track engagement performance metrics	Solid basis for monitoring and tracking trends	Yes/no -- All contact points are thoroughly documented in a standard manner
Achieve continuous improvement in engagement	Assess engagement performance at key intervals and make adjustments, as appropriate	Increase in representativeness of consultation and number of participants	Yes/no -- Over the course of each 2-year Engagement Plan, all rate classes are engaged with
		Increase in the perception of customers that they are being consulted, and that their views are being addressed	Measurement of satisfaction (e.g. on a 1-to-10 scale) that customer is being consulted and views being addressed
		Increase in satisfaction of participants in consultation, including consultation format and media used	Measurement of satisfaction (e.g. on a 1-to-10 scale), regarding the consultation activity the customer has just partaken in
		Increase in the level of relevance or usability of the consultation outputs	Departmental consultation -- Yes/no -- whether there has been improvement on usability of engagement outcome over last year
Carry out engagement consistent with Mission/Values/Vision	Engage customers with integrity, fairness, responsibility respect, transparency and provide best possible service	Customer engagement meets same standard of excellence as other utility activities	Yes/No -- All contact materials are systematically and properly reviewed for compliance before being taken to market
Carry out engagement consistent with Conditions of Service and any relevant corporate policies	Review Conditions of Service and relevant corporate policies in Plan development/ delivery	Consistent approach to customer engagement	Quality assurance review for conformity done as part of annual engagement reporting

Appendix C – Customer Engagement Plan Matrix

NPEI Customer Engagement Plan: 2014-2015

Consultation Activities - description, timing, purpose

Provides a detailed customer consultation plan that lays out consultation activities and mechanisms, and the tracking and reporting that will be done to document plan delivery. the dates shown in the matrix are completion dates except where it is an ongoing activity

ID Consultation Activities	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1) Engagement-Plan Governance Framework																							
1.1) Finalize Engagement Plan							X																
1.2) Draft Engagement-Plan Baseline Report							X																
1.3) Annual Engagement Reporting & Planning Cycle																							
Gather and Group All Feedbacks for Ending Year											X												X
2014 Year-End Report														X									
2015-2016 Customer Engagement Plan														X									
1.4) Quarterly Steering Commitee Meetings	X		X		X		X		X		X			X			X			X			X
2) Education and Information to Customers																							
2.1) Document Customer Service and IT Systems							X																
2.2) Document Information to Customers on Outages and First Responses							X																
2.3) Document Information to Customers on Capital Improvement Projects & Construction Work							X																
2.4) Document Information to Customer on REG Opportunities, Modalities & Connection							X																
2.5) Document Approach to Providing Access to Energy Data to Customers							X																
2.6) Document Approach to Educating Customers on Energy Bills and Price							X																
2.7) Document CDM Engagement Actions							X																
2.8) Inform Customers and Stakeholders About Energy Storage Activities, then Document It							X																
3) Customer Data Collection and Consultation																							
3.1) Market Characterization Interviews								X															
3.2) Market Characterization Site Visits								X															
3.3) Tracking of Customers' Inquiries, Complaints & Feedbacks																							
Tracking is an on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will integrate tracking consultation topics with that of other engagement work									X														
3.4) Transactional Survey																							
Transactional surveying is an on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will improve the recording of survey responses, and integration of the consultation topics with that of other engagement work									X														
3.5) Bi-Annual Customer Satisfaction Survey					X																		
4) Service-Territory Stakeholders Consultation																							
4.1) Monthly Stakeholder Meetings (a.k.a. Public Utility Commission Meetings)							X																
Stakeholder meetings is a monthly, on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will improve the integration and documentation									X														
4.2) Consultation with Customers' Technical Service Providers (professional/trades)										X													

ID Consultation Activities	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
5) Participation in Regional Consultation																							
5.1) Consult in Regional Processes																							
Obtain letter from OPA and HONI that no regional process is currently under way							X																
5.2) Consult with Regionally Interconnected Distributors																							
Send letter to HONI advising that NPEI is preparing DSP for 2014 filing				X																			
Send letter to HONI notifying that DSP is being finalized							X																
5.3) Consult on REG Interconnection																							
Provide Board-prescribed information to HONI and OPA					X																		
Follow up with HONI and OPA							X																
5.4) Consult on REG Investments																							
Send letter to OPA as prescribed by Board					X																		
Prepare and send a response to OPA letter as required							X																

Appendix D – Chapter-5 Compliance Form (C5C Form)

niagara peninsula energy Inc.

CHAPTER 5 COMPLIANCE FORM FOR CUSTOMER ENGAGEMENT ACTIVITIES

NPEI Staff Responsible	Name:		Job Title:	
Consultation Activity Title				
Brief Description				
Purpose				
NPEI's Role	☐ Initiated Activity		☐ Invited to Activity	
	☐ Chair	☐ Facilitator	☐ Participant	☐ Other: ___________________
	NPEI Staff Involved *(Name, Title)*:			
Details	Location:		Date:	Number of Participants:
	Participants: *If only a few, please be specific and list name(s) and organization(s); if many, please list general target audience(s):*			
	Status of consultation activity *(e.g. complete, # additional meetings scheduled, # of total topics covered, etc.):*			
	List hyperlink(s) or cross reference(s) to relevant materials or attach as an appendix (*if applicable):*			
Results (If applicable)	Next steps or nature of final deliverables *(e.g. meeting minutes, transcripts, tabulated survey results, Regional Integrated Resource Plan):*			
	Timing of final deliverables *(if applicable)*:			
Is the activity expected to affect the Distribution System Plan?	☐ Yes		☐ No	
	If so, how?			

This form is intended for NPEI Staff to document consultation activities that result directly from the Customer Engagement Plan. This form should be used to document major consultation activities such as CDM events, participation in regional planning activities, the send-out /completion of a customer satisfaction survey, focus group sessions that relate to a particular consultation activity, regular meetings with municipalities, and monthly or quarterly interviewing activities (not the results of individual interviews).

APPENDIX H

2014 Customer Engagement Baseline Report

NPEI Customer Engagement Baseline Report

August 15, 2014

Submitted to:
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1 Introduction

The Customer Engagement Baseline Report (Baseline Report) is the first report which documents the activities to date, related to the implementation of the 2014-2015 Customer Engagement Plan, and thereby will serve as a baseline for future status reports on these activities. NPEI plans to update the Baseline Report annually, providing a status report – a Customer Engagement Year-End Report – on activities for the intervening period and highlighting any improvements made. The Customer Engagement Baseline Report will be filed with the Distribution System Plan (DSP) in August 2014.

The Baseline Report consists of a description of 2014 NPEI customer education, engagement, information and technical assistance activities current to June 30, 2014. This includes information on:

- Current customer education and information practices date (e.g., customer views needs/preferences/priorities).
- Customer consultation (e.g., inquiries, comments and complaints monitoring, surveying and direct engagement)
- Stakeholder consultation (e.g., regular meetings with local municipalities)
- OPA and HONI consultation (e.g., correspondence related to regional planning activities)

The type of information gathered for each component will vary depending on the activity. Where appropriate and known, an indication may be provided as to whether the consultation is expected to affect the Distribution System Plan or associated planning. With experience in preparing year-end reports, the type of, and approach to, documentation will evolve over time.

1.1 Methodology for Baseline Report

The Baseline Report requires the collection and documentation of information from across NPEI departments. Since it is also one of the key deliverables of the Customer Engagement Plan, which is overseen by a cross-departmental committee, the Steering Committee[1], the Steering Committee also directed the preparation of the Baseline Report, under the coordination of the Chief Conservation Officer.

ICF International (ICF) was retained by NPEI to assist in the preparation of the Baseline Report. ICF prepared a detailed outline of the report, a description of information needed for the report, and assigned the information gathering and reporting to particular departments; and populated the outline with information already gathered in the preparation of the 2014-2015 Customer Engagement Plan and information from the NPEI website. Each Steering Committee member coordinated the preparation and review of draft information in the Baseline Report under the member's purview, and also reviewed the draft Baseline Report, which was compiled by ICF from the information provided. ICF finalized the Baseline Report based on the comments received from the Steering Committee.

[1] The Steering Committee is comprised of the following NPEI staff: President and CEO; VP Customer Services & IT; VP Engineering, VP Finance, VP Operations; and Chief Conservation Officer.

The Baseline Report is expected to serve as a template to be updated for the preparation of the annual Customer Engagement Year-End Reports. It will be modified and enhanced over time with experience gained.

1.2 Improved Documentation Practices

NPEI intends to improve its documentation practices regarding customer engagement and its integration into distribution system planning and the distribution system plan.

In order to improve the consistency in NPEI's documentation of consultation work, NPEI created a standard consultation activity form, the Chapter-5 Consultation Form or C5C Form, which will be used by NPEI staff to document consultation activities that result directly from the Customer Engagement Plan. The C5C form is shown in Appendix A.

2 Education and Information to Customers

This section presents detailed descriptions of the customer education and information activities.

2.1 Call-Center Tracking of Customers' Inquiries, Complaints & Feedbacks with Implications on DS Planning

NPEI has a set of tools and interface for handling, categorizing, tracking, assessing and addressing customer inquiries and complaints.

NPEI Role in Activity

NPEI has a customer call centre which is managed through the Customer Services & IT department. There are a number of Ontario Energy Board (OEB/Board) reporting requirements related to the call centre (e.g. reporting on Service Quality Indexes (SQIs), the Board's Scorecard). These are reported on by NPEI elsewhere.

Description

NPEI logs, categorizes and tracks all customer inquiries, complaints, and feedback received from incoming calls and correspondence received into the call centre. NPEI's customer service and billing representatives register every inbound or outbound call in NPEI's Customer Information System (CIS): Harris Northstar product suite.

The Customer call centre encompasses incoming and outgoing calls into and from Customer Service and Billing. Customer inquiries are queued and directed to an appropriate representative based on selection of queue. For each call received, the call is categorized by type of call (Overdue, Account Inquiry, Power Interruption, and Conservation). General inquiry calls are filtered by function of the call: move, new service, and general billing inquiry (high bill, inquiry, payment method, meter read). Calls received for complaint or compliment are noted separately in order to track and follow up.

Utilization of the Harris Northstar customer care functionality, along with the Harris Executive Information System, provide a dashboard displaying call volume reporting by call type, allowing NPEI to break down call volume by representative, department, and call type. NPEI is able to track calls on each of the queues including outages (during and after), high energy bills, payment arrangement, energy data access platform(s), CDM (and each of the CDM programs), renewable energy generation matters (REG), and capital improvement projects and construction work, along with all account specific inquiry or request by call type.

A call can be assigned to a specific department or employee for follow up, and reporting of the progress of the call. Each action on the call is date and time stamped in order for NPEI to report on service quality: length of time to resolve issue, and results of the resolution. Where necessary, if a call is escalated, a recording of the call is attached to the call and referenced for follow up by supervisor. All documentation or written correspondence relative to an inquiry or request is attached to the account for reference.

On a monthly basis, NPEI's Vice President of Customer Services & IT reviews the call feedback, identifies and assesses any trends, and makes adjustments to the call centre process as needed. In particular, if and when new 'types" of calls are being recorded by the representatives, this would show in the monthly analysis, a new label would thereby be created and subsequently monitored. This mechanism guarantees legacy trends are monitored, and new trends are identified swiftly. The managers of Billing and Customer Service as well as Lead Hands of those departments take part in review of the calls to determine course of action. Training is scheduled with staff to maintain up to date communication. The review process allows managers to determine when more detailed scripting is required to assist representatives in providing correct, current, and timely information to the customer.

Results to Date

Reporting in place provides review of what types of calls are processed. High call volumes are determined and use of the Interactive Voice Response reports provides information to management on required number of resources and service quality indices (number and percentage of calls received, handled, and abandoned, and results of the queue usage). To date, payment arrangement is the highest volume of calls received. Collection calls and balance inquiry (automated dial call) rank as the next highest of calls received. On average, 10% of active customers call into the utility monthly.

Moving Forward

NPEI plans on improving its use of the call tracking by making enhancements to: planning, organizing and integrating the call types, comparing results against that of other consultation activities across departments, decision-making and taking actions across departments, and documenting planning, feedback and review.

The integration of Customer Care to operations Call Taker System will provide efficiencies as today users are entering calls relative to power outages in both systems. Further the integration will allow for a toggle free environment to assist representatives when speaking to the customer.

This work may be expected to affect the DSP planning by providing more comprehensive information related to customer needs, preferences and priorities by topics of interest to customers. This may also result in information which may be used to adjust the implementation of the DSP. The analysis of the data will be provided to the NPEI Steering Committee for consideration in determining how this information is to be treated in the DSP and in ongoing DSP planning and implementation.

2.2 Outages and First Responses

NPEI has tools and procedures related with the management of communications surrounding outages, and then the retrieval, gathering and handling of feedback from customers. These tools include information technologies and multiple communication channels. This section provides a description of the work done, tools, protocols and typical sequences of action.

NPEI Role in Activity

NPEI receives calls from direct or indirect customers signalling the outage and handles these calls to locate the outage and organize first response. NPEI informs direct and indirect customers about the outage, showing it has the situation under control, and informing customers about the expected duration of the outage.

Description – Unplanned Outages, First Response and Feedback

NPEI monitors unplanned outages through its Customer Call Centre during normal working hours and Answering Service after hours. Representatives input all of the calls into the Call Taker System, as well as the Customer Information System, which includes information such as time and location, and feed the data into the Outage Management System (OMS). NPEI's Control Room Operator along with Engineering Staff diagnose the cause of the outage, prepare a first-response plan, provide an estimated duration of the outage to Customer Services where practical, and dispatch one or many teams of Line, Engineering and Metering Technicians to the field to carry out the required inspections and repairs. Customer Services then provides the information on outage location and estimated time of reestablishment of service to all of the representatives so that they can inform the next callers. Customer Service and Billing representatives responding to calls use the Call Taker System to provide location of outage and estimated time to restoration. This information goes on NPEI's website; if warranted by the magnitude of the situation NPEI also disseminates the information on social media (NPEI has a Facebook and a Twitter feed), and for a severe outage of more than 4 hours and/or affecting more than 1,000 customers, may broadcast the information on the local radio.

During normal working hours, NPEI captures data provided from smart meters installed on the system, and has linked the meter status to the customer premise modelled within the Geographic Information System (GIS) to track meters reporting outages. The Control Room Operator then determines the response required based on predictions provided by the Outage Management System. Based on the number and location of meters reporting, the OMS performs a trace back to the first major device on the system to predict the location of first response. The Operator then dispatches the Work Order to the lap-top computer installed within the Truck of the closest Crew to the affected area to perform the inspections or repairs required. The Crews locations are tracked within a sub-set of the GIS called In-Service, to aid the Operator in decisions required for the response. Once the restoration is complete, the Operator is able to poll a sample of meters whose status had shown out, to poll the current status and determine if the situation has been resolved. The crew then closes the Work Order on their lap-top and the Operator closes off the Outage.

After normal working hours, the Answering Service provides the same support as the CSR's and dispatches the outage information to one of two On-Call Line Technicians. Depending on the magnitude of the situation, the responding Line Technician will either implement the repairs required, or Call in a Control Room Operator & representatives based on a set of criteria provided to them.

NPEI has SCADA access to all of its feeders sourced from Hydro One-owned Transformer Stations, namely Stanley & Murray T.S., Beamesville T.S., Vineland D.S.; and NPEI-owned Kalar M.T.S. and Grimsby Powers Niagara West T.S. The access to the information is provided through an Inter-Control Center Communications Protocol (ICCP) link and provides breaker status, voltage, and current. The Operator monitors these outputs on a regular basis to maintain proper operating limits of the feeders.

NPEI monitors positive or negative feedback on outages from customers from call-center tracking and social media. Since NPEI keeps a record of the source and time of the call, NPEI can directly link up a certain batch of feedback with every specific outage. Customer Services organizes internal de-brief sessions as needed; in particular, for continuous improvement. First-response procedures are improved accordingly.

During major weather events, NPEI Control Operators are in direct contact with Law Enforcement Municipal Officials, and other public utilities through the supply of a reserved Phone Line, for easier access to Staff when call levels are abnormally high, by-passing the normal protocols through the Answering Service or representatives. Often they are able to provide valuable feedback to probable outage causes or immediate public safety concerns which may assist the Operator in prioritizing Crew deployment.

NPEI Staff have protocols to follow while re-establishing power during outage events, prioritized as follows: 3-phase Main Feeders from T.S.'s sourcing Municipal Sub-stations, with supplies to critical loads taking precedence; next are 3-phase main feeders supplied by Municipal Sub-stations; then fused 3-phase laterals followed by fused 1-phase laterals; and then transformers, secondary buss, followed by individual services. Negative feedback from customers may be received during major weather events; for example, noting that utility trucks just drove past a house out of power and didn't stop, not being aware that this procedure is due to the applicable protocols. The protocols concentrate on re-supply to the most customers or critical loads first, and can be difficult for the customer to understand. The customer needs to better understand that although it may seem inefficient for trucks to return, it is the most time effective solution for restoration to the majority of customers.

Description – Planned Outages

Engineering works with Customer Services to prepare and provide information on scheduled outages, and outage preparation through the NPEI website. Outage preparation is designed to help customers prepare for a power outage; there is an on-line document which provides guidance to customers on how to prepare for an outage. There are tips on an emergency kit and other necessities, and what else a customer might need in the event of an outage. In addition, there are tips on what to do during the outage and what to do after the power is restored.

For Planned Outages of up to 500 Customers, NPEI will provide three days' notice to customers via hand delivered letters dropped off to each customer's mailbox by a Technician. Date, time, rain date and the contact Technician are outlined in the letter. Customer Service is provided with the account numbers and the date and time of the outage to be input within the CIS to aid representatives with questions from customers.

For Planned Outages over 500 Customers, NPEI will provide a weeks' notice to customers via direct mailings, radio station and newspaper notification. The Corporate Website is updated with the relevant information and Customer Service is provided with the accounts dates and times to update the CIS to aid representatives with questions from customers. Whenever a customer contacts NPEI, the representative will poll the customer's account and update contact information within the CIS for future reference.

Results to Date

NPEI tracks information on all outages via the Outage Management System which records and archives the relevant data. Information from this system is used to provide the stats required by the Board, namely SAIDI, SAIFI & CAIDI, on a yearly basis.

NPEI has gained valuable insight during the period of 2013-2014 regarding trends of widespread outages. From the Lincoln/West Lincoln area, review of information has determined a requirement to fortify lightning mitigation equipment within the system, as highlighted by a large number of failed transformer/step-down units during large lightning events. Within the Niagara Service Area the implementation of insulated base switch components resulted from a review of outages caused by animal contacts/pole fires. The Service Truck has also been given direction to replace porcelain insulated cut-outs with polymeric insulated components due to a failure rate captured by the OMS.

NPEI has utilized an Auto Dialler to warn customers about planned outages in these situations with limited success, as out-dated cell phone numbers and provision of emergency contacts by customers may not be relevant to the location where the outage will occur. Since the message is taped, and incapable of providing answers to questions, the information may not be relevant to the person answering the call (often a work number is provided).

Moving Forward

Outage management is a critical part of customer service. As a result any improvements in data collection and analysis to understand more thoroughly customer needs, preferences, priorities and satisfaction with NPEI's outage management is important for consideration in the DSP plan development and in plan implementation. The analysis of the outage data will be provided to the NPEI Steering Committee for consideration of how this information is to be treated in the DSP and in ongoing DSP planning.

NPEI is implementing a Pilot Project using Wi-Max Communication Systems to remotely monitor the status of feeders sourced from NPEI-owned Municipal Stations located within the Lincoln/West Lincoln Service Area, to provide real time data to the Operator. The distribution in this area is mainly rural, with associated long feeders to minimal loads in areas with limited communication options. The scope involves the installation of D.C. back-up systems, communication networks including towers and base stations, and the upgrade of reclosures & station breakers with communication-enabled equipment. With the information provided by this system, the Operator will have another valuable tool to aid in operational decisions, to more effectively dispatch crews, track the location of faults based on fault current inputs, minimize feeder patrol times and improve restoration times during large weather events.

2.3 Capital Improvement Projects and Construction Work

NPEI disseminates information about planned capital improvement projects and construction work on its system. The information is provided to educate customers about the project and to minimize customer inconvenience. The following section describes the triggers, frequency, and nature of information and communication channels used to disseminate information on these projects.

NPEI Role in Activity

NPEI plans capital improvement and construction work well in advance, coordinates with the affected municipalities and other utilities, plans communications surrounding each of these projects and carries out these activities according to the plan.

Description

NPEI disseminates information about upcoming projects and construction work through its website. Currently on the NPEI website there is a list of 2013 highlighted capital projects. NPEI plans on updating the list for 2014 projects.

There are a large number of routine projects that take place each year, particularly related to operations and maintenance activities. NPEI decides on what projects to undertake from information based on cyclic inspections and equipment replacement programs. These include Pole Inspection & Replacements, Municipal Sub-station Inspections & Maintenance/Refurbishments, Pad-mounted Equipment Inspection & Replacements, Kiosk Inspections & Replacement, Minor Sustainment Programs, Demand Based System Expansions, Manhole & Sidewalk Vault Inspections, Rebuild/Reinforcement/ Conversion Construction, and Road Relocation Works.

For specific capital projects, NPEI delivers letters and notices directly to the mailboxes of the affected customers 30 days before the start of the construction. If the magnitude of the project warrants it, NPEI has hosted Public Information Sessions near the area affected. This is to ensure any customer concerns can be addressed whenever practical.

NPEI also disseminates information on upcoming projects through, local radio broadcast, publications in the local press, and the use of social media, as warranted.

Results to Date

The amount and nature of communications needed is scalable; it may not be appropriate to deploy all of the tactics listed above for every project. Specific decisions about the approach are made on a project-by-project basis at the planning stage, and then included in the project workplan and budget.

Once done with the construction stage and once the new infrastructure gets energized, NPEI conducts internal debriefing sessions to identify success factors, lessons learned, and improve its practice looking forward.

Moving Forward

NPEI plans to enhance the information provided on its website. In 2015, NPEI plans to provide the list of budgeted projects for capital works for 2015 at the beginning of the calendar year. NPEI will provide an expanded but short description of each listed project. NPEI will also provide a summary, high level description of the planned maintenance.

NPEI will update the site bi-annually to indicate which projects have been completed, deferred, etc. A standard categorization will be used to report on progress.

NPEI will provide a short justification for these projects, highlighting the benefits to the community and/or the consequences of not proceeding with the investment, and perhaps a generic write up that explains the linkages between NPEI proceeding with these capital improvement and rates increases.

At this time NPEI does not foresee the provision of budgetary amounts or expenses related to projects on the Corporate Website. Direction from the Board of Directors is required for the release of this information. If required, this information could be disseminated on a case by case basis with approval from the Board. Further expansion regarding on-going maintenance and inspection programs can be provided to help customers understand how projects are prioritized and approved.

NPEI has decided to improve its distribution system planning to include customer solicitation as to what projects or initiatives are important to our customers. In providing information about capital projects, NPEI plans to provide ongoing progress reporting of capital projects and the impacts or benefits of the work that NPEI is doing.

2.4 REG Opportunities, Programs, Modalities and Connection Procedures

This section presents the customer engagement procedures and processes related to renewable energy generation (REG) opportunities for NPEI's customers and information on the responsibilities and activities of the full-time engineering technician that provides technical assistance to customers.

NPEI Role in Activity

NPEI provides information on its website and through its call centre regarding REG connection and also provides technical assistance regarding connection.

Description

NPEI currently maintains web content regarding REG connection. The website contains information regarding renewable generation to assist customers in obtaining approvals regarding connection to the NPEI distribution system and guidance on the Ontario Power Authority's Feed-in-Tariff programs (FIT programs). The website includes requirements for connecting embedded generation and details on each of the FIT programs and how to register.

NPEI has standard procedures to follow when a representative receives a telephone inquiry about REG. The initial information is recorded by the representative within the service location report system and the customer is provided with the contact information for NPEI's REG Technician. Relevant documentation is compiled, and a service location report is completed by the Technician outlining the responsibilities of the Proponent & NPEI, including any costs for which they are responsible. Connection impact assessments are initiated where relevant, payments are tracked, and when construction of the facility is complete, and upon receipt of the ESA Inspection Certificate, NPEI line staff with the REG technician perform a witness test to ensure the customer's system performs to the requirements outlined within the connection documents. All REG's are modelled within the Geographic Information Systems, documentation is signed off, contracts and test results are hyperlinked to the customer premise in the GIS, and the OPA is contacted with the connection results and details.

NPEI can share details of the REG connection requirements through an information package sent to customers, upon request; the package is also accessible on the website. The information package contains information regarding the requirements for embedded generation including site classification for energy generation facilities, safety, power quality and protection requirements, the generation connection process, a description of all necessary technical reviews, connection impact assessment, charges, metering requirement, approval, revenues available and financial settlement options. The information package was developed in 2012, and is updated based on changes to the program.

The representatives are trained to handle general inquiries related to REG and to send out the REG-connection package. Typical REG inquiries are related to capacity availability; responses include, for example, areas of system constraints, capacity availability, and inspection & witness testing scheduled dates.

To further assist customers, NPEI has a full-time engineering technician to address questions and to facilitate connection. Typical information and assistance provided by this individual includes: applicable estimates and costs, metering requirements, wiring & metering schemes, scheduling the connection & witness test, liaise with the OPA upon completion of the connection, and finalize the paperwork & provide relevant information to the Billing Department. The engineering technician does not provide advice regarding behind the meter REG matters.

NPEI can provide information and education on REG connection to the distribution system. Customers seeking help on technical aspects of REG behind the meter may be referred to vendors and service providers.

Results to Date

NPEI connected 87 MicrofFIT in 2013 and 25 MicroFITs in 1st Quarter 2014, with 6 FITs connected during the same time frame. In total, NPEI has connected 315 MicroFIT's, 12 Fit's and 9 Net Metered installations since the start of the Program. There has been a downward trend in requests due to known system constraints outside of NPEI's direct control, namely Short Circuit limitations at Niagara West T.S and Hydro One issues on the 115KV Transmission System in conjunction with the Allanburg Station. NWTS is in the process of installing Current Limiting Reactors at the T.S. which will enable additional FIT connections, with an associated Capacity Fee to any future Proponents. Completion of equipment installations is anticipated for the fall of 2014. Hydro One is also in the construction phase of equipment installations required to remove the constraints currently in place with the 115KV Transmission Network.

Moving Forward

NPEI plans to continue to monitor customer information needs and responses to the information and technical assistance provided.

Other than system constraints out of the direct control of NPEI, as outlined previously, there do not seem to be any issues with the REG Process used by NPEI. It is anticipated that a large volume of requests will resume once the constraints have been lifted, but in most cases, the technician has started the paperwork in anticipation of the capacity release, so NPEI does not anticipate any delays processing the backlog.

2.5 Access to Energy Data to Customers

This section presents a review of the options made available by NPEI for increasing customer data visibility. It includes information on the options available to the customer, and how NPEI will how survey customer preferences with regard to access to account and energy data and account update.

NPEI Role in Activity

NPEI provides access to account and energy data to customers. NPEI selected a customer web portal technology and a vendor for the technology; worked with a vendor to carry out the database integration and new portal customization work; took the new energy data platform to market; and is maintaining and operating the system in collaboration with the vendor, and can work with the vendor to upgrade the system, as required. NPEI monitors the new technological options, new features and add-ons and potential upgrades as they arise, consults with its customers, will select which options, features, or add-ons to roll out, and will proceed with the upgrades in response to customer preferences. The web portal will provide enhanced self-service features to our customers.

Description

NPEI has named its account and energy data access service, myAccount. NPEI has purchased the NorthStar Utilities Solutions: eCARe V2 and Customer Connect platforms.

NPEI provides access to energy data to customers through its myAccount web portal. The myAccount platform is accessible to all customers. The myAccount web portal allows customers to log on to a secure website to access their bill, payment and consumption histories, log service calls such as update of customer personal information, move, service requests such as tree trim, power outage, account review, pay accounts, and submit meter readings. Customers can access their account information and data anytime, as long as they have a browser and access to broadband internet. Both desktop and mobile views are available. For customers that are inaccessible to a computer or internet connection, a computer desktop is made available for customers to use from the Niagara Falls Head Office location.

All billed customers can view meter readings, and usage, with graphical display of time of use or hourly consumption where applicable. In addition to the myAccount web portal, all general service accounts above 50 kW and have an interval meter, and have access to Utilismart website to view the interval meter data. Large commercial customers can use the website to manage load and forecast energy costs.

To date, NPEI has been promoting its myAccount portal to foster utilization through bill inserts, envelopes, customer contact/call centre, website, and dissemination of information through its webpage, and social media.

The myPortal account allows customers to extract energy data information for analysis in a pdf or excel format.

Results to Date

MyAccount has improved customer service and has proven to be beneficial to our customer in learning how they are using their energy. High bill calls have decreased since the inception of myAccount. When time of use periods are updated, customers are educated to use the next-day view of consumption to determine how consumption is used.

Based on customer feedback into the customer call centre and correspondence, NPEI will provide self service tools to complete moves, apply for payment options such pre-authorized payment plan or equal payment plans, and request and retrieve data requests for customer or affiliate use.

Future enhancements such as text to customer, instant message to customer, customer alerts based on balance or consumption thresholds will be looked at in 2015.

To date, 13% of the active customer based is enrolled on myAccount. The increase to use of the myAccount product increases 1-2% per month. Through the use of conservation marketing messages and programs, NPEI promotes a greener environment, encouraging all of our customers to move to ebill and use of the myAccount portal.

Moving Forward

NPEI plans to continue to monitor customer information needs and responses to the information and technical assistance provided.

Through the NPEI website, as well as within the MyAccount web portal, NPEI encourages customers to provide comment, compliment, or complaint. These online requests are electronically transferred to the customer account as presented in the Customer Information System, and forwarded to appropriate area of the organization for update and response to the customer. Using the call tracking reporting, procedures and processes are updated, and options are made available to the customer. For example, in the call centre, tree trimming and check meter reads were a high volume call. To assist the customer, tree trim, power outage, check meter became online service requests that the customer can enter in the My Account web portal at a convenient time for the customer, rather than make a call into the utility during business hours. Any feedback directly related to a project or scope as outlined in the DSP is communicated to Engineering and Operations electronically.

With further integration between the customer information system and the Call Taker system, information will flow efficiently, amongst multiple departments and will facilitate consideration for DSP planning purposes.

2.6 Customer Education on Electricity Bills and Price

This section lays out the methods by which NPEI informs customers about electricity bills and pricing, including for example, rate structure, time-of-use billing, regulated price plan, market prices, weather normalization, reasons for rate increases and other matters as they arise.

NPEI Role in Activity

NPEI addresses high electricity bills calls as they arise. NPEI disseminates information and educational materials about electricity consumption and how to manage bills.

Description – High-Bill Call Handling

NPEI addresses high electricity bills calls as they arise and seeks to soothe any discontentment of calling customers. This is done through a diligent correction of any error on energy bills, if any, which is relatively rare, and through education on energy use, energy rates and energy management at the time of the call.

When a representative receives inquiries, complaints or comments related to customer electricity bills and prices – often these are regarding energy bills that the customers see as unreasonably high, hence these calls are referred to as “high-bill calls” – the representative goes through a standardized sequence of actions that includes:

- Diagnosing the problem through cognitive dialogue,
- Prompting the customer and helping the customer to access the myAccount platform,
- Providing direct education using the dataset and the different reporting tools of the myAccount platform,
- Showing to callers the cause of the high bill, for example, and depending on what the issue was:
  - Extreme weather,
  - Board-approved rate increase,
  - High electricity use during TOU summer peak period,
  - Potentially behind-the-meter equipment failure or malfunction, etc.
- Referring the callers to CDM resources such as the saveONenergy rebates and educational materials, or the NPEI CDM group.

The education process has been successful and as a result, high bill calls are not repetitive on an account. Typically, the education of the customer on how the customer is using energy, the communication and outline of customer tools available such as myAccount web portal, and CDM programs will resolve the issue. Customers are using the tools available; as typically, when the portal is not available, the customer is notifying NPEI as to its availability. Maintenance windows of the portal are communicated via the website and customer feedback, when myAccount is updated, is received.

Description – Unsolicited Customer Education

NPEI uses correspondence, standing web items, bill inserts, dynamic social media and the myAccount platform (See Section 2.5) to disseminate information and educational materials about electricity consumption and how to manage it. NPEI also disseminates information about energy price, rate setting, regulated price plans, time-of-use, market price, rate setting, and electricity retailers.

In some cases NPEI distributes content and educational materials, such as a time of use information packet, to educate customers on the smart meter, time of use. Updates to the regulated price plan are provided via website and bill insert (provided by the Ontario Energy Board.) Useful links to Ministry of Energy, Independent System Operator, Ontario Power Authority, and Ministry of Health are found on the website. Necessary links are added as feedback is provided. For example, we tracked an increase in the number of calls relative to the health risks associated to radio frequency and the smart meter. We sourced Ministry of Health documentation and provided it and a link onto our website to the inquiring customers. Where customers seek advice on retailers, we assist with bill comparison so that customers can make their own informed decision.

Local schools will request information regarding electricity, electricity safety and conservation. Materials and utility representation are provided to provide an informational session to Grade 5 students. Ten schools within the service territory are done each year. Material is put together to offer an interactive session that works with the curriculum.

NPEI also conveys content and materials developed by the OEB, the IESO, the Ministry of Energy and the OPA such as the OEB Bill Calculator, or the OPA's LDC-specific saveONenergy web platform (https://saveonenergy.ca/?ldc=npei).

NPEI provides links on its website regarding its rate filing and opportunities to participate in the rate proceedings.

Other items of information provided to the customer include how to understand the customer's consumption, walk through of usage and how to read the smart meter (this assists with high bill inquiries), how rates are determined, and how rate classifications are determined.

Results to Date

Unsolicited customer education is a continual improvement and progress initiative. The review of call types and information from our customers, along with the activity within the industry, direct NPEI to offering new information sessions and tools.

Moving Forward

NPEI has purchased an interactive survey tool that will be used at the end of each electronic correspondence to customers to solicit feedback regarding what topics interest the customer and the format to receive the information. Based on recent trends related with inquiries regarding electricity rates and how to manage electricity costs, NPEI has decided to improve its distribution system planning to include customer solicitation as to what projects or initiatives are important to our customers. In providing information about capital projects, NPEI plans to provide ongoing progress reporting of capital projects and the impacts or benefits of the work that NPEI is doing.

Use of interactive tools such as Customer Connect available from the web portal, myAccount, will allow customers to manage their electricity costs through view of their detailed consumption, set up of alerts direct to them when energy consumption goes beyond a threshold or directly communicate programs that may benefit them, whether it is a CDM program, Payment Assistance Program, or educational forums of relevant topics.

2.7 CDM Engagement Actions

This section contemplates the direct customer engagement work done by NPEI's CDM professionals and delivery agents as well as mass-market communications used by NPEI to advertise OPA-contracted province-wide CDM programs.

NPEI Role in Activity

NPEI is the program administrator of OPA-contracted province-wide CDM programs in its service territory. NPEI delivers all of the OPA-contracted province-wide CDM programs that OPA has made available to LDCs. NPEI manages the customer relationship regarding these programs either directly, through the assistance of delivery agents and channel partners, or both.

Description

NPEI delivers the residential, low-income, commercial and industrial OPA-contracted province-wide CDM programs in its service territory. As part of program delivery, NPEI uses an array of direct and indirect customer engagement approaches from one-on-one customer meetings, to customer group events, to participating in broader community activities/events, all of which are designed to complement the overarching province-wide program marketing of the OPA. CDM Staff act as an applicant rep, assist with the saveONenergy application process for vendors and applicants, and encourage DES studies, and energy audits to drive deeper savings. CDM staff meet with customers on a regular basis or by phone, identifying customer needs and assisting with CDM opportunities.

NPEI CDM professionals maintain ongoing relationships with the four local municipalities within its service territory and the broader Region of Niagara. NPEI is also an active member of Niagara Erie Power Alliance (NEPA) group.[2] In addition, NPEI participates in GridSmartCity Utility Partners Co-operative[3], which aligns with the provincial government's interest in LDCs' finding ways to achieve greater efficiencies in scale and scope in their operations, which may include: advancements in self-healing grids, electric vehicle infrastructure, conservation program implementation, renewable energy initiatives and cooperatives and community energy planning.

[2] NEPA is comprised of 10 utilities: NPEI, Fortis-CNP, Norfolk Power, Brant County Power, Brantford Power, Grimsby Power, Niagara on the Lake Hydro, Welland Hydro, Haldimand County Hydro, and Horizon Utilities.

[3] Utility partners include: NPEI, Waterloo North Hydro, Cambridge and North Dumfries Hydro, Kitchener-Wilmot Hydro, Burlington Hydro, Oakville Hydro, Kingston Hydro Corporation, Guelph Hydro, Milton Hydro and Halton Hills Hydro. Quarterly meetings are held.

NPEI is a member of the Niagara Electrical Association and Niagara Industrial Association. NPEI staff attend Chamber of Commerce events for the Town of Lincoln and the City of Niagara Falls. CDM staff work with the City of Niagara Falls Business Development Office to promote CDM programs.

NPEI CDM staff have fostered a collaborative relationship with Town of Lincoln and City of Niagara Falls municipal staff. Of particular note is that CDM staff worked closely with municipal staff to develop an Energy Management Plan for the City of Niagara Falls, based on building energy audits, and the Plan was submitted to the Ministry of Energy. In addition, staff worked closely with the Town of Lincoln on the new Community Centre regarding energy efficiency and with energy retrofits related to existing buildings.

NPEI uses the services of delivery agents to complement its technical assistance to customers and its marketing efforts. For example, NPEI uses a delivery agent to review and make recommendations on the approval to NPEI of applications under the commercial and industrial programs. NPEI also retains the services of a marketing company to assist with development of mass marketing and educational materials related to CDM programs. NPEI manages service provider-initiated customer engagement through activities such as direct mail, phone campaigns, and breakfast and lunch information sessions.

NPEI has retained a roving energy manager (REM) through the OPA's REM program. This has enabled NPEI's CDM staff to provide more technical services to identify and assist with identifying commercial and industrial customer projects and to provide a more comprehensive approach to energy conservation within customers' facilities. It has also enabled NPEI to reach more commercial & industrial customers. Typically, NPEI's REM will meet with customers through site visits, identify and review opportunities for CDM and assist the customer in moving forward in seeking incentives from CDM programs.

In 2014 NPEI's leadership role in CDM was recognized by the OPA through the awarding of Conservation Fund project to explore the feasibility of load-shifting the battery charging of electric golf carts in golf courses and non-road electric vehicles in industrial facilities, with a view to a broader province-wide roll-out.

NPEI takes a leadership role on CDM matters with LDCs through participation in CDM and related committees. NPEI's Chief Conservation Officer (CCO) is a member of CFAWG, the Conservation First Advisory Working Group, which is taking the lead in working with the OPA to design the details around the new CDM framework for 2015-2020. The CCO is Past Chair of the EDA Communicators Council[4]; Vice Chair of the EDA CDM Caucus, and serves as a member of the EDA Emergency Task Force and the Conservation Reporting Working Group.

Results to Date

NPEI is working diligently to meet its 2014 CDM demand and energy savings targets. Despite considerable effort expended by NPEI in cooperation with other LDCs, customers, channel partners and stakeholders to overcome operational and structural issues that limit OPA program effectiveness across all market sectors in NPEI's service territory, challenges remain; and there is limited opportunity to make adjustments to the existing suite of OPA programs. NPEI can build on the strengths and successes of the 2011-2014 programs in the new CDM framework. Details on

[4] The CCO was chair in 2012 and 2013 of the EDA Communicators Council, which addresses CDM and other utility communications matters.

NPEI's CDM performance are available in NPEI's CDM Annual Reports, which are posted on the NPEI website. Results for 2013 will be available on September 30 2014.

Moving Forward

NPEI retained ICF International in January 2014 to identify the achievable potential for conservation by sector and subsector, consistent with the OPA achievable potential results for the province, and to identify key subsectors for further market characterization, such that these sectors could be targeted in Q4 of 2014 and into the new CDM framework. The market characterization will include direct one on one customer engagement as well as interviews with key subsector market players.

This work may affect the distribution system planning by providing specific information related to customer needs of particular commercial and industrial subsectors that have been studied as part of the achievable potential work. Once the work is complete, it will be submitted to the NPEI Steering Committee for consideration in determining how this information is to be treated in the DSP and in ongoing DSP planning.

2.8 Electricity Storage

This section includes a description of the new energy storage activities taking place across the province as well as locally.

NPEI Role in Activity

NPEI provides information to customers, through its website and call centre, regarding energy storage.

Description

In March 2014, the Minister of Energy established new policy regarding the procurement of electricity storage in Ontario, setting procurement targets for the OPA and for the Independent Electricity System Operator (IESO).

In response to this new policy and to assist customers in understanding the new storage procurement opportunities, NPEI developed a plan for enhancing its website and its call centre tracking system to provide information and assistance to customers regarding this policy.

Results to Date

NPEI has been monitoring government policy regarding the procurement of electricity storage.

Moving Forward

NPEI intends to enhance its website regarding electricity storage by adding a storage section which links with both the OPA and IESO storage sites and by providing general information related to the government policy and procurement opportunities. In addition, in conducting the monthly review of call centre data, reviewers will be mindful of any emerging trends regarding caller interest in storage and consider tracking storage as a separate topic, as warranted. As part of the biennial customer survey, questions related to storage were included, such as interest in storage, whether energy storage was of interest to the customer.

This work may affect the distribution system planning by providing specific information related to customer preferences and needs based on the level of interest (e.g. number of hits to storage site, number of calls) in storage. This information can be used to help to determine the likely level of customer participation in the procurement opportunities. The level of interest and success of that interest will determine whether storage will affect the DSP and DSP planning.

3 Customer Consultation Work

Customer consultation work includes direct one on one customer engagement through interviews, site visits, call centre surveys and other forms of customer survey.

3.1 CDM Market Characterization Customer Interviews and Site Visits

This section includes a description of the plan for market characterization customer interviews and site visits.

NPEI Role in Activity

Market characterization site visits take place for particular market segments that have the potential to achieve electricity savings to contribute to meeting NPEI's electricity savings targets in 2014.

Description

NPEI is making progress toward meeting its CDM targets by the end of 2014. To help ensure that NPEI meets these targets, NPEI retained ICF International in January 2014 to identify the achievable potential for conservation by sector and subsector, consistent with the OPA achievable potential results for the province, and to identify key subsectors for further market characterization, such that these sectors could be targeted in Q4 of 2014 and into the new CDM framework. The market characterization will include direct one on one customer engagement as well as interviews with key subsector market players.

As part of the one on one engagement, ICF International in July-August of 2014 will conduct site visits to particular facilities and customer interviews within the targeted subsectors to obtain a better understanding of customer needs, preferences and priorities related to CDM and will also take the opportunity to ask particular questions related to broader customer issues such as customer bills, time permitting. These latter questions will be added to the CDM interview protocol to be used by ICF staff conducting the site visits. The site visits will be attended by NPEI's CDM staff as well, as time and scheduling permitting.

Results to Date

NPEI updated its customer data in the spring of 2014 to provide a current NAICS code for each customer. This enhanced data set was used by ICF International to model achievable potential results based on OPA's achievable potential, but customized to NPEI's service territory. These results make it easier for NPEI to do targeted engagement by subsector and will also make the results of the achievable potential work more accurate. It will enable NPEI to more readily identify customers within key subsectors for market characterization site visits and interviews.

The achievable potential results identified some key subsectors that may warrant further market characterization work; wineries, greenhouses, poultry operations and hotel/motels. Two subsectors were chosen for market characterization work: greenhouses and hotel/motels, as these offered the greatest potential savings. The market characterization work is underway; site visits and customer interviews for greenhouses and hotels/motels are near completion.

Moving Forward

The initial achievable potential results will be adjusted based on the market characterization work for greenhouses and hotels/motels, once completed. Particular opportunities for savings capture in each of these sectors will be identified including potential technologies to focus on and strategies to address market barriers.

This work may affect the distribution system planning by providing specific information related to customer preferences, needs and priorities related to CDM and other distribution system planning matters for the greenhouse and hotel/motel sectors. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee once the results of the site visits and interviews are available.

3.2 Call-Center Transactional Survey

This section contains a description of the planned improvement to the call tracking system in order to use in-bound calls to survey customers on different matters including, but not limited to, their satisfaction with the service they just received, and whether the issue they were reporting has been resolved. The transactional survey could also be used to obtain other sorts of customer feedbacks without causing any disruption by an unsolicited survey call or email.

NPEI Role in Activity

NPEI has a customer call centre which is managed through the Customer Services & IT department. NPEI modifies its procedures, as well as its CIS system, to be able to record answers to one or a few additional questions lodged at the end of an in-bound call. NPEI plans ahead, and then changes the set of questions from time to time, in order to broaden the number of research questions.

Description

NPEI's representatives deliver transactional-survey questions. These are part of their regular call script. For example "Would you like additional information regarding how to save energy or the current conservation programs?"; "You have a scheduled outage occurring in your area; have you received the dropped off letter? Would you like this information in a different format: phone, email, text?" In review of your account, you have paid using online banking, would be interested in pre-authorization payment plan?" The call scripts are changed based on trends of call types and feedback from representatives. For example, the most recent change was rate change scripting.

Results to Date

The current approach to transactional surveys is working well. However, the transactional survey responses could be tracked and tabulated in a more organized manner. NPEI has begun to identify a set of enhancements for the transactional survey. Answers to date are not stored in a manner that eases tabulation and interpretation, thereby making it challenging to draw meaningful conclusions and make decision based on feedback.

Moving Forward

NPEI will use its CIS system, as well as, an integrated survey tool to register the responses. Follow up calls and outgoing call scripts will be used to follow up on survey questions.

Moreover, NPEI will plan consultation topics in a more integrated manner along with all other consultation topics across all other consultation activities. This will allow NPEI to schedule transactional survey questions in advance to ensure coverage of a broad number of topic areas; and then tabulate and use the results in concert with results from other consultation activities to draw conclusions, make decisions, take actions and document them.

This work may affect the distribution system planning by providing more and enhanced information related to customer preferences, needs and priorities which can be considered for integration into the DSP and ongoing DSP planning.

3.3 Biennial Customer Satisfaction Survey

This section introduces the new customer satisfaction survey that NPEI will conduct to reach out to the "silent-majority" customers; that is, those customers who usually do not call or reach out to NPEI to provide direct feedbacks. NPEI will roll out a first version of the survey starting in May 2014, and then conduct a similar survey every second year.

NPEI Role in Activity

NPEI determines the need for, and overall content of, customer satisfaction surveys that may take place under its direction.

Description

NPEI retained UtilityPulse to conduct a customer satisfaction survey in May-June 2014. UtilityPulse compared NPEI results with those of Ontario and nationally. Some key results of the survey include:

- UtilityPulse found that the attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. Overall, NPEI on demonstrating credibility and trust, scored 80%, which is higher than the provincial score of 77% and in line with the national score of 80%.
- 84% of electricity bill payers are very or fairly satisfied with NPEI, compared to the Ontario score of 83% and the national score of 89%.
- 82% of customers agree that their next contact with NPEI will be a good or positive experience, which is better than the provincial score of 79% and in line with the national score of 82%.

Details of the survey results are contained in the 2014 rate filing.

Results to Date

Details of the survey results are contained in the 2014 rate filing.

Moving Forward

The results of the survey will be discussed at a Steering Committee meeting and will be integrated into the DSP planning process, as appropriate. The survey will be conducted at least every two years.

4 Service-Territory Stakeholder Consultations

Service-territory stakeholders consultation activities include, but are not limited to, CDM market characterization interviews, meetings with local and regional municipalities and utilities in the Niagara area, and consultations with technical service providers that provide direct assistance to NPEI's customers.

4.1 CDM Market Characterization Market Actor Interviews

This section includes a description of the plan for the market characterization market actor interviews and the expected results.

NPEI Role in Activity

Market characterization interviews may take place with particular market actors that have the potential to assist NPEI in understanding particular markets, and in identifying and implementing strategies to capture more program participants and electricity savings to contribute to meeting NPEI's electricity savings targets in 2014.

Description

NPEI is making progress toward meeting its CDM targets by the end of 2014. To help ensure that NPEI meets these targets, NPEI retained ICF International in January 2014 to identify the achievable potential for conservation by sector and subsector, consistent with the OPA achievable potential results for the province, and to identify key market players to assist with understanding particular markets. The market characterization will include interviews with market players (for example, vendors, contractors, or influential trade associations) doing business in particular segments and having influence on customer investment decisions in energy intensive systems such as lighting, air conditioning, electric heating and ventilation.

As part of the one on one engagement, ICF International in July-August of 2014 will conduct market player interviews to gain a better understanding of market barriers and customer needs, preferences and priorities related to CDM.

Results to Date

Interviews will market players are near completion. Site visits for greenhouses and hotels/motels, the two subsectors chosen for detailed market characterization work, are near completion. The results are being compiled, integrated and analyzed.

Moving Forward

Particular opportunities for CDM savings capture in each of these sectors will be identified including potential technologies to focus on and strategies to address market barriers. This will provide greater understanding of customer needs regarding CDM and how to address them effectively in 2014. It will also provide guidance on strategies to address CDM customer needs in the new CDM framework.

This work may affect the distribution system planning by providing specific information related to customer preferences, needs and priorities related to CDM in the key market segments of greenhouses and hotels/motels. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee once the results of the market characterization work are available.

4.2 Results of Regular Stakeholder Meetings

Regular stakeholder meetings (Public Utility Committee meetings – PUC meetings) consist of the monthly in-person meetings that NPEI participates in with key local stakeholders such as local municipalities and Niagara Region, Enbridge Gas Distribution, and the local cable and phone companies.

NPEI Role in Activity

Staff from NPEI's engineering and operations departments attend PUC meetings as a participant with other stakeholders in its service territory, referred to as Public Utility Committee meetings.

Description

NPEI participates in the local Public Utility Committee meetings hosted by the two designated Municipalities that NPEI services. These monthly meetings are attended by municipal and regional authorities, electric utilities, communication & cable T.V. utilities, gas utilities, and the Ministry of Transportation & the Ministry of Labour.

Minutes of the meeting are recorded and made public, and include discussions of short and long term planning of the various agencies in order to co-ordinate efforts, prepare budgets and mobilize staff as required, wherever relocation or rebuild work may involve any of the attending agencies.

Results to Date

NPEI regularly attends and participates in PUC meetings and keeps the meeting minutes. There is an opportunity for NPEI to take a more proactive role, as required, to try to address key distribution system planning issues through the meeting agenda.

Moving Forward

NPEI will be cognizant of the opportunity to engage stakeholders at the PUC in its distribution system matters, as appropriate. NPEI may also set up and/or attend ad hoc meetings with particular members to discuss relevant system planning matters, as appropriate. These activities are expected to lead to lead to more effective use of this engagement forum and ultimately, will contribute to a more integrated planning approach to NPEI's customer engagement and more effective reporting on engagement activities.

PUC results may affect the distribution system planning by providing specific information related to regional planning issues and the impact of regional stakeholders on NPEI's distribution system planning and plan. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee, based on the reporting to the Committee by the Operations and Engineering departments members of PUC meeting results.

4.3 Consultation with Technical Service Providers

This section presents a description of consultation activities with technical service providers, also referred to as indirect customers.

NPEI Role in Activity

Staff from NPEI's Engineering and Operations departments has informal meetings with customers' technical service providers on an ongoing basis. These include tradespeople, professionals involved in new REG connection, behind the meter servicers, etc.

Description

The technical service providers of customers provide valuable insight into customer needs, preferences and priorities. As a result, NPEI Engineering and Operations department staff meets informally with them to obtain information related to market segments, customer satisfaction, the perceived quality of service and avenues for improvement.

Results to Date

Meetings to date have been productive and helpful for distribution system planning. There is an opportunity to hold more formal engagement activities with customers' technical service providers in order to draw more meaningful and robust conclusions, and make decisions based on the feedback received.

Moving Forward

NPEI intends to proceed with a more formal approach to engagement with technical service providers in addition to maintaining informal engagement. The formal engagement will consist of directed cognitive phone interviews conducted by utility staff, following interaction with the service provider on normal business activities.

NPEI intends to use the information acquired through these consultations to identify requirements and attendees for focus group activities that are expected to take place on an annual basis in a central location.

Potential research questions include: perceived quality of new connection and REG service when compared with other nearby LDC where they also have business, power quality, quality of information available from NPEI, and potential improvement regarding the delivery of CDM programs.

Both consultation activities (interviews and focus group) are new, and will be rolled out in 2015. NPEI will do the planning for the phone interviews (e.g. questionnaire) in the spring of 2015 and expects to hold the focus groups in November or December of 2015. NPEI's Engineering and Operations departments will be responsible for carrying out this consultation on a regular basis based on a quota of interviews decided in advance by the Steering Committee.

This work may affect the distribution system planning by providing specific information related to customer preferences, needs and priorities for distribution system planning. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee, based on the reporting to the Committee by the Operations and Engineering departments members of consultation results.

5 Participation in Consultations with OPA & HONI

This section presents communications between NPEI and the Ontario Power Authority (OPA), and between NPEI and Hydro One (HONI) regarding distribution system planning matters.

5.1 Consultations in Regional Processes

The OEB has laid out specific requirements for consultation to be conducted by distributors related to regional planning processes. This section addresses how NPEI meets those requirements.

NPEI Role in Activity

NPEI is a participant in any regional planning. Regional planning is led by either OPA or HONI.

Description

NPEI monitors on an ongoing basis regional activities that may affect its distribution system.

Results to Date

To date there are no regional planning activities in Niagara Region. No regional planning activities are expected within the next 5 years.

Moving Forward

NPEI will endeavour to obtain a letter from OPA and from HONI confirming that no regional planning process is currently underway. NPEI intends to build a web page on its website to provide information on regional processes. NPEI will continue to liaise with OPA and HONI on regional planning processes that may affect NPEI.

Planned or launched regional processes may affect the distribution system planning and plan if regional processes go forward during the 5-yr DSP. Any potential effect on the DSP and distribution system planning will depend on the nature of the regional process and the timing of its deliverables and completion. Any such planning would be reported on to the Steering Committee and considered for integration into the DSP and planning, as appropriate.

5.2 Consultations with HONI

The OEB requires distributors to consult with regionally interconnected distributors and the transmitter in preparing the DSP. NPEI does not have embedded or host distributors, as a result NPEI consultation activities focus on HONI.

NPEI Role in Activity

NPEI consults with HONI on NPEI's distribution system planning to provide information to HONI on NPEI's distribution system planning and to obtain HONI input.

Description

NPEI consultation with HONI on its five-year DSP to be filed in its Cost-of-Service application of August 2014 is underway.

Results to Date

The letter from NPEI to HONI, regarding preparation of the DSP for filing, identifying any potential issues and requesting feedback was sent. To date no feedback has been received from HONI.

Moving Forward

NPEI will send a letter to HONI, notifying HONI when the DSP is being finalized and indicate how any issues related to HONI have been resolved, and how this was integrated into the DSP.

5.3 Consultations on REG Interconnection

Prior to filing a DSP, the OEB requires a distributor to provide the transmitter (in this case HONI) and the OPA specific information related to its DSP. The information covers matters such as: the forecast load, forecast REG connections, smart grid investments, planned projects and recent results of projects or activities involving innovative processes, and services, business models, or technologies.

NPEI Role in Activity

NPEI consults with HONI and OPA on REG connections within its service territory and related to its distribution system planning.

Description

NPEI consults with HONI and OPA on an ongoing basis regarding REG connection.

Results to Date

NPEI has initiated consultation activities with HONI.

Moving Forward

NPEI will send a letter to OPA and to HONI, providing the following information in advance of its DSP filing. The information covered: forecast load, forecast REG connections and any planned network investment to accommodate connections; investment involving smart grid that could have an impact on assets serving regionally connected utilities, and the results of projects or activities involving demonstration of innovative processes, services, business models; and on projects or activities of this nature planned over the forecast period. NPEI will follow up with OPA and HONI on any matters that arise from the information sent and address and document concerns, their resolution, and how this was integrated into the DSP.

5.4 Consultations on REG Investments

Prior to filing of the DSP, the OEB requires NPEI to send a letter to the OPA regarding distribution system investments related to REG.

NPEI Role in Activity

NPEI prepares material regarding distribution system investments related to REG for the OPA for comment and will address any comment received from the OPA, prior to filing of the DSP.

Description

NPEI assesses on an ongoing basis the need for distribution system investments related to REG.

Results to Date

NPEI sent a letter to OPA 60 days in advance of the filing of the DSP.

Moving Forward

NPEI will prepare a response letter to the OPA letter, if necessary, and integrate feedback obtained into distribution system planning and the DSP.

Appendix A – Chapter-5 Compliance Form (C5C Form)

niagara peninsula energy Inc.

CHAPTER 5 COMPLIANCE FORM FOR CUSTOMER ENGAGEMENT ACTIVITIES

<table>
<tr><td>NPEI Staff Responsible</td><td colspan="2">Name:</td><td colspan="2">Job Title:</td></tr>
<tr><td>Consultation Activity Title</td><td colspan="4"></td></tr>
<tr><td>Brief Description</td><td colspan="4"></td></tr>
<tr><td>Purpose</td><td colspan="4"></td></tr>
<tr><td rowspan="3">NPEI’s Role</td><td colspan="2">☐ Initiated Activity</td><td colspan="2">☐ Invited to Activity</td></tr>
<tr><td>☐ Chair</td><td>☐ Facilitator</td><td>☐ Participant</td><td>☐ Other: ___________________</td></tr>
<tr><td colspan="4">NPEI Staff Involved (Name, Title):</td></tr>
<tr><td rowspan="4">Details</td><td colspan="2">Location:</td><td>Date:</td><td>Number of Participants:</td></tr>
<tr><td colspan="4">Participants: If only a few, please be specific and list name(s) and organization(s); if many, please list general target audience(s):</td></tr>
<tr><td colspan="4">Status of consultation activity (e.g. complete, # additional meetings scheduled, # of total topics covered, etc.):</td></tr>
<tr><td colspan="4">List hyperlink(s) or cross reference(s) to relevant materials or attach as an appendix (if applicable):</td></tr>
<tr><td rowspan="2">Results (If applicable)</td><td colspan="4">Next steps or nature of final deliverables (e.g. meeting minutes, transcripts, tabulated survey results, Regional Integrated Resource Plan):</td></tr>
<tr><td colspan="4">Timing of final deliverables (if applicable):</td></tr>
<tr><td rowspan="2">Is the activity expected to affect the Distribution System Plan?</td><td colspan="2">☐ Yes</td><td colspan="2">☐ No</td></tr>
<tr><td colspan="4">If so, how?</td></tr>
</table>

This form is intended for NPEI Staff to document consultation activities that result directly from the Customer Engagement Plan. This form should be used to document major consultation activities such as CDM events, participation in regional planning activities, the send-out /completion of a customer satisfaction survey, focus group sessions that relate to a particular consultation activity, regular meetings with municipalities, and monthly or quarterly interviewing activities (not the results of individual interviews).

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APPENDIX I

NPEI IT Assessment

IT Assessment

Overview of IT Strategy and Capital Projects

Margaret Battista, Vice President, Customer Services & IT

CONTENTS

Executive Summary

The purpose of this document is to outline the business requirements considered in preparing the technology initiatives for the Capital Budget IT Expenditures. Within these requirements, all hardware and software, from all departments within the organization are addressed. Technical solutions address redundancy, business continuity and enabled process. This document will address strategy and overview of hardware and software capital expenditures.

The Information Technology capital expenditures ensure that Business Goals are aligned to technological solutions. Our network infrastructure is continually optimized allowing for improved business uptime and resiliency.

There are four areas for IT Capital Budget:

- Hardware
- Software
- Training
- Resources

The requests within each of these areas allow for the following goals to be met:

- Effective and Efficient Business Processes
- Support of risk and compliance management processes and methodology (enabling a methodology, not defining)
- Integrated, reliable, enterprise solutions
- Network Integration and Security
- Embedded business continuity practices, and Continued Update and testing of a Disaster Recovery plan

In meeting the established goals, Niagara Peninsula Energy Inc. (NPEI) technical solutions contribute to meeting the Board established utility performance outcomes:

- Customer Focus: Technical solutions are provided in a manner that responds to identified customer preferences: customers have access to consumption and usage information, account logistics, and bill information. Self-service user friendly tools are readily available for customers to open an account, change account information, apply for payment plans, view usage and billing information, ask questions. Internal utility staff has tools available to assist customers in reporting outages, establishing restoration timeframes, and provide distribution system status.
- Operational Effectiveness: Continuous improvement in productivity and cost performance is achieved; sound technical solutions assist the utility in delivery of system reliability and quality objectives.
- Public Policy Responsiveness: Current and future technical requirements are reviewed and solutions developed to ensure that utility can deliver on obligations mandated by government.
- Financial Performance: Financial viability is maintained; and savings from operational effectiveness are sustainable.

Planning of IT capital expenditures is based on established life cycle of both hardware and software; annual IT capital project plans leverage new and existing information systems technology through integration.

Regimented maintenance plans and renewal of technical solutions allow for planned expenditures over a five year period. IT project lifecycle encompasses investigation, requirement review and documentation, development, testing, procedural review and documentation, followed by end user acceptance testing and training. Production schedules are adhered; and no development is implemented without prior testing and training, with post implementation support.

Niagara Peninsula Energy adheres to Technical user acceptance and security policies. Incorporated within the IT strategy and IT capital project plans are the following information system technology investments to take place over the next 5 years:

- Business Continuity Planning/ Disaster Recovery Planning to mitigate risk to NPEI from a significant event (major power disruption, fire, loss of building, etc.)
- Server renewal and replacement meeting end of life support
- Network infrastructure enabling growth and efficiencies
- PC renewal and replacement meeting end of life support
- Printer renewal and replacement meeting end of life support
- Telephony hardware and software (including IVR and call center software, along with corporate telecommunications) maintenance upgrades to extend life and provide for operational efficiencies
- Projected software maintenance and upgrade to meet regulatory obligations, customer value and operational efficiencies; software upgrades are addressed in each of the business units: Financial systems, Customer Information System and affiliated sub-systems, Customer facing forms software, Geospatial Information System, Outage Management System, SCADA, Distribution System communications, Meter Data repository/Operational data storage, Inventory Control integrations including barcode software, Customer facing web portal software, Field level tools such as internal work orders and mCare used by Operational staff on tablets or in-truck lap tops, CDM program web portal software used to integrate customer information to usage of conservation programs
- Website update to extend life and maintain customer focus
- Security audits to responsibly address technical risks associated with loss of data, cyber security, policy review and adherence.

IT activities focus on activities that are aligned to NPEI's strategy and business requirements.

IT Strategy

Information technology expenditures ensure that business goals are aligned to technological solutions. Information technology expenditures are hardware, including network infrastructure, switches, servers, equipment, PCs, tablets, laptops, printers, plotters, projectors, phone and telecommunications; software including licensing and web solutions. Beginning with a business requirement, resilient and redundant integrated and secure solutions are put into place ensuring business continuity and sustainability.

There are four areas for IT Capital Budget:

- Hardware
- Software
- Training
- Resources including professional services

The requests within each of these areas allow for the following goals to be met:

- Effective and Efficient Business Processes
- Support of risk and compliance management processes and methodology (enabling a methodology, not defining)
- Integrated, reliable, enterprise solutions
- Network Integration and Security
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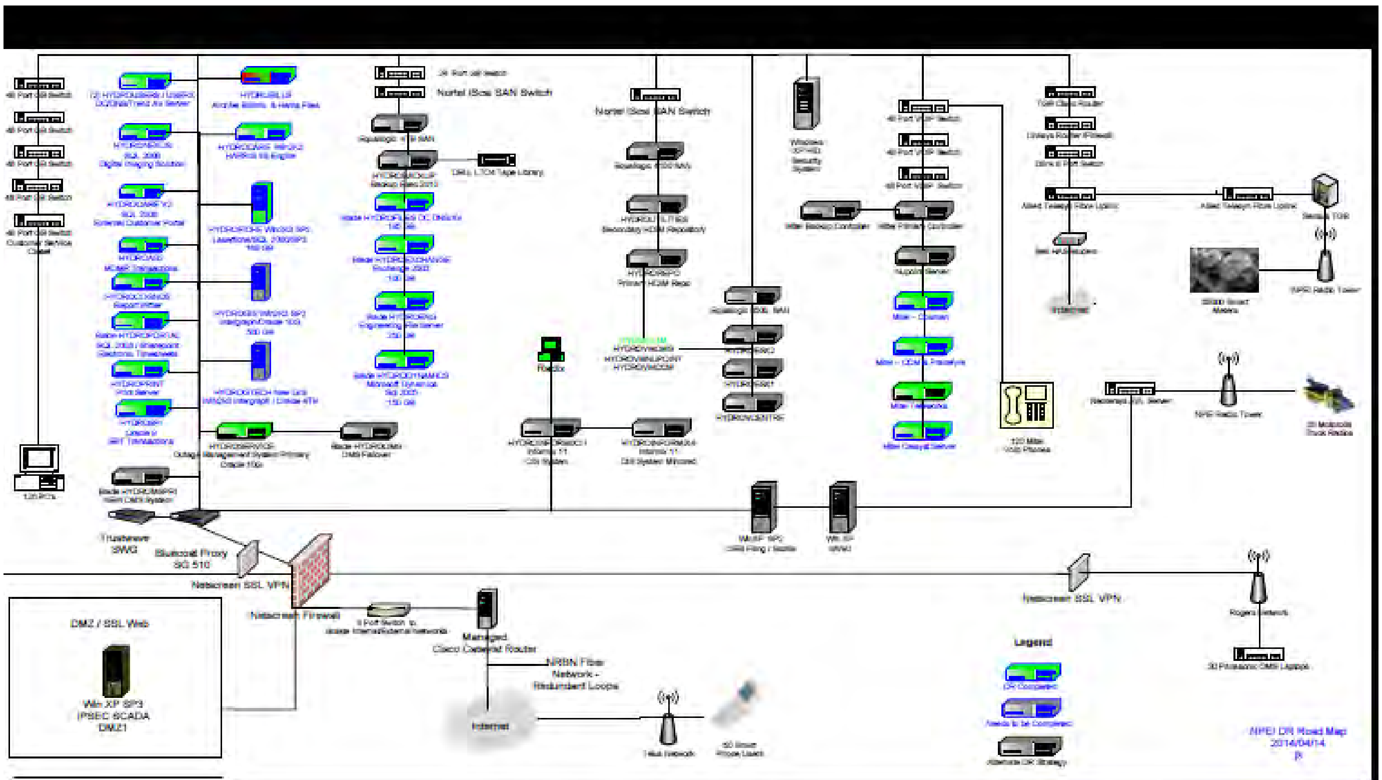
- Operational Effectiveness: Continuous improvement in productivity and cost performance is achieved; sound technical solutions assist the utility in delivery of system reliability and quality objectives.
- Public Policy Responsiveness: Current and future technical requirements are reviewed and solutions developed to ensure that utility can deliver on obligations mandated by government.
- Financial Performance: Financial viability is maintained; and savings from operational effectiveness are sustainable.

IT is responsible for an integrated sophisticated network. The following network diagram presents the intricacies of the support and magnitude of the disaster recovery plan to be put into place to ensure core business processes are available for business function. The network allows for growth and a lifecycle approach to both and hardware and software ensures that the infrastructure remains current.

The goal of the business continuity and disaster recovery plan is a three tier approach: for each server put into place, redundancy is built within the server, backup to tape and disk is completed, a mirrored server is available in two locations: NPEI's Smithville office, as well as, third party outside of NPEI's service territory. Currently, NPEI IT is working to having all core systems within the Disaster Recovery infrastructure. Core systems include: customer information system and integrated sub-systems, finance systems, geospatial information system, outage management system, and operational data storage. Over the next five years, the goal is to have each of these systems tested within the mirrored environments (Smithville and third party) and to include future new requirements related to inventory management, phone systems, WIMAX and SCADA.



Hardware

Spending of hardware will be managed with continued emphasis on new business requirements, network infrastructure and disaster recovery. Purchases of hardware are directly related to building on resiliency and redundancy achieving measurable results meeting the needs of software to be implemented and improved business practices.

Costs are related to the following projects/business need. If hardware or equipment is scheduled to be purchased based on renewal or replacement, the year to replace is based on 5 year lifecycle specific to hardware/equipment use.

- Barcoding equipment providing operational efficiencies of inventory;
- Cell phones renewal and replacement; cell phones are integral part of communication strategy for on-call, in-field and management staff;
- Mail machines (equipment) for processing of customer outgoing communications;
- Maintenance and replacement of legacy Radix handhelds (equipment) to read few conventional meters. New purchases of meter reading handhelds are not scheduled due to smart meters; the purchase of handhelds is based on necessary replacement due to repair to support conventional meters during implementation of MIST meters.
- LCD projectors renewal for use in Boardrooms and meeting rooms;
- Improved Network Infrastructure resulting in purchase of switches and servers; taking into account growth and expansion of data requirements. Server purchases include renewal based on age, purchase of server for new business requirements specific to backup strategy, upgrade of financial software (Great Plains), disaster recovery build, WIMAX and SCADA.
- Workforce/Outage Management Ongoing Implementation, integration and support (including migration server)
- Upgrade of PC's, laptops, tablets, and printers due to age and use. Laptops and tablets are used in the field by management, operations and metering staff. The use of laptops and tablets in the field provide operational efficiencies in response time and accuracy of information.
- Purchase of required office phones, renewal and extension of life of phone system integration and support.

One method of maximizing IT investment is continual monitoring of hardware, building redundancy on core systems. This is a continual process improving network infrastructure.

This is accomplished in the hardware expenditures of additional network switches, update of proxy, wireless access points, improved backup solutions, along with the creation and implementation, including testing of the Disaster Recovery Plan which would document the process, policies and procedures of restoring operations critical to the resumption of business including regaining access to data (hardware, software, records), communications (incoming/outgoing telecommunications), and workspace.

Key business processes including Outage Management, Phone system added functionality of Integrated Voice Recognition, as well as, integration into the Outage Management tools and need for redundancy outline the business need for additional hardware such as servers, hardware relative to phones.

In order to maintain tools that allow for efficient processes, we cycle through phones, PCs and Printers based on age and need.

The following table represents the expenditures over the next 5 years.

Sum of Cost		Year					
Type	Category	2015	2016	2017	2018	2019	Grand Total
Hardware	Barcoding Equipment	25,000					25,000
	Cell phones			25,000			25,000
	Equipment	3,250	13,250	13,250	3,250		33,000
	LCD Projectors	1,000	1,000	1,000	1,000		4,000
	Network	30,000	24,000	12,000	24,000	12,000	102,000
	PC / Monitor	64,600	69,000	62,000	29,000	75,000	299,600
	Phones	25,000	92,700	26,640	2,400	2,700	149,440
	Printers	6,500		6,050	20,900	24,600	58,050
	Servers	80,000	43,150	100,000	160,000	122,000	505,150
Hardware Total		**235,350**	**243,100**	**245,940**	**240,550**	**236,300**	**1,201,240**

The average annual hardware costs over forecasted 5 year period is anticipated to be $ 240,248.

Software

Software required for business process improvement projects and new requirements, which promote efficiency and reliability including the following. The following projects are categorized by department.

- All departments: Adobe Read/Write and Visio licenses
- All departments: Update of Windows operating system
- All departments: Microsoft developer network
- Finance: Great Plains upgrade and reports
- Finance: Timesheets
- G&A&Ops: Optimization of stores and inventory management through implementation of Accellos bar code customization and software
- Billing: Upgrade of CIS 6.x
- Billing and Engineering: Continue the integration between operations sub-systems, m-care and inservice to the CIS to improve customer relationship management (Update of workforce/outage management tools including the review and capability of the use of the other mobilized ruggedized tablets in the field)
- Billing and Customer Service: Continue to incorporate automation platform within the CIS to automate workflows and build upon business analytics used in decision making.

- Billing and Customer Service: : Continue to update current daily, monthly, quarterly reports from Cognos 7 format to Cognos 8 format, leveraging improved functionality from a desktop automated tool
- Customer Service: Telephony updates to address outage messages (being able to automate response to customers at time of outages, providing timely up to date information to the customer) These updates can also be used to add efficiencies to collection calls as well as time in queue: Alertworks
- Continue to incorporate workflow tools through the use of File Nexus in Human Resources, Engineering, and Conservation
- Address risk management through security audits of all network infrastructure including web applications
- Engineering: Support of Rugged.com/WIMAX and SCADA solution
- Customer Service and Conservation: Website improvements, Mobile GO payment application
- Continue with solution of an enhanced backup solution promoting redundancy and business continuity
- Continued support of an effective enterprise solution that will have the following characteristics:
    - Security – information is secured and has access control
    - Scalable – accommodates growth
    - Cost – value for money
    - Manageable – provides the ability to manage implementation including version control
    - Portable – accommodates changes in technology.

The enterprise solution has both application server (hardware) requirement, as well as, software components.

The following table represents the software expenditures over the forecasted 5 years.

Sum of Cost		Year					
Type	Category	2015	2016	2017	2018	2019	Grand Total
Software	All		74,500				74,500
	All departments					7,200	7,200
	Billing	100,000	25,000	25,000	25,000	175,000	350,000
	Customer Service		66,300	41,300			107,600
	Disaster Recovery					50,000	50,000
	Engineering	140,000			75,000		215,000
	Engineering & HR		1,000		1,000		2,000
	Finance			35,000	15,000	40,000	90,000
	G&A&Ops	100,000					100,000
	Operations	61,000	103,000	76,800	75,000		315,800
	Operations & Engineering	20,000	20,000	20,000	20,000		80,000
	Professional Services	67,000	67,000	67,000	67,000	141,102	409,102
	Security					40,000	40,000
	(blank)				2,500		2,500
Software Total		**488,000**	**356,800**	**265,100**	**280,500**	**453,302**	**1,843,702**

The average annual software costs over forecasted 5 year period is anticipated to be $ 368,740.

Conclusion

We continue to be committed to delivery of sound technical solutions and services to both our internal and external customer. Solutions will be efficient and effective, aligned with the priorities of business initiatives.

APPENDIX J

2014 Grid Modernization Strategy

1.0 NPE Grid Modernization Plan - Rev 2014

1.1 In 2009, the Ontario Green Energy Act amended OEB licence conditions for local distribution companies. As a result, NPE is required to prepare plans for the development and implementation of a smart grid. Strategic investments must then be made in accordance with these plans.

1.2 According to the Ontario Electricity Act, "smart grid" is defined as:

... advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of:

(a) Enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;

(b) Expanding opportunities to provide demand response, price information and load control to electricity customers;

(c) Accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or

(d) Supporting other objectives that may be prescribed by regulation.

1.3 NPE will achieve the aforementioned by:

(a) Upgrading archaic electromechanical devices to modern electronics with communication provisions;

(b) Establishing a communications network to remotely monitor and control all new electronic devices; and

(c) Automate key electronic devices and systems.

The vast majority of electromechanical devices deployed in NPE's distribution system are nearing end-of-life. Although historically reliable, electromechanical devices are limited in functionality, and do not provide the utility with an ability to remotely monitor or control the distribution system.

Each electronic device added to the distribution system represents an opportunity to improve power quality, efficiency, reliability, security and safety by:

- Enhancing monitoring, control and diagnostics functionality,
- Improving NPE's ability to identify and respond to problems more quickly,
- Introducing system automation,
- Improving the quantity and quality of information available,
- Allowing greater flexibility in system configuration,
- Enabling the ability to implement condition-based maintenance

- Establishing a communications platform capable of supporting real-time system modeling and analysis.

A communications network includes all equipment necessary to facilitate remote monitoring and control of deployed electronic devices. This includes, but is not limited to:

- Communication towers & associated civil infrastructure
- Communications network equipment (routers, switches, antennas etc)
- Required equipment power systems
- Design software for in-house system maintenance, modification and/or expansion
- Network management software
- Cyber-security systems

Automation will be achieved by programming electronic devices to communicate with each other and to monitor the status of various distribution system assets in order to automatically respond to changing conditions within the distribution system. A communications network is required for this to be possible. Development environments will need to be acquired for in-house automation development, created independent from electronic device firmware.

Added-value will be achieved for the customer by:

- Improving operational efficiency,
- Reducing the duration and frequency of outages,
- Establishing a communications platform capable of supporting advanced secondary services,
- Establishing a communications platform capable of dealing with next-generation consumer loads and substantial penetration of green energy, and
- Improving the availability and accuracy of information.

1.4 The practical implementation of 1.3 requires a three-pronged approach, involving:

1) The installation of backup DC power systems;
2) The installation of communications infrastructure;
3) The installation of programmable electronic devices that monitor, protect and control the distribution system.

The backup DC power systems and communications network constitute the backbone of NPE's smart grid. These two fundamental components will enable the continued addition of modern electronic devices that monitor, protect and control the distribution system for the foreseeable future. The DC systems are required to power both the communications network and all electronics devices. It will also provide an uninterrupted power source during system outages.

DC Power Systems

All electronic devices require a power supply . Many only accept DC sources, at various rated voltages (i.e. 12V, 24V, 48V, 125V etc), while others dually accept AC and DC. In order to standardize installation moving forward, NPE will be specifying DC power supplies for all electronic equipment.

AC powered devices are typically installed with backup batteries that offer continued operation for 1-hour when AC supplies fail. Unfortunately, this leads to a rampant dispersion of various battery types and sizes, strewn across the distribution system, requiring maintenance or replacement on a bi-yearly basis. In order to eliminate this inefficiency, NPE will be installing 125Vdc power supplies (rectifiers, chargers and battery banks) at all of its substations. These DC systems will power all local electronic equipment (communications network and distribution system protective devices) and will be sized to provide a minimum of 48-hours backup protection, if operating at full load (much longer if not). This permits NPE to ride out weekend problems and send personnel to site for troubleshooting during normal working hours. Voltages other than 125Vdc will be accommodated by deploying DC-to-DC converters. Station batteries will be stored in a climate controlled environment in order to maximize an expected life of 8 to 10 years.

These power systems are designed and specified in-house with various vendor and manufacturer assistance. Each subsequent order has seen improvements in design from the former and will continue to improve as NPE implements its smart grid plan in the years to come.

Communications Infrastructure

To permit remote monitoring and control, NPE must establish a communications network. To date, none of NPE's distribution substations or electronically controlled field devices are networked. This represents a major operational inefficiency. The most cost-effective solution is to implement a wireless communications network.

As a result, NPE is developing a wireless point-to-multi-point communications network that leverages Industry Canada's allocation of the 1800-1830 MHz frequency band reserved specifically for systems that manage, operate and maintain the electricity supply. This network will provide the backbone upon which a SCADA system can be implemented for real-time monitoring and control of critical assets. It will also enable NPE to:

- Implement transfer trips schemes for distributed generation facilities,
- Enable distributed automation (FDIR/self-healing) using deployed application engines,
- Facilitate the archiving of event history, and
- Provide engineering with invaluable data on asset condition.

Before applying for wireless operating licenses with Industry Canada, NPE will spend considerable time planning for various rollout stages of the communications network. This includes selecting equipment and installation sites, conducting wireless propagation studies, and consulting land use authorities and the general public regarding communications tower siting. Once a license application has been submitted to Industry Canada and approved, NPE will commence all supporting civil works necessary for the installation of required communication towers and associated DC power systems. Communication tower installations require ground grid designs, structural analsysis, lightinng and surge protection design, and procurement and installation logistics planning. Prior to installing network equipment, NPE must develop an IP address plan, network topology designs, physical and cyber security plans, and configuration parameters for router firewalls, AAA servers and VLANs.

The installation of all this equipment represents a significant shift in the knowledge base required to install, operate, maintain and troubleshoot field devices. All rollouts of new equipment will require training of existing staff. Over time it is expected that a requisition for staff skilled in protection and control, SCADA, communications and/or network systems will emerge.

Modern Electronic Devices

The main focus of electronic device deployment will be the upgrade and removal of electromechnical protection devices in NPE's distribution system. This will primarily include feeder protection relays and recloser controllers. Transmission substations will require everything from sync-check and busbar protection to differential and distance relaying. Old RTU's will be replaced with modern data concentrators, capable of implementing web-based HMI interfaces and communication in both DNP3 and IEC 61850 protocols. Where applicable, protection relays will be specified with synchrophasor functionality, to provide real-time measurement of electrical quantities across the distribution system at such a time when NPE can implement GPS satellite-clock synchronization. Applications of synchrophasors may include:

- System model validation,
- Determining stability margins,
- Maximizing stable system loading,
- Islanding detection,
- System-wide disturbance recording (GPS time stamped to facilitate event sequencing and correlation in order to pinpoint problems), and
- Visualization of dynamic system response.

APPENDIX K

NPEI Load Forecast

Niagara Peninsula Energy Weather Normal Load Forecast for 2015 Rate Application

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Weather Normal	2015 Weather Normal
Actual kWh Purchases	1,162,710,674	1,152,043,160	1,205,241,074	1,272,191,339	1,248,057,840	1,283,916,366	1,247,356,069	1,216,807,819	1,264,714,637	1,266,311,662	1,260,789,451	1,250,000,080		
Predicted kWh Purchases with loss	1,162,665,476	1,167,650,716	1,182,645,856	1,271,722,798	1,249,433,262	1,270,377,856	1,255,843,368	1,225,399,085	1,256,450,873	1,265,208,873	1,275,140,355	1,237,576,507	1,238,461,756	1,245,167,213
% Difference	0.0%	1.4%	-1.9%	0.0%	0.1%	-1.1%	0.7%	0.7%	-0.7%	-0.1%	1.1%	-1.0%		
Predicted without loss													1,187,175,763	1,193,603,540
Loss													51,285,993	51,563,673
Loss Factor based on predicted kWh												1250965044	0.043	0.043
												-964,965		
Billed kWh Weather Normalized with CDM	0	1,108,347,420	1,135,405,804	1,208,894,249	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	1,193,712,076	1,232,998,827	1,214,015,314	1,202,305,265	1,184,453,504	1,185,817,112
Loss Factor													1.0432	1.0432
Loss													51,285,993	51,563,673
CDM Difference													2,722,259	7,786,428
By Class														
Residential														
Customers	40,624	42,507	42,859	43,068	43,724	44,325	44,955	45,761	45,840	45,996	45,871	46,274	46,669	47,067
kWh	0	418,838,012	404,285,804	463,562,202	450,017,939	462,721,168	450,470,690	438,952,918	451,343,387	418,849,931	414,592,237	412,298,278	402,178,821	399,166,843
GS<50														
Customers	4,171	3,982	4,033	4,437	4,438	4,339	4,260	4,257	4,357	4,307	4,260	4,315	4,350	4,385
kWh	0	126,366,945	122,937,633	125,194,926	122,020,708	125,994,115	122,663,804	119,930,976	121,294,614	129,680,926	125,465,897	124,179,905	120,510,242	118,740,733
GS>50														
Customers	796	864	819	802	871	853	847	852	851	859	855	863	863	862
kWh	0	553,710,685	598,431,001	609,950,002	601,216,533	622,092,059	605,669,659	592,972,281	611,065,862	675,128,624	664,095,955	655,968,805	651,859,447	657,957,068
kW	1,529,263	1,573,551	1,673,046	1,719,941	1,777,691	1,884,479	1,735,816	1,753,191	1,769,836	1,793,543	1,761,221	1,721,554	1,723,755	1,739,879
Large User														
Customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0
kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0
kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sentinels														
Connections	582	582	602	522	594	569	564	566	417	369	343	337	320	303
kWh	0	298,685	299,222	336,743	317,191	295,243	286,832	294,273	293,544	246,192	267,435	265,619	262,521	259,459
kW	956	968	933	892	831	825	733	695	653	679	721	716	713	705
Streetlights														
Connections	11,157	11,358	11,588	11,752	11,807	11,933	11,986	12,136	12,334	12,540	12,507	12,702	12,845	12,989
kWh	0	6,713,622	7,027,058	7,458,446	8,236,754	7,023,291	7,504,236	7,271,510	7,368,898	7,294,838	7,329,519	7,344,781	7,411,072	7,477,962
kW	17,456	17,588	19,480	19,789	19,932	20,188	20,371	20,319	19,656	20,391	21,037	20,809	20,995	21,184
USL														
Connections	419	422	422	422	422	440	445	454	465	424	384	422	422	422
kWh	0	2,419,471	2,425,087	2,391,930	2,375,520	2,326,944	2,302,512	2,356,161	2,345,772	1,798,316	2,264,271	2,247,877	2,231,402	2,215,047
Total of Above														
Customer/Connections	57,749	59,715	60,323	61,003	61,856	62,459	63,057	64,026	64,264	64,494	64,220	64,913	65,467	66,028
kWh	0	1,108,347,420	1,135,405,804	1,208,894,249	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	1,193,712,076	1,232,998,827	1,214,015,314	1,202,305,265	1,184,453,504	1,185,817,112
kW from applicable classes	1,547,675	1,592,107	1,693,459	1,740,622	1,798,454	1,905,492	1,756,920	1,774,205	1,790,145	1,814,614	1,782,980	1,743,079	1,745,463	1,761,769
Total from Model														
Customer/Connections		59,715	60,323	61,003	61,856	62,459	63,057	64,026	64,264	64,494	64,220	64,913	65,467	66,028
kWh		1,108,347,420	1,135,405,804	1,208,894,249	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	1,193,712,076	1,232,998,827	1,214,015,314	1,202,305,265	1,184,453,504	1,185,817,112
kW from applicable classes		1,592,107	1,693,459	1,740,622	1,798,454	1,905,492	1,756,920	1,774,205	1,790,145	1,814,614	1,782,980	1,743,079	1,745,463	1,761,769
Check should all be zero														
Customer/Connections		0	0	0	0	0	0	0	0	0	0	0	0	0
kWh		0	0	0	0	0	0	0	0	0	0	0	0	0
kW from applicable classes		0	0	0	0	0	0	0	0	0	0	0	0	0

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Actual	1,163	1,152	1,205	1,272	1,248	1,284	1,247	1,217	1,265	1,266	1,261	1,250
Predicted	1,163	1,168	1,183	1,272	1,249	1,270	1,256	1,225	1,256	1,265	1,275	1,238

Drivers of Differences 2015 over 2014 Predicted kWh

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	2015 Predicted kWh	109,038,541	99,036,480	101,214,362	94,276,684	95,533,401	104,580,956	122,777,933	120,149,624	97,177,619	96,208,205	96,199,958	108,973,451	1,245,167,213
	2014 Predicted kWh	109,590,615	99,458,924	101,420,362	94,266,240	95,306,514	104,137,624	122,118,157	119,273,405	96,084,955	94,899,097	94,674,406	107,231,456	1,238,461,756
	Difference (kWh)	-552,074	-422,444	-206,000	10,444	226,888	443,332	659,776	876,220	1,092,663	1,309,107	1,525,551	1,741,995	6,705,457
HDD	2015 value	626	568	501	325	174	33	1	2	30	203	361	551	3,375
	2014 value	626	568	501	325	174	33	1	2	30	203	361	551	3,375
	Difference	0	0	0	0	0	0	0	0	0	0	0	0	0
	Regression Coefficient	23,655	23,655	23,655	23,655	23,655	23,655	23,655	23,655	23,655	23,655	23,655	23,655	
	Impact on forecast (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
CDD	2015 value	0	0	0	0	9	61	143	129	47	5	0	0	395
	2014 value	0	0	0	0	9	61	143	129	47	5	0	0	395
	Difference	0	0	0	0	0	0	0	0	0	0	0	0	0
	Regression Coefficient	192,327	192,327	192,327	192,327	192,327	192,327	192,327	192,327	192,327	192,327	192,327	192,327	
	Impact on forecast (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
GDP	2015 value	150	150	150	151	151	151	151	152	152	152	153	153	1,815
	2014 value	146	147	147	147	147	148	148	148	148	149	149	149	1,773
	Difference	3	3	3	3	3	3	3	4	4	4	4	4	42
	Regression Coefficient	321,215	321,215	321,215	321,215	321,215	321,215	321,215	321,215	321,215	321,215	321,215	321,215	
	Impact on forecast (kWh)	1,084,395	1,090,459	1,096,523	1,102,586	1,108,650	1,114,714	1,120,777	1,126,841	1,132,905	1,138,968	1,145,032	1,151,096	13,412,946
# Days in Month	2015 value	31	28	31	30	31	30	31	31	30	31	30	31	365
	2014 value	31	28	31	30	31	30	31	31	30	31	30	31	365
	Difference	0	0	0	0	0	0	0	0	0	0	0	0	0
	Regression Coefficient	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	2,930,932	
	Impact on forecast (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
CDM kWh Savec	2015 value	2,569,725	2,569,980	2,570,488	2,570,997	2,571,505	2,572,014	2,572,522	2,573,031	2,573,540	2,574,048	2,574,557	2,575,065	30,867,473
	2014 value	2,124,895	2,148,417	2,188,542	2,228,666	2,268,791	2,308,916	2,349,040	2,389,165	2,429,289	2,469,414	2,509,538	2,549,663	27,964,336
	Difference	444,831	421,562	381,946	342,330	302,714	263,098	223,482	183,866	144,250	104,634	65,018	25,402	2,903,137
	Regression Coefficient	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	
	Impact on forecast (kWh)	-2,362,268	-2,238,701	-2,028,321	-1,817,941	-1,607,561	-1,397,180	-1,186,800	-976,420	-766,039	-555,659	-345,279	-134,898	(15,417,067)
Spring/Fall	2015 value	0	0	1	1	1	0	0	0	1	1	1	0	6
	2014 value	0	0	1	1	1	0	0	0	1	1	1	0	6
	Difference	0	0	0	0	0	0	0	0	0	0	0	0	0
	Regression Coefficient	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	-5,190,218	
	Impact on forecast (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Population	2015 value	136,626	136,672	136,717	136,763	136,809	136,855	136,901	136,946	136,992	137,038	137,084	137,130	1,642,533
	2014 value	136,076	136,122	136,168	136,214	136,259	136,305	136,351	136,397	136,443	136,488	136,534	136,580	1,635,938
	Difference	550	550	550	550	550	550	550	550	550	550	550	550	6,595
	Regression Coefficient	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	1,321	
	Impact on forecast (kWh)	725,798	725,798	725,798	725,798	725,798	725,798	725,798	725,798	725,798	725,798	725,798	725,798	8,709,577
Peak Hours	2015 value	320	304	368	320	320	352	336	336	336	320	336	368	4,016
	2014 value	320	304	368	320	320	352	336	336	336	320	336	368	4,016
	Difference	0	0	0	0	0	0	0	0	0	0	0	0	0
	Regression Coefficient	0	0	0	0	0	0	0	0	0	0	0	0	
	Impact on forecast (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Impact on Forecast (kWh)		-552,074	-422,444	-206,000	10,444	226,888	443,332	659,776	876,220	1,092,663	1,309,107	1,525,551	1,741,995	6,705,457

	Purchased	Embedded Generation	Load Transfers	Total	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Updated CDM kWh Saved in month	Spring Fall Flag	0.0563 Population	Number of Peak Hours	2011 Rate App CDM kWh Saved in month	Predicted Purchases
Jan-96	0			0	719.20	0.00	94.72	31		0	119,961	352		85,253,160
Feb-96	0			0	648.20	0.00	94.80	29		0	120,043	336		77,847,160
Mar-96	0			0	618.50	0.00	94.89	31		1	120,124	336		77,951,661
Apr-96	0			0	360.60	0.00	94.97	30		1	120,206	336		69,055,459
May-96	0			0	240.40	3.20	95.06	31		1	120,288	352		69,893,931
Jun-96	0			0	37.30	21.90	95.14	30		0	120,369	320		71,080,817
Jul-96	0			0	2.60	72.10	95.23	31		0	120,451	352		82,981,221
Aug-96	0			0	0.40	115.40	95.32	31		0	120,533	336		91,392,464
Sep-96	0			0	56.00	34.80	95.40	30		1	120,615	320		69,220,596
Oct-96	0			0	228.30	1.40	95.49	31		1	120,696	352		69,939,228
Nov-96	0			0	468.90	0.00	95.57	30		1	120,778	320		72,566,133
Dec-96	0			0	496.20	0.00	95.66	31		0	120,860	320		81,468,717
Jan-97	0			0	606.30	0.00	96.01	31		0	120,948	352		84,303,279
Feb-97	0			0	503.80	0.00	96.37	28		0	121,036	320		73,316,340
Mar-97	0			0	500.50	0.00	96.73	31		1	121,124	304		77,071,809
Apr-97	0			0	320.90	0.00	97.08	30		1	121,212	352		70,123,755
May-97	0			0	259.30	0.00	97.44	31		1	121,300	336		71,829,322
Jun-97	0			0	39.40	64.40	97.81	30		0	121,388	336		81,504,863
Jul-97	0			0	9.70	94.10	98.17	31		0	121,476	352		89,677,993
Aug-97	0			0	9.00	58.50	98.53	31		0	121,564	320		83,047,701
Sep-97	0			0	48.70	18.30	98.90	30		1	121,652	336		68,367,666
Oct-97	0			0	221.50	2.10	99.26	31		1	121,740	352		72,504,512
Nov-97	0			0	384.90	0.00	99.63	30		1	121,828	304		73,269,374
Dec-97	0			0	490.00	0.00	100.00	31		0	121,916	336		84,111,536
Jan-98	0			0	524.90	0.00	100.39	31		0	122,004	336		85,179,468
Feb-98	0			0	462.90	0.00	100.79	28		0	122,092	320		75,162,895
Mar-98	0			0	462.30	5.50	101.18	31		1	122,180	352		80,052,428
Apr-98	0			0	258.90	0.00	101.58	30		1	122,268	336		71,496,053
May-98	0			0	107.60	16.80	101.98	31		1	122,357	320		74,323,370
Jun-98	0			0	47.60	92.20	102.38	30		0	122,445	352		89,909,614
Jul-98	0			0	0.00	127.80	102.78	31		0	122,533	352		98,806,738
Aug-98	0			0	0.00	135.60	103.18	31		0	122,621	320		100,552,751
Sep-98	0			0	14.10	64.00	103.59	30		1	122,709	336		79,240,932
Oct-98	0			0	157.00	0.30	104.00	31		1	122,797	336		73,547,895
Nov-98	0			0	340.50	0.00	104.40	30		1	122,885	336		75,147,419
Dec-98	0			0	466.20	0.00	104.81	31		0	122,973	336		86,489,959
Jan-99	0			0	671.90	0.00	105.45	31		0	123,061	320		91,675,983
Feb-99	0			0	502.70	0.00	106.09	28		0	123,149	320		79,202,055
Mar-99	0			0	517.70	0.00	106.73	31		1	123,237	368		83,482,057
Apr-99	0			0	312.50	0.00	107.38	30		1	123,325	336		76,020,892
May-99	0			0	137.30	14.10	108.03	31		1	123,413	320		77,844,313
Jun-99	0			0	17.70	72.60	108.68	30		0	123,501	352		88,851,890
Jul-99	0			0	0.20	184.10	109.34	31		0	123,589	336		113,140,905
Aug-99	0			0	1.60	91.00	110.00	31		0	123,677	336		95,597,334
Sep-99	0			0	25.20	59.60	110.67	30		1	123,765	336		82,325,599
Oct-99	0			0	201.00	1.00	111.34	31		1	123,853	320		78,476,303
Nov-99	0			0	322.10	0.00	112.01	30		1	123,941	352		78,550,510
Dec-99	0			0	516.00	0.00	112.69	31		0	124,029	336		91,592,546
Jan-00	0			0	662.50	0.00	113.21	31		0	124,117	320		95,340,615
Feb-00	0			0	542.50	0.00	113.73	29		0	124,205	336		86,923,433
Mar-00	0			0	426.90	0.00	114.25	31		1	124,293	368		85,144,612
Apr-00	0			0	337.10	0.00	114.77	30		1	124,381	304		80,374,293
May-00	0			0	149.20	0.00	115.30	31		1	124,469	352		79,146,022
Jun-00	0			0	44.80	33.10	115.83	30		0	124,557	352		85,588,115
Jul-00	0			0	0.20	83.70	116.36	31		0	124,645	320		97,482,941
Aug-00	0			0	2.80	109.10	116.90	31		0	124,733	352		102,717,523
Sep-00	0			0	60.30	50.30	117.43	30		1	124,821	320		84,936,522
Oct-00	0			0	196.60	0.00	117.97	31		1	124,910	336		81,707,214
Nov-00	0			0	376.80	0.00	118.52	30		1	124,998	352		83,329,335
Dec-00	0			0	628.60	0.00	119.06	31		0	125,086	304		97,698,061
Jan-01	0			0	621.50	0.00	119.23	31		0	125,174	352		97,701,793
Feb-01	0			0	530.30	0.00	119.40	28		0	125,262	320		86,923,394
Mar-01	0			0	520.50	0.00	119.58	31		1	125,350	352		90,465,995
Apr-01	0			0	322.80	0.00	119.75	30		1	125,438	320		83,030,326
May-01	0			0	129.40	2.20	119.92	31		1	125,526	352		81,981,439
Jun-01	0			0	27.70	61.00	120.10	30		0	125,614	336		93,315,868
Jul-01	0			0	1.80	91.00	120.27	31		0	125,702	336		101,576,092
Aug-01	0			0	0.00	0.00	120.45	31		0	125,790	352		84,204,042

SUMMARY OUTPUT

Regression Stai
Multiple R
R Square
Adjusted R Square
Standard Error
Observations

ANOVA

Regression
Residual
Total

Intercept
Heating Degree Days
Cooling Degree Days
Ontario Real GDP Monthly %
Number of Days in Month
CDM kWh Saved in month
Spring Fall Flag
Population

	Purchased	Embedded Generation	Load Transfers	Total	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Updated CDM kWh Saved in month	Spring Fall Flag	0.0563 Population	Number of Peak Hours	2011 Rate App CDM kWh Saved in month	Predicted Purchases	SUMMARY OUTPUT
Sep-01	0			0	43.60	45.20	120.62	30		1	125,878	304		85,979,757	
Oct-01	0			0	184.90	3.80	120.80	31		1	125,966	352		84,463,280	
Nov-01	0			0	290.40	0.00	120.97	30		1	126,054	352		83,469,639	
Dec-01	0			0	455.00	0.00	121.15	31		0	126,144	304		95,659,675	
Jan-02	98,398,774			98,398,774	530.30	0.00	121.50	31	0	0	126,248	352		97,692,694	
Feb-02	87,515,454			87,515,454	492.30	0.00	121.86	28	0	0	126,351	320		88,253,106	
Mar-02	94,028,461			94,028,461	513.50	0.00	122.22	31	0	1	126,455	320		92,609,630	
Apr-02	86,184,466			86,184,466	314.10	0.00	122.59	30	0	1	126,558	352		85,214,616	
May-02	85,447,299			85,447,299	224.50	2.40	122.95	31	0	1	126,662	352		86,740,751	
Jun-02	95,651,673			95,651,673	39.30	54.80	123.31	30	0	0	126,765	320		94,950,462	
Jul-02	119,450,096			119,450,096	0.00	191.60	123.68	31	0	0	126,869	352		123,515,844	
Aug-02	114,483,163			114,483,163	0.00	155.00	124.04	31	0	0	126,972	336		116,730,864	
Sep-02	96,936,653			96,936,653	9.80	92.30	124.41	30	0	1	127,076	320		97,037,179	
Oct-02	90,917,731			90,917,731	234.60	11.40	124.78	31	0	1	127,179	352		89,981,481	
Nov-02	90,920,618			90,920,618	381.20	0.00	125.14	30	0	1	127,283	336		88,581,118	
Dec-02	102,776,286			102,776,286	567.20	0.00	125.51	31	0	0	127,386	320		101,357,731	
Jan-03	104,493,535			104,493,535	707.70	0.00	125.66	31	0	0	127,490	352		104,864,772	
Feb-03	96,011,347			96,011,347	625.70	0.00	125.81	28	0	0	127,593	320		94,315,757	
Mar-03	95,684,640			95,684,640	547.70	0.00	125.95	31	0	1	127,697	336		96,256,792	
Apr-03	86,343,957			86,343,957	398.30	0.00	126.10	30	0	1	127,800	336		89,975,379	
May-03	84,100,206			84,100,206	235.40	0.00	126.24	31	0	1	127,904	336		89,236,537	
Jun-03	90,485,413			90,485,413	74.10	44.60	126.39	30	0	0	128,007	336		96,441,719	
Jul-03	107,838,219			107,838,219	3.40	105.00	126.54	31	0	0	128,111	352		109,500,535	
Aug-03	111,720,633			111,720,633	0.00	143.50	126.68	31	0	0	128,215	320		117,008,526	
Sep-03	90,994,824			90,994,824	26.80	27.40	126.83	30	0	1	128,318	336		87,376,123	
Oct-03	90,574,201			90,574,201	245.30	0.00	126.98	31	0	1	128,422	352		90,389,955	
Nov-03	91,660,392			91,660,392	348.00	0.00	127.12	30	0	1	128,525	320		90,072,437	
Dec-03	102,135,791			102,135,791	510.10	0.00	127.27	31	0	0	128,629	336		102,212,184	
Jan-04	110,906,403			110,906,403	750.20	0.00	127.53	31	0	0	128,732	336		108,112,770	
Feb-04	98,773,310			98,773,310	578.90	0.00	127.80	29	0	0	128,836	320		98,419,855	
Mar-04	100,169,246			100,169,246	479.80	0.00	128.06	31	0	1	128,939	368		96,968,541	
Apr-04	89,485,333			89,485,333	332.50	0.50	128.32	30	0	1	129,043	336		90,870,798	
May-04	90,686,143			90,686,143	169.70	1.20	128.59	31	0	1	129,146	320		90,306,901	
Jun-04	96,517,444			96,517,444	45.60	26.30	128.85	30	0	0	129,250	352		94,679,765	
Jul-04	110,297,642			110,297,642	1.90	79.30	129.12	31	0	0	129,353	336		106,992,251	
Aug-04	109,063,695			109,063,695	1.80	85.00	129.38	31	0	0	129,457	336		108,308,306	
Sep-04	103,094,592			103,094,592	14.60	65.30	129.65	30	0	1	129,560	336		96,923,445	
Oct-04	93,329,246			93,329,246	196.40	2.60	129.92	31	0	1	129,664	320		92,318,553	
Nov-04	94,434,399			94,434,399	341.00	0.00	130.19	30	0	1	129,767	352		92,530,823	
Dec-04	108,483,621			108,483,621	566.70	0.00	130.45	31	0	0	129,871	336		106,213,850	
Jan-05	111,357,551			111,357,551	693.30	0.00	130.74	31	0	0	129,974	320	64,076	109,438,481	
Feb-05	97,354,644			97,354,644	582.00	0.00	131.03	28	0	0	130,078	320	64,076	98,242,916	
Mar-05	103,696,307			103,696,307	576.10	0.00	131.33	31	0	1	130,182	352	64,076	101,936,206	
Apr-05	91,002,648			91,002,648	345.10	0.00	131.62	30	0	1	130,285	336	64,076	93,771,375	
May-05	90,914,555			90,914,555	215.30	0.00	131.91	31	0	1	130,389	336	64,076	93,862,538	
Jun-05	117,110,314			117,110,314	10.40	107.80	132.20	30	0	0	130,492	352	64,076	112,238,553	
Jul-05	130,492,623			130,492,623	0.00	183.50	132.50	31	0	0	130,596	320	64,076	129,713,705	
Aug-05	125,304,430			125,304,430	0.00	165.70	132.79	31	0	0	130,699	352	64,076	126,521,615	
Sep-05	103,515,709			103,515,709	7.30	76.60	133.09	30	0	1	130,803	336	64,076	101,668,383	
Oct-05	95,683,703			95,683,703	216.60	13.40	133.38	31	0	1	130,906	320	64,076	97,627,082	
Nov-05	95,832,424			95,832,424	369.30	0.00	133.68	30	0	1	131,010	352	64,076	95,963,100	
Dec-05	109,926,431			109,926,431	640.80	0.00	133.98	31	0	0	131,113	320	64,076	110,738,844	
Jan-06	105,189,786			105,189,786	520.40	0.00	134.25	31	13,498	0	131,217	336	348,241	108,044,434	
Feb-06	97,673,987			97,673,987	564.70	0.00	134.53	28	40,493	0	131,320	320	348,241	100,381,767	
Mar-06	102,138,407			102,138,407	488.70	0.00	134.81	31	67,488	1	131,424	368	348,241	102,268,919	
Apr-06	89,654,385			89,654,385	296.70	0.00	135.08	30	94,484	1	131,527	304	348,241	94,878,724	
May-06	96,375,371			96,375,371	135.30	29.20	135.36	31	121,479	1	131,631	352	348,241	99,690,366	
Jun-06	106,149,796			106,149,796	15.90	65.60	135.64	30	148,474	0	131,734	352	348,241	106,208,823	
Jul-06	129,944,898			129,944,898	0.60	166.80	135.92	31	175,470	0	131,838	320	348,241	128,324,395	
Aug-06	120,333,539			120,333,539	1.40	103.80	136.20	31	202,465	0	131,941	352	348,241	116,310,045	
Sep-06	95,914,535			95,914,535	45.90	17.00	136.48	30	229,460	1	132,045	320	348,241	92,631,096	
Oct-06	99,436,287			99,436,287	234.40	0.40	136.76	31	256,456	1	132,149	336	348,241	96,912,111	
Nov-06	98,699,343			98,699,343	341.90	0.00	137.04	30	283,451	1	132,252	352	348,241	96,531,056	
Dec-06	106,547,506			106,547,506	445.20	0.00	137.33	31	296,949	0	132,356	304	348,241	107,251,527	
Jan-07	110,076,804			110,076,804	578.00	0.00	137.57	31	308,453	0	132,252	352	655,465	110,275,202	
Feb-07	106,214,903			106,214,903	657.80	0.00	137.82	28	331,461	0	132,356	320	655,465	103,464,856	
Mar-07	105,901,314			105,901,314	515.50	0.00	138.07	31	354,470	1	132,400	352	655,465	103,718,162	
Apr-07	96,871,140			96,871,140	362.10	0.00	138.33	30	377,478	1	132,445	320	655,465	97,175,531	

									Updated		0.0563		2011 Rate App		
	Purchased	Embedded Generation	Load Transfers	Total	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	CDM kWh Saved in month	Spring Fall Flag	Population	Number of Peak Hours	CDM kWh Saved in month	Predicted Purchases	SUMMARY OUTPUT
May-07	96,387,835			96,387,835	157.90	13.60	138.58	31	400,487	1	132,489	352	655,465	97,908,860	
Jun-07	113,036,516			113,036,516	10.90	81.70	138.83	30	423,495	0	132,533	336	655,465	109,805,575	
Jul-07	116,239,482			116,239,482	0.00	109.00	139.08	31	446,504	0	132,578	336	655,465	117,746,649	
Aug-07	124,879,950			124,879,950	6.80	142.50	139.33	31	469,512	0	132,622	352	655,465	124,368,063	
Sep-07	104,023,176			104,023,176	19.20	54.70	139.59	30	492,521	1	132,667	304	655,465	99,671,729	
Oct-07	99,226,202			99,226,202	103.00	20.60	139.84	31	515,529	1	132,711	352	655,465	98,044,554	
Nov-07	100,079,144			100,079,144	385.40	0.00	140.09	30	538,538	1	132,756	352	655,465	97,850,024	
Dec-07	110,979,900			110,979,900	567.10	0.00	140.35	31	550,042	0	132,800	304	655,465	110,348,651	
Jan-08	109,593,071		(82,212)	109,510,859	562.40	0.00	140.30	31	555,158	0	132,845	352	906,713	110,253,962	
Feb-08	104,778,875		(82,212)	104,696,663	599.90	0.00	140.25	29	565,390	0	132,889	320	906,713	105,268,501	
Mar-08	105,424,609		(82,212)	105,342,397	548.00	0.00	140.21	31	575,622	1	132,934	304	906,713	104,701,766	
Apr-08	86,811,986		(82,212)	86,729,774	303.30	0.00	140.16	30	585,854	1	132,978	352	906,713	95,971,708	
May-08	95,673,539		(82,212)	95,591,327	192.70	0.00	140.11	31	596,086	1	133,022	336	906,713	96,275,702	
Jun-08	106,441,284		(82,212)	106,359,072	30.40	62.50	140.07	30	606,318	0	133,067	336	906,713	106,705,484	
Jul-08	120,363,654		(82,212)	120,281,441	0.00	115.40	140.02	31	616,550	0	133,111	352	906,713	119,080,723	
Aug-08	112,977,083		(82,212)	112,894,871	4.50	85.70	139.97	31	626,782	0	133,156	320	906,713	113,464,430	
Sep-08	101,476,765		(82,212)	101,394,552	38.60	39.60	139.93	30	637,014	1	133,200	336	906,713	97,273,034	
Oct-08	95,543,325		(82,212)	95,461,113	207.10	0.40	139.88	31	647,246	1	133,245	352	906,713	96,640,057	
Nov-08	97,619,273		(82,212)	97,537,061	420.90	0.00	139.83	30	657,478	1	133,289	304	906,713	98,679,080	
Dec-08	111,639,154		(82,212)	111,556,941	620.10	0.00	139.79	31	662,594	0	133,334	336	906,713	111,528,922	
Jan-09	117,706,103		(61,304)	117,644,799	723.90	0.00	139.39	31	674,484	0	133,378	336	912,482	113,852,701	
Feb-09	97,637,232		(61,304)	97,575,928	537.00	0.00	138.99	28	698,263	0	133,423	304	912,482	100,444,296	
Mar-09	102,033,201		(61,304)	101,971,897	509.10	0.00	138.60	31	722,042	1	133,467	352	912,482	103,192,824	
Apr-09	92,234,007		(61,304)	92,172,703	315.40	0.00	138.21	30	745,822	1	133,511	320	912,482	95,486,144	
May-09	90,740,353		(61,304)	90,679,049	185.90	0.00	137.82	31	769,601	1	133,556	320	912,482	95,160,359	
Jun-09	97,871,861		(61,304)	97,810,557	66.80	33.00	137.43	30	793,380	0	133,600	352	912,482	100,756,078	
Jul-09	106,379,010		(61,304)	106,317,706	0.60	56.80	137.04	31	817,160	0	133,645	352	912,482	106,505,760	
Aug-09	118,375,480		(61,304)	118,314,176	3.90	118.80	136.65	31	840,939	0	133,689	320	912,482	118,315,788	
Sep-09	96,821,587		(61,304)	96,760,283	32.40	30.70	136.26	30	864,718	1	133,734	336	912,482	93,732,912	
Oct-09	93,959,689		(61,304)	93,898,385	241.20	0.00	135.87	31	888,498	1	133,778	336	912,482	95,507,077	
Nov-09	93,794,433		(61,304)	93,733,129	320.80	0.00	135.49	30	912,277	1	133,823	320	912,482	94,267,884	
Dec-09	109,990,512		(61,304)	109,929,208	570.89	0.00	135.11	31	924,167	0	133,867	352	912,482	108,177,264	
Jan-10	112,413,953	411,293	(96,502)	112,728,743	653.30	0.00	135.41	31	927,755	0	133,912	320	1,109,507	110,264,006	
Feb-10	98,822,728	532,219	(96,502)	99,258,445	551.10	0.00	135.71	28	934,931	0	133,956	304	1,109,507	99,172,103	
Mar-10	99,590,880	545,833	(96,502)	100,040,210	434.70	0.00	136.02	31	942,107	1	134,000	368	1,109,507	100,139,889	
Apr-10	88,866,064	587,674	(96,502)	89,357,236	253.20	0.00	136.33	30	949,284	1	134,045	320	1,109,507	93,034,422	
May-10	97,708,833	438,525	(96,502)	98,050,856	129.40	22.40	136.63	31	956,460	1	134,089	320	1,109,507	97,464,069	
Jun-10	106,489,650	575,982	(96,502)	106,969,130	15.00	60.60	136.94	30	963,636	0	134,134	352	1,109,507	104,483,413	
Jul-10	129,819,711	468,792	(96,502)	130,192,001	1.90	174.60	137.25	31	970,813	0	134,178	336	1,109,507	129,149,267	
Aug-10	125,064,295	467,603	(96,502)	125,435,396	1.40	145.70	137.56	31	977,989	0	134,223	336	1,109,507	123,699,000	
Sep-10	98,983,964	627,245	(96,502)	99,514,707	54.40	40.20	137.87	30	985,165	1	134,267	336	1,109,507	96,661,149	
Oct-10	93,865,161	384,107	(96,502)	94,152,765	218.20	0.50	138.18	31	992,342	1	134,312	320	1,109,507	95,951,707	
Nov-10	96,656,392	560,522	(96,502)	97,120,412	346.60	0.00	138.49	30	999,518	1	134,356	336	1,109,507	96,082,428	
Dec-10	111,304,958	686,277	(96,502)	111,894,733	600.50	0.00	138.80	31	1,003,106	0	134,401	368	1,109,507	110,349,420	
Jan-11	113,431,520	490,789	(92,424)	113,829,885	678.00	0.00	139.24	31	1,014,757	0	134,445	320	1,169,147	112,321,926	
Feb-11	101,615,469	597,207	(92,424)	102,120,252	578.50	0.00	139.45	28	1,038,058	0	134,490	304	1,169,147	101,177,386	
Mar-11	105,339,679	1,602,527	(92,424)	106,849,783	527.00	0.00	139.66	31	1,061,359	1	134,534	368	1,169,147	103,563,676	
Apr-11	93,360,769	818,684	(92,424)	94,087,029	342.60	0.00	139.87	30	1,084,661	1	134,578	320	1,169,147	96,272,661	
May-11	94,535,391	868,682	(92,424)	95,311,649	187.10	4.10	140.08	31	1,107,962	1	134,623	320	1,169,147	96,315,689	
Jun-11	103,622,683	951,129	(92,424)	104,481,388	21.90	41.80	140.29	30	1,131,263	0	134,667	352	1,169,147	101,919,787	
Jul-11	131,926,638	481,410	(92,424)	132,315,624	0.00	196.90	140.49	31	1,154,564	0	134,712	336	1,169,147	134,164,484	
Aug-11	120,223,938	847,595	(92,424)	120,979,110	0.00	146.30	140.70	31	1,177,866	0	134,756	336	1,169,147	124,434,721	
Sep-11	100,218,739	1,330,377	(92,424)	101,456,692	26.90	39.90	140.91	30	1,201,167	1	134,801	336	1,169,147	96,488,314	
Oct-11	94,403,706	890,902	(92,424)	95,202,185	184.90	4.20	141.12	31	1,224,468	1	134,845	320	1,169,147	96,292,694	
Nov-11	93,722,005	809,920	(92,424)	94,439,501	284.90	0.00	141.33	30	1,247,769	1	134,890	336	1,169,147	94,921,488	
Dec-11	104,372,807	958,180	(92,424)	105,238,563	463.70	0.00	141.54	31	1,259,420	0	134,934	368	1,169,147	107,336,048	
Jan-12	108,352,391	950,033	(78,846)	109,223,578	554.40	0.00	141.73	31	1,276,419	0	134,979	320	0	109,510,645	
Feb-12	98,705,242	947,209	(78,846)	99,573,605	482.40	0.00	141.91	29	1,310,418	0	135,023	304	0	101,884,379	
Mar-12	96,296,941	722,234	(78,846)	96,940,329	366.70	0.00	142.10	31	1,344,417	1	135,069	368	0	99,759,652	
Apr-12	89,872,581	601,702	(78,846)	90,395,437	296.30	0.00	142.29	30	1,378,416	1	135,115	320	0	95,103,935	
May-12	98,707,869	1,571,841	(78,846)	100,200,864	99.50	22.40	142.48	31	1,412,414	1	135,160	320	0	97,628,162	
Jun-12	109,390,923	1,115,019	(78,846)	110,427,096	18.90	105.60	142.67	30	1,446,413	0	135,206	352	0	113,922,951	
Jul-12	133,058,609	1,039,699	(78,846)	134,019,462	0.00	203.50	142.86	31	1,480,412	0	135,252	336	0	135,176,122	
Aug-12	121,123,046	1,093,336	(78,846)	122,137,537	0.00	148.70	143.05	31	1,514,411	0	135,298	336	0	124,577,176	
Sep-12	99,680,085	646,474	(78,846)	100,247,713	37.90	50.30	143.23	30	1,548,409	1	135,344	336	0	98,368,179	
Oct-12	94,333,164	944,121	(78,846)	95,198,440	191.90	2.60	143.42	31	1,582,408	1	135,389	320	0	95,708,608	
Nov-12	96,179,067	931,868	(78,846)	97,032,089	381.90	0.00	143.61	30	1,616,407	1	135,435	336	0	96,712,694	
Dec-12	104,482,420	989,725	(78,846)	105,393,299	463.20	0.00	143.80	31	1,633,406	0	135,481	368	0	106,787,851	

	Purchased	Embedded Generation	Load Transfers	Total	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Updated CDM kWh Saved in month	Spring Fall Flag	0.0563 Population	Number of Peak Hours	2011 Rate App CDM kWh Saved in month	Predicted Purchases	SUMMARY OUTPUT
Jan-13	109,467,098	930,414	(80,414)	110,317,098	556.40	0.00	143.98	31	1,655,904	0	135,527	320	0	108,991,277	
Feb-13	98,965,962	906,712	(80,414)	99,792,260	565.90	0.00	144.16	28	1,700,899	0	135,573	304	0	100,302,482	
Mar-13	102,422,656	894,061	(80,414)	103,236,304	508.70	0.00	144.34	31	1,745,895	1	135,618	368	0	102,431,249	
Apr-13	92,083,367	1,022,778	(80,414)	93,025,731	341.30	0.00	144.52	30	1,790,890	1	135,664	320	0	95,419,687	
May-13	95,266,526	1,234,580	(80,414)	96,420,692	153.90	14.30	144.70	31	1,835,885	1	135,710	320	0	96,547,152	
Jun-13	101,746,391	1,118,148	(80,414)	102,784,126	44.30	47.50	144.88	30	1,880,881	0	135,756	352	0	102,478,331	
Jul-13	123,815,621	1,104,432	(80,414)	124,839,640	2.30	139.40	145.06	31	1,925,876	0	135,802	336	0	121,969,826	
Aug-13	114,328,198	1,270,351	(80,414)	115,518,135	0.00	106.40	145.24	31	1,970,871	0	135,847	336	0	115,447,917	
Sep-13	96,921,113	1,399,910	(80,414)	98,240,610	51.60	34.40	145.42	30	2,015,867	1	135,893	336	0	94,579,143	
Oct-13	94,790,916	1,226,455	(80,414)	95,936,957	161.40	4.80	145.60	31	2,060,862	1	135,939	320	0	94,293,840	
Nov-13	98,272,590	1,105,762	(80,414)	99,297,938	412.90	0.00	145.78	30	2,105,857	1	135,985	336	0	96,268,335	
Dec-13	109,815,032	855,971	(80,414)	110,590,590	601.40	0.00	145.96	31	2,128,355	0	136,031	368	0	108,847,267	
Jan-14	117,246,823	771,851		118,018,674	625.69	0.00	146.24	31	2,124,895	0	136,076	320		109,590,615	
Feb-14	101,962,544	811,223		102,773,767	568.02	0.00	146.52	28	2,148,417	0	136,122	304		99,458,924	
Mar-14	106,897,420	920,445		107,817,865	501.29	0.00	146.80	31	2,188,542	1	136,168	368		101,420,362	
Apr-14	88,321,885	1,137,316		89,459,201	325.08	0.04	147.08	30	2,228,666	1	136,214	320		94,266,240	
May-14	0			0	173.88	9.13	147.36	31	2,268,791	1	136,259	320		95,306,514	
Jun-14	0			0	32.79	60.98	147.64	30	2,308,916	0	136,305	352		104,137,624	
Jul-14	0			0	0.89	143.48	147.92	31	2,349,040	0	136,351	336		122,118,157	
Aug-14	0			0	1.65	128.93	148.20	31	2,389,165	0	136,397	336		119,273,405	
Sep-14	0			0	30.45	47.37	148.48	30	2,429,289	1	136,443	336		96,084,955	
Oct-14	0			0	202.92	5.08	148.76	31	2,469,414	1	136,488	320		94,899,097	
Nov-14	0			0	361.23	0.00	149.04	30	2,509,538	1	136,534	336		94,674,406	
Dec-14	0			0	551.41	0.00	149.32	31	2,549,663	0	136,580	368		107,231,456	
Jan-15	0			0	625.69	0.00	149.61	31	2,569,725	0	136,626	320		109,038,541	
Feb-15	0			0	568.02	0.00	149.91	28	2,569,980	0	136,672	304		99,036,480	
Mar-15	0			0	501.29	0.00	150.21	31	2,570,488	1	136,717	368		101,214,362	
Apr-15	0			0	325.08	0.04	150.51	30	2,570,997	1	136,763	320		94,276,684	
May-15	0			0	173.88	9.13	150.81	31	2,571,505	1	136,809	320		95,533,401	
Jun-15	0			0	32.79	60.98	151.11	30	2,572,014	0	136,855	352		104,580,956	
Jul-15	0			0	0.89	143.48	151.41	31	2,572,522	0	136,901	336		122,777,933	
Aug-15	0			0	1.65	128.93	151.70	31	2,573,031	0	136,946	336		120,149,624	
Sep-15	0			0	30.45	47.37	152.00	30	2,573,540	1	136,992	336		97,177,619	
Oct-15	0			0	202.92	5.08	152.30	31	2,574,048	1	137,038	320		96,208,205	
Nov-15	0			0	361.23	0.00	152.60	30	2,574,557	1	137,084	336		96,199,958	
Dec-15	0			0	551.41	0.00	152.90	31	2,575,065	0	137,130	368		108,973,451	

Weather Normal — 23,307,352,587

	Purchased	Embedded Generation	Load Transfers	Total	Predicted Purchases
1996	0	0	0	0	918,650,549
1997	0	0	0	0	929,128,148
1998	0	0	0	0	989,909,522
1999	0	0	0	0	1,036,760,387
2000	0	0	0	0	1,060,388,686
2001	0	0	0	0	1,068,771,300
2002	1,162,710,674	0	0	1,162,710,674	1,162,665,476
2003	1,152,043,160	0	0	1,152,043,160	1,167,650,716
2004	1,205,241,074	0	0	1,205,241,074	1,182,645,856
2005	1,272,191,339	0	0	1,272,191,339	1,271,722,798
2006	1,248,057,840	0	0	1,248,057,840	1,249,433,262
2007	1,283,916,366	0	0	1,283,916,366	1,270,377,856
2008	1,248,342,618	0	-986,549	1,247,356,069	1,255,843,368
2009	1,217,543,467	0	-735,648	1,216,807,819	1,225,399,085
2010	1,259,586,591	6,286,072	-1,158,026	1,264,714,637	1,256,450,873
2011	1,256,773,343	10,647,402	-1,109,083	1,266,311,662	1,265,208,873
2012	1,250,182,338	11,553,261	-946,148	1,260,789,451	1,275,140,355
2013	1,237,895,470	13,069,574	-964,965	1,250,000,080	1,237,576,507
2014	414,428,671	3,640,835	0	418,069,506	1,238,461,756
2015	0	0	0	0	1,245,167,213
Total to 2013	14,794,484,281	41,556,309	-5,900,419	14,830,140,171	14,820,115,026
					23,307,352,587

tistics
0.973136554
0.946994753
0.944266541
2525998.944
144

df	*SS*	*MS*	*F*	*Significance F*
7	1.55036E+16	2.21481E+15	347.1119572	1.9172E-83
136	8.67771E+14	6.38067E+12		
143	1.63714E+16			

Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
-211475540.3	31669469	-6.677584028	5.68104E-10	-274103840	-148847240.6	-274103840	-148847241
23655.34661	1563.834565	15.12650195	6.22069E-31	20562.76871	26747.9245	20562.76871	26747.9245
192326.5874	7655.588226	25.1223788	6.10206E-53	177187.1964	207465.9784	177187.1964	207465.9784
321215.426	131593.1334	2.440974067	0.015933479	60982.00691	581448.845	60982.00691	581448.845
2930932.027	270901.276	10.81918871	4.57352E-20	2395208.289	3466655.765	2395208.289	3466655.765
-5.310486186	0.731738422	-7.257355942	2.73298E-11	-6.757543388	-3.863428983	-6.757543388	-3.86342898
-5190218.41	577566.5042	-8.98635633	1.89855E-15	-6332391.275	-4048045.546	-6332391.275	-4048045.55
1320.705151	344.4990482	3.833697531	0.00019226	639.4373453	2001.972956	639.4373453	2001.972956

	Purchases	Modeled Purchases	Difference	% Difference	Loss Factor	Total Billed	Residential	GS<50	GS>50	Large User	Sentinels	Streetlights	USL
Weather Normal Projection													
1996	0	918,650,549	918,650,549										
1997	0	929,128,148	929,128,148										
1998	0	989,909,522	989,909,522										
1999	0	1,036,760,387	1,036,760,387										
2000	0	1,060,388,686	1,060,388,686										
2001	0	1,068,771,300	1,068,771,300										
2002	1,162,710,674	1,162,665,476	(45,198)	0.0%		0	0	0	0	0	0	0	0
2003	1,152,043,160	1,167,650,716	15,607,556	1.4%	1.0394	1,108,347,420	418,838,012	126,366,945	553,710,685	0	298,685	6,713,622	2,419,471
2004	1,205,241,074	1,182,645,856	(22,595,217)	-1.9%	1.0615	1,135,405,804	404,285,804	122,937,633	598,431,001	0	299,222	7,027,058	2,425,087
2005	1,272,191,339	1,271,722,798	(468,541)	0.0%	1.0524	1,208,894,249	463,562,202	125,194,926	609,950,002	0	336,743	7,458,446	2,391,930
2006	1,248,057,840	1,249,433,262	1,375,422	0.1%	1.0539	1,184,184,647	450,017,939	122,020,708	601,216,533	0	317,191	8,236,754	2,375,520
2007	1,283,916,366	1,270,377,856	(13,538,510)	-1.1%	1.0520	1,220,452,820	462,721,168	125,994,115	622,092,059	0	295,243	7,023,291	2,326,944
2008	1,247,356,069	1,255,843,368	8,487,299	0.7%	1.0492	1,188,897,732	450,470,690	122,663,804	605,669,659	0	286,832	7,504,236	2,302,512
2009	1,216,807,819	1,225,399,085	8,591,266	0.7%	1.0474	1,161,778,118	438,952,918	119,930,976	592,972,281	0	294,273	7,271,510	2,356,161
2010	1,264,714,637	1,256,450,873	(8,263,764)	-0.7%	1.0595	1,193,712,076	451,343,387	121,294,614	611,065,862	0	293,544	7,368,898	2,345,772
2011	1,266,311,662	1,265,208,873	(1,102,789)	-0.1%	1.0270	1,232,998,827	418,849,931	129,680,926	675,128,624	0	246,192	7,294,838	1,798,316
2012	1,260,789,451	1,275,140,355	14,350,904	1.1%	1.0385	1,214,015,314	414,592,237	125,465,897	664,095,955	0	267,435	7,329,519	2,264,271
2013	1,250,000,080	1,237,576,507	(12,423,573)	-1.0%	1.0397	1,202,305,265	412,298,278	124,179,905	655,968,805	0	265,619	7,344,781	2,247,877
2014	418,069,506	1,238,461,756				1,188,072,528							
2015	0	1,245,167,213				1,194,505,161							
							4,785,932,566	1,365,730,448	6,790,301,466	0	3,200,978	80,572,954	25,253,860
							37%	10%	52%	0%	0%	1%	0%
Before Supply Facility Loss Factor of 1.0045				5 year average	1.0424								

Average

	Purchases	Total Billed	Residential	GS<50	GS>50	Sentinels	Streetlights	USL
2005 to 2006	-1.90%	-2.04%	-2.92%	-2.54%	-1.43%	-5.81%	10.44%	-0.69%
2006 to 2007	2.87%	3.06%	2.82%	3.26%	3.47%	-6.92%	-14.73%	-2.04%
2007 to 2008	-2.85%	-2.59%	-2.65%	-2.64%	-2.64%	-2.85%	6.85%	-1.05%
2008 to 2009	-2.45%	-2.28%	-2.56%	-2.23%	-2.10%	2.59%	-3.10%	2.33%
2009 to 2010	3.94%	2.75%	2.82%	1.14%	3.05%	-0.25%	1.34%	-0.44%
2010 to 2011	0.13%	3.29%	-7.20%	6.91%	10.48%	-16.13%	-1.01%	-23.34%
2011 to 2012	-0.44%	-1.54%	-1.02%	-3.25%	-1.63%	8.63%	0.48%	25.91%
2012 to 2013	-0.86%	-0.96%	-0.55%	-1.02%	-1.22%	-0.68%	0.21%	-0.72%

Usage Per Customer

	Residential	GS<50	GS>50	Large User	Sentinels	Streetlights	USL
2003	9,853	31,735	640,869	0	513	591	5,733
2004	9,433	30,483	730,685	0	497	606	5,747
2005	10,763	28,216	760,536	0	645	635	5,668
2006	10,292	27,495	690,260	0	534	698	5,629
2007	10,439	29,038	729,299	0	519	589	5,289
2008	10,020	28,794	715,076	0	508	626	5,175
2009	9,592	28,175	695,793	0	520	599	5,190
2010	9,846	27,840	718,056	0	704	597	5,045
2011	9,106	30,111	786,394	0	667	582	4,241
2012	9,038	29,453	776,553	0	779	586	5,904
2013	8,910	28,776	760,337	0	787	578	5,332
2014	8,821	28,495	773,446	0	822	577	5,293
2015	8,732	28,218	786,781	0	857	576	5,255

	Residential	GS<50	GS>50	Large User	Sentinels	Streetlights	USL
1999							
2000							
2001							
2002							
2003							
2004	0.9573	0.9606	1.1401	0.0000	0.9685	1.0259	1.0023
2005	1.1411	0.9256	1.0409	0.0000	1.2979	1.0466	0.9863
2006	0.9562	0.9744	0.9076	0.0000	0.8278	1.0992	0.9931
2007	1.0143	1.0561	1.0566	0.0000	0.9717	0.8437	0.9395
2008	0.9599	0.9916	0.9805	0.0000	0.9797	1.0638	0.9785
2009	0.9573	0.9785	0.9730	0.0000	1.0237	0.9570	1.0029
2010	1.0265	0.9881	1.0320	0.0000	1.3528	0.9971	0.9720
2011	0.9248	1.0816	1.0952	0.0000	0.9476	0.9737	0.8406

2012		0.9925	0.9781	0.9875	0.0000	1.1681	1.0074	1.3921	
2013		0.9858	0.9770	0.9791	0.0000	1.0102	0.9867	0.9031	
Used		0.9900	0.9903	1.0172	0.0000	1.0437	0.9978	0.9928	
Geomean		0.9900	0.9903	1.0172	0.0000	1.0437	0.9978	0.9928	
Non Weather Corrected Forecast									Total
2014	1,212,698,537	411,649,947	123,963,294	667,180,301	0	262,521	7,411,072	2,231,402	1,212,698,537
2015	1,223,285,582	411,002,636	123,747,060	678,583,419	0	259,459	7,477,962	2,215,047	1,223,285,582
Weather Corrected Forecast									Total
2014	1,188,072,528	402,883,785	121,323,472	653,960,276	0	262,521	7,411,072	2,231,402	1,188,072,528
2015	1,194,505,161	400,859,224	120,693,023	663,000,445	0	259,459	7,477,962	2,215,047	1,194,505,161
		Weather Normalization Percentage from 2006 Hydro One Study							
% Weather Sensitive		93.50%	93.50%	87.00%	0.00%	0.00%	0.00%	0.00%	Total
2014	(24,626,008)	384,892,701	115,905,680	580,446,862	0	0	0	0	1,081,245,242
2015	(28,780,422)	384,287,465	115,703,501	590,367,574	0	0	0	0	1,090,358,540
Allocation of Weather Sensitive Amount									Total
2014		(8,766,162)	(2,639,821)	(13,220,025)	0	0	0	0	(24,626,008)
2015		(10,143,411)	(3,054,037)	(15,582,973)	0	0	0	0	(28,780,422)
CDM Manual Adjustment to the Load Forecast from 2013 and 2014 Programs on a Net Level									Total
2014	(3,619,024)	(704,965)	(813,230)	(2,100,829)	0	0	0	0	(3,619,024)
2015	(8,688,049)	(1,692,381)	(1,952,290)	(5,043,378)	0	0	0	0	(8,688,049)
Weather Corrected Forecast after 2013 and 2014 CDM Adjustments									Adj Weather Total
2014	1,184,453,504	402,178,821	120,510,242	651,859,447	0	262,521	7,411,072	2,231,402	1,184,453,504
2015	1,185,817,112	399,166,843	118,740,733	657,957,068	0	259,459	7,477,962	2,215,047	1,185,817,112
	-2.03%	-2.13%	-2.13%	-1.98%	#DIV/0!	0.00%	0.00%	0.00%	-2.03%
	-2.35%	-2.47%	-2.47%	-2.30%	#DIV/0!	0.00%	0.00%	0.00%	-2.35%
% of Total for CDM									
2014		19.48%	22.47%	58.05%					
2015		19.48%	22.47%	58.05%					

Average Number of Customers or Connections

	Residential	GS<50	GS>50	Large User	Sentinels	Streetlights	USL	Total
1999								
2000								
2001								
2002	40,624	4,171	796	0	582	11,157	419	57,749
2003	42,507	3,982	864	0	582	11,358	422	59,715
2004	42,859	4,033	819	0	602	11,588	422	60,323
2005	43,068	4,437	802	0	522	11,752	422	61,003
2006	43,724	4,438	871	0	594	11,807	422	61,856
2007	44,325	4,339	853	0	569	11,933	440	62,459
2008	44,955	4,260	847	0	564	11,986	445	63,057
2009	45,761	4,257	852	0	566	12,136	454	64,026
2010	45,840	4,357	851	0	417	12,334	465	64,264
2011	45,996	4,307	859	0	369	12,540	424	64,494
2012	45,871	4,260	855	0	343	12,507	384	64,220
2013	46,274	4,315	863	0	337	12,702	422	64,913
2014	46,669	4,350	863	0	320	12,845	422	65,467
2015	47,067	4,385	862	0	303	12,989	422	66,028

Growth Rate in Customer Numbers

1999							
2000							
2001							
2002							
2003							
2004	1.0083	1.0128	0.9479	0.0000	1.0344	1.0203	1.0000
2005	1.0049	1.1002	0.9792	0.0000	0.8671	1.0142	1.0000
2006	1.0152	1.0002	1.0860	0.0000	1.1379	1.0047	1.0000
2007	1.0137	0.9777	0.9793	0.0000	0.9579	1.0107	1.0427
2008	1.0142	0.9818	0.9930	0.0000	0.9917	1.0044	1.0113
2009	1.0179	0.9992	1.0062	0.0000	1.0022	1.0126	1.0203
2010	1.0017	1.0235	0.9986	0.0000	0.7374	1.0163	1.0242
2011	1.0034	0.9885	1.0088	0.0000	0.8851	1.0166	0.9119
2012	0.9973	0.9891	0.9961	0.0000	0.9299	0.9974	0.9045
2013	1.0088	1.0130	1.0088	0.0000	0.9832	1.0156	1.0992
Used	1.0085	1.0081	0.9999	0.0000	0.9470	1.0112	0.9999
Geomean	1.0085	1.0081	0.9999	0.0000	0.9470	1.0112	0.9999

Average Load by Rate Class

	GS>50	Large User	Sentinels	Streetlights	Total
1999					
2000					
2001					
2002	1,529,263	0	956	17,456	1,547,675
2003	1,573,551	0	968	17,588	1,592,107
2004	1,673,046	0	933	19,480	1,693,459
2005	1,719,941	0	892	19,789	1,740,622
2006	1,777,691	0	831	19,932	1,798,454
2007	1,884,479	0	825	20,188	1,905,492
2008	1,735,816	0	733	20,371	1,756,920
2009	1,753,191	0	695	20,319	1,774,205
2010	1,769,836	0	653	19,656	1,790,145
2011	1,793,543	0	679	20,391	1,814,614
2012	1,761,221	0	721	21,037	1,782,980
2013	1,721,554	0	716	20,809	1,743,079
2014	1,723,755	0	713	20,995	1,745,463
2015	1,739,879	0	705	21,184	1,761,769

kW/kWh

1999				
2000				
2001				
2002				
2003	0.2842%	#DIV/0!	0.3241%	0.2620%
2004	0.2796%	#DIV/0!	0.3118%	0.2772%
2005	0.2820%	#DIV/0!	0.2649%	0.2653%
2006	0.2957%	#DIV/0!	0.2620%	0.2420%
2007	0.3029%	#DIV/0!	0.2794%	0.2874%
2008	0.2866%	#DIV/0!	0.2556%	0.2715%
2009	0.2957%	#DIV/0!	0.2362%	0.2794%
2010	0.2896%	#DIV/0!	0.2225%	0.2667%
2011	0.2657%	#DIV/0!	0.2760%	0.2795%
2012	0.2652%	#DIV/0!	0.2695%	0.2870%
2013	0.2624%	#DIV/0!	0.2696%	0.2833%
11 Year Aver	0.2827%	#DIV/0!	0.2701%	0.2729%
3 Year Avera	0.2644%	#DIV/0!	0.2717%	0.2833%

Long-Term Load Transfer Data

NPEI Geographic (A/P)

							Used 2012 as estimate for missing info
		2008	**2009**	**2010**	**2011**	**2012**	**2013**
Physical Distributor	**Customer Class**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**
CNP	Residential	132,652	142,273	145,366	124,739	113,652	113,652
NOTL	Residential	110141	132870	129,366	102,698	109,292	109,292
Hydro One	Residential	1,006,943	1,039,014	1,096,349	1,225,535	1,246,238	1,217,154
	GS<50	167,608	176,995	169,698	187,767	187,406	162,920
	GS>50	0	0	159,816	159,600	161,520	162,240
Welland Horizon	Residential	122,030	129,571	137,514	119,214	139,802	139,802
Horizon	Residential	201,016	116,619	96,514	75,198	74,601	74,601
	GS<50	7434	7,830	7,667	10,596	12,211	12,211
Grimsby	Residential	37,880	34,050	33,735	33,000	27,693	28,352
	GS<50	4,069	8,280	29,920	12,510	6,930	24,373
Total		1,785,704	1,787,502	2,005,945	2,050,856	2,079,345	2,044,597

NPEI Physical (A/R)

		2008	**2009**	**2010**	**2011**	**2012**	**2013**
Physical Distributor	**Customer Class**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**
Hydro One	Residential	1,764,940	1,749,584	1,607,727	1,826,404	1,770,935	1,823,409
	GS<50	458,287	516,008	670,650	335,668	249,984	217,892
	GS>50	174,460	70,720	710,920	831,960	838,860	807,920
Horizon	Residential	40,303	44,356	39,541	36,332	34,441	34,441
Grimsby	Residential	317,659	117,478	115,641	106,860	104,598	97,214
	GS<50	16,604	25,004	19,492	22,715	26,675	28,686
		2,772,253	2,523,150	3,163,971	3,159,939	3,025,493	3,009,562
Summary Net Load Transfer		**(986,549.00)**	**(735,648.00)**	**(1,158,026.16)**	**(1,109,082.61)**	**(946,148.32)**	**(964,964.86)**

Month	**Kwh per month**
Jan-08	(82,212)
Feb-08	(82,212)
Mar-08	(82,212)
Apr-08	(82,212)
May-08	(82,212)
Jun-08	(82,212)
Jul-08	(82,212)
Aug-08	(82,212)
Sep-08	(82,212)

Oct-08	(82,212)
Nov-08	(82,212)
Dec-08	(82,212)
Jan-09	(61,304)
Feb-09	(61,304)
Mar-09	(61,304)
Apr-09	(61,304)
May-09	(61,304)
Jun-09	(61,304)
Jul-09	(61,304)
Aug-09	(61,304)
Sep-09	(61,304)
Oct-09	(61,304)
Nov-09	(61,304)
Dec-09	(61,304)
Jan-10	(96,502.18)
Feb-10	(96,502.18)
Mar-10	(96,502.18)
Apr-10	(96,502.18)
May-10	(96,502.18)
Jun-10	(96,502.18)
Jul-10	(96,502.18)
Aug-10	(96,502.18)
Sep-10	(96,502.18)
Oct-10	(96,502.18)
Nov-10	(96,502.18)
Dec-10	(96,502.18)
Jan-11	(92,423.55)
Feb-11	(92,423.55)
Mar-11	(92,423.55)
Apr-11	(92,423.55)
May-11	(92,423.55)
Jun-11	(92,423.55)
Jul-11	(92,423.55)
Aug-11	(92,423.55)
Sep-11	(92,423.55)
Oct-11	(92,423.55)
Nov-11	(92,423.55)
Dec-11	(92,423.55)
Jan-12	(78,845.69)
Feb-12	(78,845.69)
Mar-12	(78,845.69)
Apr-12	(78,845.69)
May-12	(78,845.69)

Jun-12	(78,845.69)
Jul-12	(78,845.69)
Aug-12	(78,845.69)
Sep-12	(78,845.69)
Oct-12	(78,845.69)
Nov-12	(78,845.69)
Dec-12	(78,845.69)
Jan-13	(80,413.74)
Feb-13	(80,413.74)
Mar-13	(80,413.74)
Apr-13	(80,413.74)
May-13	(80,413.74)
Jun-13	(80,413.74)
Jul-13	(80,413.74)
Aug-13	(80,413.74)
Sep-13	(80,413.74)
Oct-13	(80,413.74)
Nov-13	(80,413.74)
Dec-13	(80,413.74)

OPA Conservation & Demand Management Programs

Annual Results at the End-User Level

For: Niagara Peninsula Energy Inc.

Net Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	2006 Programs	Final	3.0901	0.2039	0.2039	0.2039	0.2039	0.2039	0.1898	0.1898	0.1484	0.1484
2	2007 Programs	Final	0.0000	4.7648	0.5359	0.3880	0.3880	0.3861	0.3712	0.3712	0.3712	0.3296
3	2008 Programs	Final	0.0000	0.0000	6.6749	1.0099	1.0099	1.0099	1.0040	1.0040	0.9912	0.9869
4	2009 Programs	Final	0.0000	0.0000	0.0000	5.7505	0.8720	0.8720	0.8701	0.8556	0.8256	0.8220
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	4.8693	1.0760	1.0755	1.0728	1.0545	1.0076
Total			**3.0901**	**4.9687**	**7.4147**	**7.3524**	**7.3432**	**3.5479**	**3.5106**	**3.4934**	**3.3910**	**3.2946**

Net Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	2006 Programs	Final	4,211	4,211	4,211	4,211	731	731	669	669	629	629
2	2007 Programs	Final	0	3,589	2,152	1,974	1,974	1,973	1,908	1,908	1,908	653
3	2008 Programs	Final	0	0	3,033	2,473	2,473	2,473	2,297	2,297	2,113	1,976
4	2009 Programs	Final	0	0	0	4,448	3,613	3,613	3,611	3,522	3,287	3,045
5	2010 Programs	Final	0	0	0	0	5,435	4,043	4,037	4,035	3,930	3,511
Total			**4,211**	**7,801**	**9,397**	**13,106**	**14,226**	**12,834**	**12,522**	**12,430**	**11,867**	**9,814**

Gross Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	2006 Programs	Final	3.1277	0.2416	0.2416	0.2416	0.2416	0.2416	0.2258	0.2258	0.1799	0.1799
2	2007 Programs	Final	0.0000	11.9992	2.8446	1.6122	1.6122	1.6077	1.5299	1.5299	1.5299	1.4635
3	2008 Programs	Final	0.0000	0.0000	7.0825	1.3853	1.3853	1.3853	1.3697	1.3697	1.3418	1.3303
4	2009 Programs	Final	0.0000	0.0000	0.0000	6.2763	1.3930	1.3930	1.3892	1.3590	1.3039	1.2962
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	5.5019	1.7094	1.7094	1.7019	1.6628	1.5754
Total			**3.1277**	**12.2408**	**10.1687**	**9.5153**	**10.1340**	**6.3370**	**6.2241**	**6.1863**	**6.0183**	**5.8453**

Gross Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	2006 Programs	Final	4,703	4,703	4,703	4,703	837	837	767	767	722	722
2	2007 Programs	Final	0	17,078	5,211	3,720	3,720	3,719	3,537	3,537	3,537	1,613
3	2008 Programs	Final	0	0	5,842	5,113	5,113	5,113	4,655	4,655	4,244	3,879
4	2009 Programs	Final	0.0000	0.0000	0.0000	6,821.2054	5,875.9691	5,875.9691	5,872.0270	5,698.5793	5,256.3914	4,903.1878
5	2010 Programs	Final	0	0	0	0	8,091	6,724	6,723	6,716	6,511	5,638
Total			**4,703**	**21,781**	**15,757**	**20,357**	**23,636**	**22,268**	**21,554**	**21,373**	**20,271**	**16,756**

Methodology for Implementing CDM Explanatory Variable,
as per Board Staff Interrogatory #22, London Hydro COS Application EB-2012-0146/EB-2012-0380

Year	Reported Savings (kWh)	Incremental Savings (Reported Savings less Prior Year)	First Year (Half of Incremental Savings)	Monthly Increment (Year/78)
2006	4,211,271	4,211,271	2,105,636	26,995
2007	7,800,592	3,589,321	1,794,660	23,008
2008	9,396,789	1,596,197	798,099	10,232
2009	13,106,362	3,709,573	1,854,786	23,779
2010	14,225,868	1,119,506	559,753	7,176
2011	17,860,867	3,634,999	1,817,499	23,301
2012	23,164,672	5,303,805	2,651,903	33,999
2013	30,183,942	7,019,270	3,509,635	44,995
2014	36,443,378	6,259,435	3,129,718	40,125
2015	36,522,714	79,337	39,668	509

Jan	1
Feb	2
Mar	3
Apr	4
May	5
Jun	6
Jul	7
Aug	8
Sep	9
Oct	10
Nov	11
Dec	12
Total	78

Based on 2012 Final Report

4 Year (2011-2014) kWh Target:					
		58,000,000			
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	8.67%	8.67%	8.45%	7.93%	33.71%
2012 CDM Programs		9.68%	9.68%	9.48%	28.85%
2013 CDM Programs			12.48%	12.48%	24.96%
2014 CDM Programs				12.48%	12.48%
Total in Year	**8.67%**	**18.35%**	**30.61%**	**42.37%**	**100.00%**
		kWh			
2011 CDM Programs	5,026,978.00	5,026,978.00	4,900,000.00	4,600,000.00	19,553,956.00
2012 CDM Programs		5,615,949.00	5,615,949.00	5,500,000.00	16,731,898.00
2013 CDM Programs			7,238,048.67	7,238,048.67	14,476,097.33
2014 CDM Programs				7,238,048.67	7,238,048.67
Total in Year	**5,026,978.00**	**10,642,927.00**	**17,753,997.67**	**24,576,097.33**	**58,000,000.00**

NPEI CDM Programs Net Energy Savings (MWh) As reported by the OPA (Annualized Basis)

		Effect in Year									
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Year Initiated	**2006**	4,211	4,211	4,211	4,211	731	731	669	669	629	629
	2007		3,589	2,152	1,974	1,974	1,973	1,908	1,908	1,908	653
	2008			3,033	2,473	2,473	2,473	2,297	2,297	2,113	1,976
	2009				4,448	3,613	3,613	3,611	3,522	3,287	3,045
	2010					5,435	4,043	4,037	4,035	3,930	3,511
	2011						5,027	5,027	4,900	4,600	4,318
	2012							5,616	5,616	5,500	5,163
	2013								7,238	7,238	7,089
	2014									7,238	7,238
	2015										2,900
	Total	4,211	7,801	9,397	13,106	14,226	17,861	23,165	30,184	36,443	36,523

Manual Adjustments to Load Forecast:

2014 Bridge Year:

50% of 2014 Initiatives	(3,619)
	(3,619)

2015 Test Year:

100% of 2014 Initiatives	(7,238)
50% of 2015 Initiatives	(1,450)
	(8,688)

Jan-06	13,498	Jan-08	555,158	Jan-10	927,755	Jan-12	1,276,419	Jan-14	2,148,417
Feb-06	40,493	Feb-08	565,390	Feb-10	934,931	Feb-12	1,310,418	Feb-14	2,188,542
Mar-06	67,488	Mar-08	575,622	Mar-10	942,107	Mar-12	1,344,417	Mar-14	2,228,666
Apr-06	94,484	Apr-08	585,854	Apr-10	949,284	Apr-12	1,378,416	Apr-14	2,268,791
May-06	121,479	May-08	596,086	May-10	956,460	May-12	1,412,414	May-14	2,308,916
Jun-06	148,474	Jun-08	606,318	Jun-10	963,636	Jun-12	1,446,413	Jun-14	2,349,040
Jul-06	175,470	Jul-08	616,550	Jul-10	970,813	Jul-12	1,480,412	Jul-14	2,389,165
Aug-06	202,465	Aug-08	626,782	Aug-10	977,989	Aug-12	1,514,411	Aug-14	2,429,289
Sep-06	229,460	Sep-08	637,014	Sep-10	985,165	Sep-12	1,548,409	Sep-14	2,469,414
Oct-06	256,456	Oct-08	647,246	Oct-10	992,342	Oct-12	1,582,408	Oct-14	2,509,538
Nov-06	283,451	Nov-08	657,478	Nov-10	999,518	Nov-12	1,616,407	Nov-14	2,549,663
Dec-06	296,949	Dec-08	662,594	Dec-10	1,003,106	Dec-12	1,633,406	Dec-14	2,569,725
Jan-07	308,453	Jan-09	674,484	Jan-11	1,014,757	Jan-13	1,655,904	Jan-15	2,569,980
Feb-07	331,461	Feb-09	698,263	Feb-11	1,038,058	Feb-13	1,700,899	Feb-15	2,570,488
Mar-07	354,470	Mar-09	722,042	Mar-11	1,061,359	Mar-13	1,745,895	Mar-15	2,570,997
Apr-07	377,478	Apr-09	745,822	Apr-11	1,084,661	Apr-13	1,790,890	Apr-15	2,571,505
May-07	400,487	May-09	769,601	May-11	1,107,962	May-13	1,835,885	May-15	2,572,014
Jun-07	423,495	Jun-09	793,380	Jun-11	1,131,263	Jun-13	1,880,881	Jun-15	2,572,522
Jul-07	446,504	Jul-09	817,160	Jul-11	1,154,564	Jul-13	1,925,876	Jul-15	2,573,031
Aug-07	469,512	Aug-09	840,939	Aug-11	1,177,866	Aug-13	1,970,871	Aug-15	2,573,540
Sep-07	492,521	Sep-09	864,718	Sep-11	1,201,167	Sep-13	2,015,867	Sep-15	2,574,048
Oct-07	515,529	Oct-09	888,498	Oct-11	1,224,468	Oct-13	2,060,862	Oct-15	2,574,557
Nov-07	538,538	Nov-09	912,277	Nov-11	1,247,769	Nov-13	2,105,857	Nov-15	2,575,065
Dec-07	550,042	Dec-09	924,167	Dec-11	1,259,420	Dec-13	2,128,355	Dec-15	2,575,320

Initiative	Unit	Incremental Activity				Net Incremental Peak Demand Savings (kW)				Net Incremental Energy Savings (kWh)				2014 Net Annual Peak	2011-2014 Cumulative Energy				
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014				
Consumer Program																Consumer	<50kW	>50kW	
Appliance	Appliances	512	339	158		30	20	9		214,685	135,814	63,786	0	59	1,393,046	1,393,046			Residential
Appliance	Appliances	44	56	32		4	8	5		4,714	14,737	8,368		14	76,976	76,976			Residential
HVAC Ince	Equipment	880	712	622		282	151	134		504,642	253,365	226,291		568	3,231,245	2,908,121	323,125		Residential (10% <50kW)
Conservati	Coupons	7,729	307	1,040		15	2	2		272,325	13,904	31,226		19	1,193,463	1,193,463			Residential
Bi-Annual	Coupons	9,469	10,550	10,472		17	15	16		292,245	266,332	302,178		47	2,572,330	2,572,330			Residential
Retailer Co	Items	0	0	0		0	0	0		0	0	0		0	0	-			
Residentia	Devices	47	0	283		26	0	164		0	0	1,313		0	1,313	1,313			
Residentia	Devices	0	0	275		0				0	0			0	0				
Residentia	Homes	0	0			0				0	0			0	0				
Consumer Program Total						**374**	**196**	**330**	**0**	**1,288,611**	**684,152**	**633,162**	**0**	**707**	**8,468,373**	**8,145,249**	**323,125**	**0**	
Business Program																			
Retrofit	Projects	36	80	102		168	767	426		927,120	3,486,336	1,879,279		1,336	17,797,457		1,705,341	16,092,116	91% >50kW 9%<50kW
Direct Inst	Projects	347	217	140		333	177	162		903,623	712,848	700,564		533	6,675,457		6,675,457		<50kW
Building Co	Buildings	0	0	0		0	0	0		0	0	0		0	0				
New Const	Buildings	0	0	0		0	0	0		0	0	0		0	0				
Energy Au	Audits	3	8	1		0	41	5		0	201,410	25,175		47	654,583			654,583	
Small Com	Devices	4	0	1		3	0	1		0	0	5		0	5			5	
Small Com	Devices	0	0	1		0	0	0		0	0	0		0	0				
Demand R	Facilities	3	3	2		106	106	106		4,146	1,548	1,548		0	7,242			7,242	>50kW
Business Program Total						**610**	**1,091**	**700**	**0**	**1,834,889**	**4,402,142**	**2,606,571**	**0**	**1,916**	**25,134,744**	**0**	**8,380,798**	**16,753,946**	
Industrial Program Total																			
Process &	Projects	0	0	0		0	0	0		0	0								
Monitoring	Projects	0	0	0		0	0	0		0	0								
Energy Ma	Projects	0	0	0		0	0	0		0	0								
Retrofit	Projects	1	0	0		2	0	0		13,815	0	0	0	2	55,262			55,262	>50kW
Demand R	Facilities	1	1	5		63	65	506		3,710	1,578	12,203	0	0	17,491			17,491	>50kW
Industrial Program Total						**65**	**65**	**506**	**0**	**17,525**	**1,578**	**12,203**	**0**	**2**	**72,753**	**0**	**0**	**72,753**	
Home Assistance Program																			
Home Assi	Homes	10	44	178		0	5	10		9,137	54,743	123,348	0	15	447,473	447,473			
Industrial Program Total						**0**	**5**	**10**	**0**	**9,137**	**54,743**	**123,348**	**0**	**15**	**447,473**	**447,473**	**0**	**0**	
Pre-2011 Program																			
ERIP	Projects	23	0			263	0			1,480,972	0	0	0	263	5,923,888		567,623	5,356,265	91% >50kW 9%<50kW
HPNC	Projects	3	2			77	136			395,844	643,518	0	0	213	3,513,933			3,513,933	>50kW
Toronto Co	Projects	0	0			0	0			0	0								
Multifamil	Projects	0	0			0	0			0	0								
LDC Custo	Projects	0	0			0	0			0	0								
Total Pre-2011 Programs						**340**	**136**	**0**	**0**	**1,876,816**	**643,518**	**0**	**0**	**476**	**9,437,821**	**0**	**567,623**	**8,870,198**	
Other																			
Program E	Projects	0	0			0	0			0	0	0	0	0	0				
Time-of-us	Homes	0	0			0	0			0	0	0	0	0	0				
Total Other						0	0	0	0	0	0	0	0	0	0				
Adjustments to Previous Year's Verified Results						**0**	**-7**				**-170,184**			**-16**	**-716,260**	(246,785)	356,126	(825,601)	
Energy Efficiency Total						**1,191**	**1,322**	**769**	**0**	**5,019,122**	**5,783,007**	**3,360,215**	**0**	**3,116**	**43,535,113**	**8,591,409**	**9,271,545**	**25,672,159**	
Demand Response Total (Scenario 1)						**198**	**171**	**777**	**0**	**7,856**	**3,126**	**15,069**	**0**	**0**	**26,051**	**1,313**	**0**	**24,738**	
OPA-Contracted LDC Portfolio Total (incl. Adjustments)						**1,389**	**1,486**	**1,546**	**0**	**5,026,978**	**5,615,949**	**3,375,284**	**0**	**3,100**	**42,844,904**	**8,345,937**	**9,627,671**	**24,871,296**	
																19.4794%	22.4710%	58.0496%	
												OEB Target		**15,500**	**58,000,000**				
												% of OEB Target Achieved		**20%**	**74%**				

2014 Load Forecast	kWh	kW	2013 %RPP
Residential	402,178,821		92%
GS<50	120,510,242		86%
GS>50	651,859,447	1,723,755	5%
Large User	0	-	0%
Sentinels	262,521	713	81%
Streetlights	7,411,072	20,995	1%
USL	2,231,402		100%
TOTAL	**1,184,453,504**	**1,745,463**	

Electricity - Commodity RPP					
Class per Load Forecast RPP	**2014 Forecasted Metered kWhs**	**2014 Loss Factor**	**2014**		
Residential	370,922,053	1.0479	388,698,148	$0.09250	$35,954,579
GS<50	103,510,458	1.0479	108,471,100	$0.09250	$10,033,577
GS>50	34,697,584	1.0479	36,360,433	$0.09250	$3,363,340
Large User	0	1.0479	0	$0.09250	$0
Sentinels	212,433	1.0479	222,614	$0.09250	$20,592
Streetlights	78,690	1.0479	82,461	$0.09250	$7,628
USL	2,231,402	1.0479	2,338,339	$0.09250	$216,296
TOTAL	**511,652,619**		**536,173,096**		**$49,596,011**

Electricity - Commodity Non-RPP					
Class per Load Forecast	**2014 Forecasted Metered kWhs**	**2014 Loss Factor**	**2014**		
Residential	31,256,768	1.0479	32,754,719	$0.09096	$2,979,369
GS<50	16,999,785	1.0479	17,814,483	$0.09096	$1,620,405
GS>50	617,161,863	1.0479	646,738,772	$0.09096	$58,827,359
Large User	0	1.0479	0	$0.09096	$0
Sentinels	50,088	1.0479	52,488	$0.09096	$4,774
Streetlights	7,332,382	1.0479	7,683,780	$0.09096	$698,917
USL	0	1.0479	0	$0.09096	$0
TOTAL	**672,800,885**		**705,044,243**		**$64,130,824**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2014**		
Residential		kWh	421,452,867	$0.0073	$3,076,606
GS<50		kWh	126,285,583	$0.0066	$833,485
GS>50		kW	1,723,755	$2.7218	$4,691,717
Large User		kW	0	$0.0000	$0
Sentinels		kW	713	$2.0152	$1,438
Streetlights		kW	20,995	$2.0576	$43,199
USL		kWh	2,338,339	$0.0066	$15,433
TOTAL					**$8,661,877**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2014**		
Residential		kWh	421,452,867	$0.0050	$2,107,264
GS<50		kWh	126,285,583	$0.0044	$555,657
GS>50		kW	1,723,755	$1.7467	$3,010,883
Large User		kW	0	$0.0000	$0
Sentinels		kW	713	$1.4595	$1,041
Streetlights		kW	20,995	$1.3420	$28,175
USL		kWh	2,338,339	$0.0044	$10,289
TOTAL					**$5,713,309**

Wholesale Market Service					
Class per Load Forecast			**2014**		
Residential			421,452,867	$0.0044	$1,966,780
GS<50			126,285,583	$0.0044	$589,333
GS>50			683,099,206	$0.0044	$3,187,796
Large User			0	$0.0044	$0

Sentinels			275,102	$0.0044	$1,284
Streetlights			7,766,241	$0.0044	$36,242
USL			2,338,339	$0.0044	$10,289
TOTAL			**1,241,217,338**		**$5,791,724**

Rural Rate Assistance					
Class per Load Forecast				**2014**	
Residential			421,452,867	$0.0013	$547,889
GS<50			126,285,583	$0.0013	$164,171
GS>50			683,099,206	$0.0013	$888,029
Large User			0	$0.0013	$0
Sentinels			275,102	$0.0013	$358
Streetlights			7,766,241	$0.0013	$10,096
USL			2,338,339	$0.0013	$3,040
TOTAL			**1,241,217,338**		**$1,613,583**

Smart Meter Entity Charge					
Class per Load Forecast				**2014**	
Residential			560,023	$0.7900	$442,418
GS<50			52,204	$0.7900	$41,241
TOTAL			**612,227**		**$483,659**

	2014
4705-Power Purchased	$113,726,836
4708-Charges-WMS	$7,405,307
4714-Charges-NW	$8,661,877
4716-Charges-CN	$5,713,309
4751-Smart Meter Entity	$483,659
TOTAL	**$135,990,987**

2015 Load Forecast	kWh	kW	2013 %RPP
Residential	399,166,843		92%
GS<50	118,740,733		86%
GS>50	657,957,068	1,739,879	5%
Large User	0	-	0%
Sentinels	259,459	705	81%
Streetlights	7,477,962	21,184	1%
USL	2,215,047		100%
TOTAL	**1,185,817,112**	**1,761,769**	

Electricity - Commodity RPP					
Class per Load Forecast RPP	**2015 Forecasted Metered kWhs**	**2015 Loss Factor**	**2015**		
Residential	368,144,162	1.0479	385,787,129	$0.09250	$35,685,309
GS<50	101,990,564	1.0479	106,878,368	$0.09250	$9,886,249
GS>50	35,022,152	1.0479	36,700,556	$0.09250	$3,394,801
Large User	0	1.0479	0	$0.09250	$0
Sentinels	209,955	1.0479	220,017	$0.09250	$20,352
Streetlights	79,400	1.0479	83,205	$0.09250	$7,696
USL	2,215,047	1.0479	2,321,201	$0.09250	$214,711
TOTAL	**507,661,281**		**531,990,477**		**$49,209,119**

Electricity - Commodity Non-RPP					
Class per Load Forecast	**2015 Forecasted Metered kWhs**	**2015 Loss Factor**	**2015**		
Residential	31,022,681	1.0479	32,509,414	$0.09096	$2,957,056
GS<50	16,750,169	1.0479	17,552,905	$0.09096	$1,596,612
GS>50	622,934,916	1.0479	652,788,493	$0.09096	$59,377,641
Large User	0	1.0479	0	$0.09096	$0
Sentinels	49,503	1.0479	51,876	$0.09096	$4,719
Streetlights	7,398,562	1.0479	7,753,131	$0.09096	$705,225
USL	0	1.0479	0	$0.09096	$0
TOTAL	**678,155,831**		**710,655,819**		**$64,641,253**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2015**		
Residential		kWh	418,296,544	$0.0073	$3,053,565
GS<50		kWh	124,431,272	$0.0066	$821,246
GS>50		kW	1,739,879	$2.7218	$4,735,604
Large User		kW	0	$0.0000	$0
Sentinels		kW	705	$2.0152	$1,421
Streetlights		kW	21,184	$2.0576	$43,589
USL		kWh	2,321,201	$0.0066	$15,320
TOTAL					**$8,670,744**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2015**		
Residential		kWh	418,296,544	$0.0050	$2,091,483
GS<50		kWh	124,431,272	$0.0044	$547,498
GS>50		kW	1,739,879	$1.7467	$3,039,047
Large User		kW	0	$0.0000	$0
Sentinels		kW	705	$1.4595	$1,029
Streetlights		kW	21,184	$1.3420	$28,429
USL		kWh	2,321,201	$0.0044	$10,213
TOTAL					**$5,717,699**

Wholesale Market Service					
Class per Load Forecast			**2015**		
Residential			418,296,544	$0.0044	$1,952,051
GS<50			124,431,272	$0.0044	$580,679
GS>50			689,489,049	$0.0044	$3,217,616
Large User			0	$0.0044	$0
Sentinels			271,893	$0.0044	$1,269
Streetlights			7,836,336	$0.0044	$36,570
USL			2,321,201	$0.0044	$10,213
TOTAL			**1,242,646,296**		**$5,798,397**

Rural Rate Assistance					
Class per Load Forecast			**2015**		
Residential			418,296,544	$0.0013	$543,786
GS<50			124,431,272	$0.0013	$161,761
GS>50			689,489,049	$0.0013	$896,336
Large User			0	$0.0013	$0
Sentinels			271,893	$0.0013	$353
Streetlights			7,836,336	$0.0013	$10,187
USL			2,321,201	$0.0013	$3,018
TOTAL			**1,242,646,296**		**$1,615,440**

Smart Meter Entity Charge					
Class per Load Forecast			**2015**		
Residential			564,799	$0.7900	$446,191
GS<50			52,625	$0.7900	$41,574
TOTAL			**617,424**		**$487,765**

	2015
4705-Power Purchased	$113,850,372
4708-Charges-WMS	$7,413,837
4714-Charges-NW	$8,670,744
4716-Charges-CN	$5,717,699
4751-Smart Meter Entity	$487,765
TOTAL	**$136,140,418**

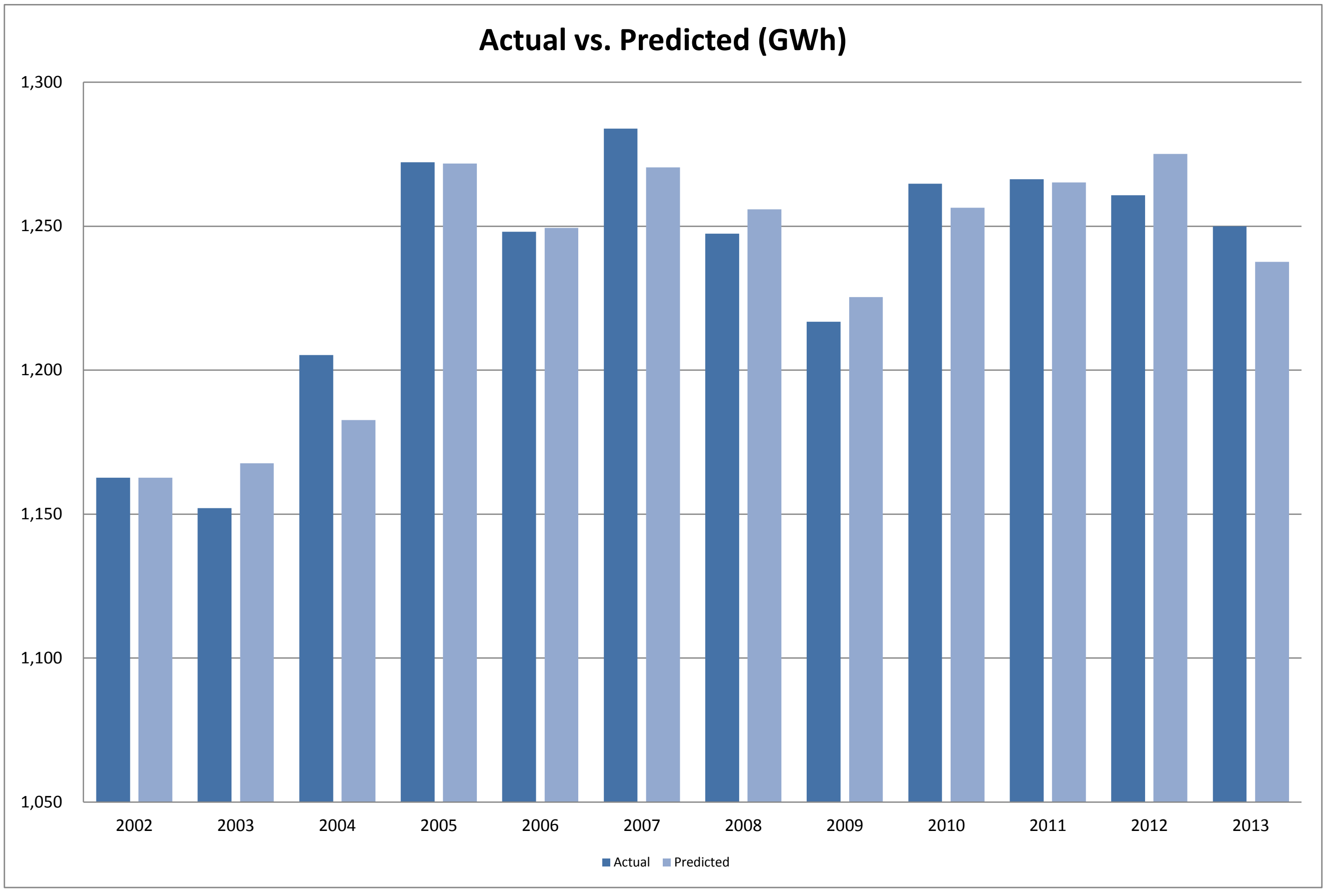
Calculation of Mean Absolute Percentage Error (MAPE)

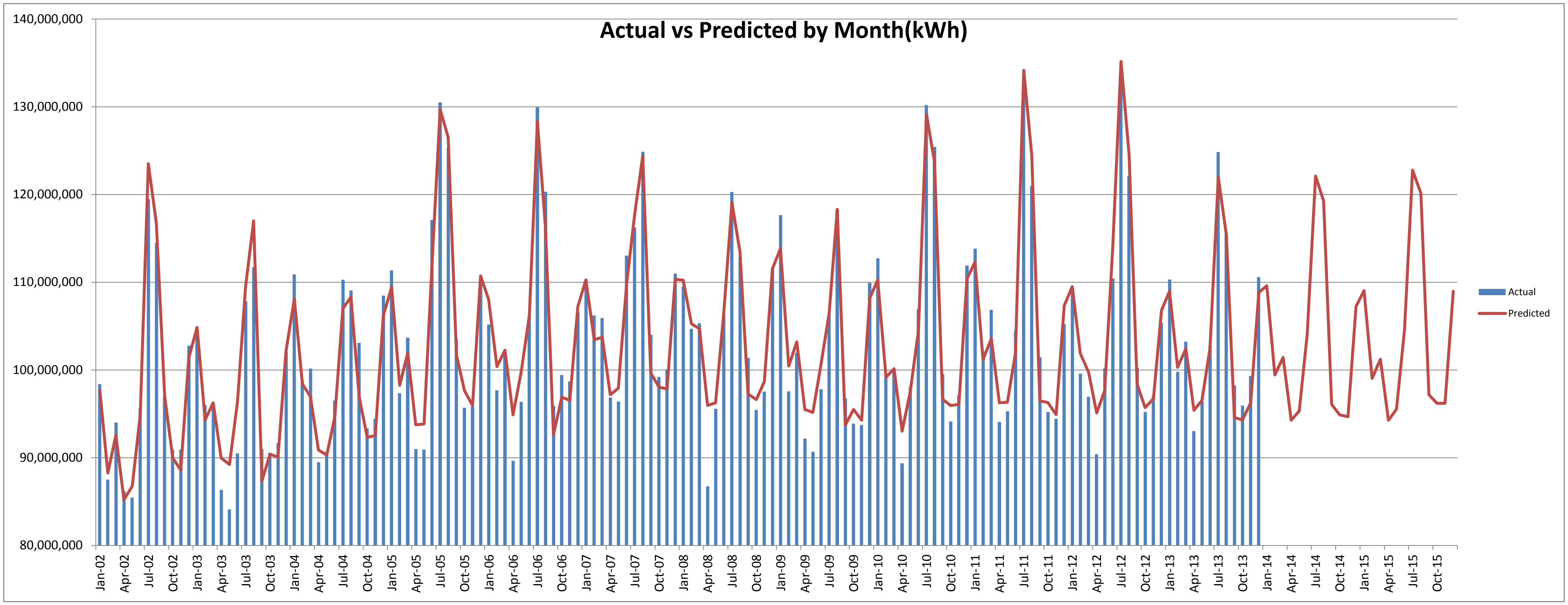
Month	Actual kWh	Predicted kWh	Difference	Absolute Value of Difference	Absolute Value of Difference / Actual
Jan-02	98,398,774	97,692,694	706,080	706,080	0.007175699
Feb-02	87,515,454	88,253,106	-737,652	737,652	0.008428818
Mar-02	94,028,461	92,609,630	1,418,831	1,418,831	0.015089383
Apr-02	86,184,466	85,214,616	969,849	969,849	0.011253179
May-02	85,447,299	86,740,751	-1,293,452	1,293,452	0.015137424
Jun-02	95,651,673	94,950,462	701,210	701,210	0.007330875
Jul-02	119,450,096	123,515,844	-4,065,747	4,065,747	0.034037206
Aug-02	114,483,163	116,730,864	-2,247,701	2,247,701	0.019633462
Sep-02	96,936,653	97,037,179	-100,526	100,526	0.001037027
Oct-02	90,917,731	89,981,481	936,250	936,250	0.01029777
Nov-02	90,920,618	88,581,118	2,339,500	2,339,500	0.025731235
Dec-02	102,776,286	101,357,731	1,418,555	1,418,555	0.013802355
Jan-03	104,493,535	104,864,772	-371,237	371,237	0.003552732
Feb-03	96,011,347	94,315,757	1,695,590	1,695,590	0.017660309
Mar-03	95,684,640	96,256,792	-572,152	572,152	0.005979555
Apr-03	86,343,957	89,975,379	-3,631,421	3,631,421	0.04205762
May-03	84,100,206	89,236,537	-5,136,331	5,136,331	0.061073944
Jun-03	90,485,413	96,441,719	-5,956,306	5,956,306	0.06582615
Jul-03	107,838,219	109,500,535	-1,662,316	1,662,316	0.015414906
Aug-03	111,720,633	117,008,526	-5,287,893	5,287,893	0.04733139
Sep-03	90,994,824	87,376,123	3,618,701	3,618,701	0.039768208
Oct-03	90,574,201	90,389,955	184,247	184,247	0.002034207
Nov-03	91,660,392	90,072,437	1,587,956	1,587,956	0.017324338
Dec-03	102,135,791	102,212,184	-76,392	76,392	0.000747948
Jan-04	110,906,403	108,112,770	2,793,634	2,793,634	0.025189112
Feb-04	98,773,310	98,419,855	353,454	353,454	0.003578439
Mar-04	100,169,246	96,968,541	3,200,706	3,200,706	0.031952979
Apr-04	89,485,333	90,870,798	-1,385,465	1,385,465	0.015482594
May-04	90,686,143	90,306,901	379,242	379,242	0.004181915
Jun-04	96,517,444	94,679,765	1,837,680	1,837,680	0.019039869
Jul-04	110,297,642	106,992,251	3,305,391	3,305,391	0.029967924
Aug-04	109,063,695	108,308,306	755,390	755,390	0.006926132
Sep-04	103,094,592	96,923,445	6,171,147	6,171,147	0.059859079
Oct-04	93,329,246	92,318,553	1,010,693	1,010,693	0.010829324
Nov-04	94,434,399	92,530,823	1,903,576	1,903,576	0.020157653
Dec-04	108,483,621	106,213,850	2,269,771	2,269,771	0.020922704
Jan-05	111,357,551	109,438,481	1,919,070	1,919,070	0.017233407
Feb-05	97,354,644	98,242,916	-888,272	888,272	0.009124083
Mar-05	103,696,307	101,936,206	1,760,101	1,760,101	0.016973614
Apr-05	91,002,648	93,771,375	-2,768,727	2,768,727	0.030424684
May-05	90,914,555	93,862,538	-2,947,983	2,947,983	0.032425867
Jun-05	117,110,314	112,238,553	4,871,760	4,871,760	0.041599754
Jul-05	130,492,623	129,713,705	778,918	778,918	0.005969056
Aug-05	125,304,430	126,521,615	-1,217,185	1,217,185	0.009713822
Sep-05	103,515,709	101,668,383	1,847,327	1,847,327	0.017845858
Oct-05	95,683,703	97,627,082	-1,943,379	1,943,379	0.020310448

Nov-05	95,832,424	95,963,100	-130,676	130,676	0.00136359
Dec-05	109,926,431	110,738,844	-812,413	812,413	0.007390514
Jan-06	105,189,786	108,044,434	-2,854,648	2,854,648	0.027138072
Feb-06	97,673,987	100,381,767	-2,707,780	2,707,780	0.027722631
Mar-06	102,138,407	102,268,919	-130,511	130,511	0.001277789
Apr-06	89,654,385	94,878,724	-5,224,338	5,224,338	0.058271977
May-06	96,375,371	99,690,366	-3,314,995	3,314,995	0.034396707
Jun-06	106,149,796	106,208,823	-59,027	59,027	0.000556077
Jul-06	129,944,898	128,324,395	1,620,503	1,620,503	0.012470692
Aug-06	120,333,539	116,310,045	4,023,494	4,023,494	0.03343618
Sep-06	95,914,535	92,631,096	3,283,439	3,283,439	0.034232963
Oct-06	99,436,287	96,912,111	2,524,176	2,524,176	0.025384855
Nov-06	98,699,343	96,531,056	2,168,287	2,168,287	0.021968609
Dec-06	106,547,506	107,251,527	-704,020	704,020	0.006607573
Jan-07	110,076,804	110,275,202	-198,398	198,398	0.001802357
Feb-07	106,214,903	103,464,856	2,750,047	2,750,047	0.025891352
Mar-07	105,901,314	103,718,162	2,183,152	2,183,152	0.020614963
Apr-07	96,871,140	97,175,531	-304,391	304,391	0.003142229
May-07	96,387,835	97,908,860	-1,521,025	1,521,025	0.015780263
Jun-07	113,036,516	109,805,575	3,230,941	3,230,941	0.028583163
Jul-07	116,239,482	117,746,649	-1,507,167	1,507,167	0.01296605
Aug-07	124,879,950	124,368,063	511,887	511,887	0.004099032
Sep-07	104,023,176	99,671,729	4,351,447	4,351,447	0.041831512
Oct-07	99,226,202	98,044,554	1,181,648	1,181,648	0.011908628
Nov-07	100,079,144	97,850,024	2,229,120	2,229,120	0.022273574
Dec-07	110,979,900	110,348,651	631,249	631,249	0.005687962
Jan-08	109,510,859	110,253,962	-743,103	743,103	0.006785656
Feb-08	104,696,663	105,268,501	-571,838	571,838	0.005461855
Mar-08	105,342,397	104,701,766	640,631	640,631	0.006081413
Apr-08	86,729,774	95,971,708	-9,241,935	9,241,935	0.106560116
May-08	95,591,327	96,275,702	-684,375	684,375	0.007159383
Jun-08	106,359,072	106,705,484	-346,413	346,413	0.00325701
Jul-08	120,281,441	119,080,723	1,200,718	1,200,718	0.009982573
Aug-08	112,894,871	113,464,430	-569,559	569,559	0.00504504
Sep-08	101,394,552	97,273,034	4,121,519	4,121,519	0.040648323
Oct-08	95,461,113	96,640,057	-1,178,944	1,178,944	0.012349995
Nov-08	97,537,061	98,679,080	-1,142,019	1,142,019	0.011708566
Dec-08	111,556,941	111,528,922	28,020	28,020	0.000251171
Jan-09	117,644,799	113,852,701	3,792,098	3,792,098	0.032233449
Feb-09	97,575,928	100,444,296	-2,868,367	2,868,367	0.029396258
Mar-09	101,971,897	103,192,824	-1,220,927	1,220,927	0.011973172
Apr-09	92,172,703	95,486,144	-3,313,441	3,313,441	0.03594818
May-09	90,679,049	95,160,359	-4,481,310	4,481,310	0.049419462
Jun-09	97,810,557	100,756,078	-2,945,520	2,945,520	0.030114543
Jul-09	106,317,706	106,505,760	-188,055	188,055	0.001768798
Aug-09	118,314,176	118,315,788	-1,612	1,612	1.36278E-05
Sep-09	96,760,283	93,732,912	3,027,371	3,027,371	0.031287332
Oct-09	93,898,385	95,507,077	-1,608,692	1,608,692	0.01713226
Nov-09	93,733,129	94,267,884	-534,755	534,755	0.00570508
Dec-09	109,929,208	108,177,264	1,751,944	1,751,944	0.015937023
Jan-10	112,728,743	110,264,006	2,464,738	2,464,738	0.021864323
Feb-10	99,258,445	99,172,103	86,342	86,342	0.000869872
Mar-10	100,040,210	100,139,889	-99,678	99,678	0.000996381
Apr-10	89,357,236	93,034,422	-3,677,186	3,677,186	0.041151516
May-10	98,050,856	97,464,069	586,787	586,787	0.005984514

Jun-10	106,969,130	104,483,413	2,485,717	2,485,717	0.023237702
Jul-10	130,192,001	129,149,267	1,042,734	1,042,734	0.008009201
Aug-10	125,435,396	123,699,000	1,736,396	1,736,396	0.013842954
Sep-10	99,514,707	96,661,149	2,853,558	2,853,558	0.028674736
Oct-10	94,152,765	95,951,707	-1,798,941	1,798,941	0.019106624
Nov-10	97,120,412	96,082,428	1,037,985	1,037,985	0.010687604
Dec-10	111,894,733	110,349,420	1,545,314	1,545,314	0.013810422
Jan-11	113,829,885	112,321,926	1,507,959	1,507,959	0.013247478
Feb-11	102,120,252	101,177,386	942,866	942,866	0.009232902
Mar-11	106,849,783	103,563,676	3,286,106	3,286,106	0.03075445
Apr-11	94,087,029	96,272,661	-2,185,632	2,185,632	0.023229896
May-11	95,311,649	96,315,689	-1,004,040	1,004,040	0.010534279
Jun-11	104,481,388	101,919,787	2,561,601	2,561,601	0.024517294
Jul-11	132,315,624	134,164,484	-1,848,859	1,848,859	0.013973099
Aug-11	120,979,110	124,434,721	-3,455,611	3,455,611	0.028563702
Sep-11	101,456,692	96,488,314	4,968,379	4,968,379	0.048970438
Oct-11	95,202,185	96,292,694	-1,090,509	1,090,509	0.011454665
Nov-11	94,439,501	94,921,488	-481,987	481,987	0.005103655
Dec-11	105,238,563	107,336,048	-2,097,484	2,097,484	0.019930757
Jan-12	109,223,578	109,510,645	-287,067	287,067	0.002628249
Feb-12	99,573,605	101,884,379	-2,310,774	2,310,774	0.023206689
Mar-12	96,940,329	99,759,652	-2,819,323	2,819,323	0.02908308
Apr-12	90,395,437	95,103,935	-4,708,498	4,708,498	0.052087785
May-12	100,200,864	97,628,162	2,572,702	2,572,702	0.025675448
Jun-12	110,427,096	113,922,951	-3,495,855	3,495,855	0.031657588
Jul-12	134,019,462	135,176,122	-1,156,660	1,156,660	0.008630534
Aug-12	122,137,537	124,577,176	-2,439,640	2,439,640	0.01997453
Sep-12	100,247,713	98,368,179	1,879,534	1,879,534	0.0187489
Oct-12	95,198,440	95,708,608	-510,168	510,168	0.005358995
Nov-12	97,032,089	96,712,694	319,395	319,395	0.003291646
Dec-12	105,393,299	106,787,851	-1,394,551	1,394,551	0.013231878
Jan-13	110,317,098	108,991,277	1,325,821	1,325,821	0.012018272
Feb-13	99,792,260	100,302,482	-510,222	510,222	0.005112845
Mar-13	103,236,304	102,431,249	805,055	805,055	0.007798173
Apr-13	93,025,731	95,419,687	-2,393,956	2,393,956	0.025734345
May-13	96,420,692	96,547,152	-126,460	126,460	0.001311549
Jun-13	102,784,126	102,478,331	305,795	305,795	0.002975119
Jul-13	124,839,640	121,969,826	2,869,813	2,869,813	0.022987997
Aug-13	115,518,135	115,447,917	70,219	70,219	0.000607858
Sep-13	98,240,610	94,579,143	3,661,467	3,661,467	0.037270398
Oct-13	95,936,957	94,293,840	1,643,117	1,643,117	0.01712705
Nov-13	99,297,938	96,268,335	3,029,603	3,029,603	0.030510232
Dec-13	110,590,590	108,847,267	1,743,323	1,743,323	0.015763752

n = # observations	144
MAPE	**1.90%**


Actual vs. Predicted (GWh)
1,300
1,250
1,200
1,150
1,100
1,050
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Actual
Predicted



Actual vs Predicted by Month(kWh)
140,000,000
130,000,000
120,000,000
110,000,000
100,000,000
90,000,000
80,000,000
Jan-02
Apr-02
Jul-02
Oct-02
Jan-03
Apr-03
Jul-03
Oct-03
Jan-04
Apr-04
Jul-04
Oct-04
Jan-05
Apr-05
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Apr-11
Jul-11
Oct-11
Jan-12
Apr-12
Jul-12
Oct-12
Jan-13
Apr-13
Jul-13
Oct-13
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Actual
Predicted

APPENDIX L

NPEI CDM Activity Summary

CDM Activity Summary

For the years 2013 and 2014, the results are forecast based on the amounts necessary for NPEI to meet its four year licensed CDM kWh target of 58,000,000 kWh by the end of 2014. At this time, the nature of what CDM initiatives will be offered to NPEI's customers in 2015 is not yet clear. In the absence of detail on 2015 CDM programs, NPEI has estimated CDM activity from new initiatives in 2015 as 2.9 million kWh, which is 5% of NPEI's 58 million kWh four-year target from 2011 to 2014. At the time that NPEI prepared its weather normalized load forecast, the 2015 – 2020 CDM targets had not yet been published.

Methodology for Implementing CDM Explanatory Variable,
as per Board Staff Interrogatory #22, London Hydro COS Application EB-2012-0146/EB-2012-0380

Year	Reported Savings (kWh)	Incremental Savings (Reported Savings less Prior Year)	First Year (Half of Incremental Savings)	Monthly Increment (Year/78)
2006	4,211,271	4,211,271	2,105,636	26,995
2007	7,800,592	3,589,321	1,794,660	23,008
2008	9,396,789	1,596,197	798,099	10,232
2009	13,106,362	3,709,573	1,854,786	23,779
2010	14,225,868	1,119,506	559,753	7,176
2011	17,860,867	3,634,999	1,817,499	23,301
2012	23,164,672	5,303,805	2,651,903	33,999
2013	30,183,942	7,019,270	3,509,635	44,995
2014	36,443,378	6,259,435	3,129,718	40,125
2015	36,522,714	79,337	39,668	509

Based on 2012 Final Report

	4 Year (2011-2014) kWh Target: 58,000,000				
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	8.67%	8.67%	8.45%	7.93%	33.71%
2012 CDM Programs		9.68%	9.68%	9.48%	28.85%
2013 CDM Programs			12.48%	12.48%	24.96%
2014 CDM Programs				12.48%	12.48%
Total in Year	**8.67%**	**18.35%**	**30.61%**	**42.37%**	**100.00%**
		kWh			
2011 CDM Programs	5,026,978.00	5,026,978.00	4,900,000.00	4,600,000.00	19,553,956.00
2012 CDM Programs		5,615,949.00	5,615,949.00	5,500,000.00	16,731,898.00
2013 CDM Programs			7,238,048.67	7,238,048.67	14,476,097.33
2014 CDM Programs				7,238,048.67	7,238,048.67
Total in Year	**5,026,978.00**	**10,642,927.00**	**17,753,997.67**	**24,576,097.33**	**58,000,000.00**

NPEI CDM Programs
Net Energy Savings (MWh)
As reported by the OPA (Annualized Basis)

		Effect in Year									
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Year Initiated	**2006**	4,211	4,211	4,211	4,211	731	731	669	669	629	629
	2007		3,589	2,152	1,974	1,974	1,973	1,908	1,908	1,908	653
	2008			3,033	2,473	2,473	2,473	2,297	2,297	2,113	1,976
	2009				4,448	3,613	3,613	3,611	3,522	3,287	3,045
	2010					5,435	4,043	4,037	4,035	3,930	3,511
	2011						5,027	5,027	4,900	4,600	4,318
	2012							5,616	5,616	5,500	5,163
	2013								7,238	7,238	7,089
	2014									7,238	7,238
	2015										2,900
	Total	4,211	7,801	9,397	13,106	14,226	17,861	23,165	30,184	36,443	36,523

APPENDIX M

2010 to 2014 Project Narratives

Niagara Peninsula Energy Inc

Capital Project Summary

Historical Years

2010 - 2014

System Access

Project #	2010-0009	Reference #	SA-41
I. General Information			
Project Title	Kalar Rd. Catalina to Beaverdams	*Project Number*	2010-0009
Year	2010	*Service Area*	Niagara Falls
Total Capital Cost	$164,362	*Category*	System Access

II. Project Description

Description

The rebuild of 400 meters of existing double circuit between Catalina Dr. and Lundy's Lane and 800 meters of existing single circuit 3-phase 15 KV pole line between Lundy's Lane and Beaverdams Road. 1200 meters of new double circuit concrete pole line will be built on the West side of Kalar Road using the KM3 and KM7 Feeders between Lundy's & Beaverdams. Construction is required due to conflicts with CNF road widening works and the need for additional circuit intertie capabilities between Kalar M.T.S. and Stanley T.S. Additional intertie capability will improve feeder load balancing and contingency capabilities.

Map Overview

Evaluation Criteria
Reliability/Peforrmance: Extension of Kalar TS circuits will provide additional intertie capability with Stanley TS providing additional backfeed capability during contingencies. **Efficiency:** Additional circuit tie's will reduce response and restoration times in outage scenarios. Double circuit construction will consist of concrete poles were are less susceptible to deterioration issues. The single circuit is 15kV circuit is being upgraded to 556 kcMIL conductor which will reduce system losses. **Safety:** Existing wood poles on Kalar Rd. will be replaced with concrete poles with point of attachment at increased height. This will increase public and worker safety in the area. **Community Relations:** Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area. Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant.
Drivers
• **Municipal Road Works** • **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2010-0016	Reference #	SA-39

I. General Information

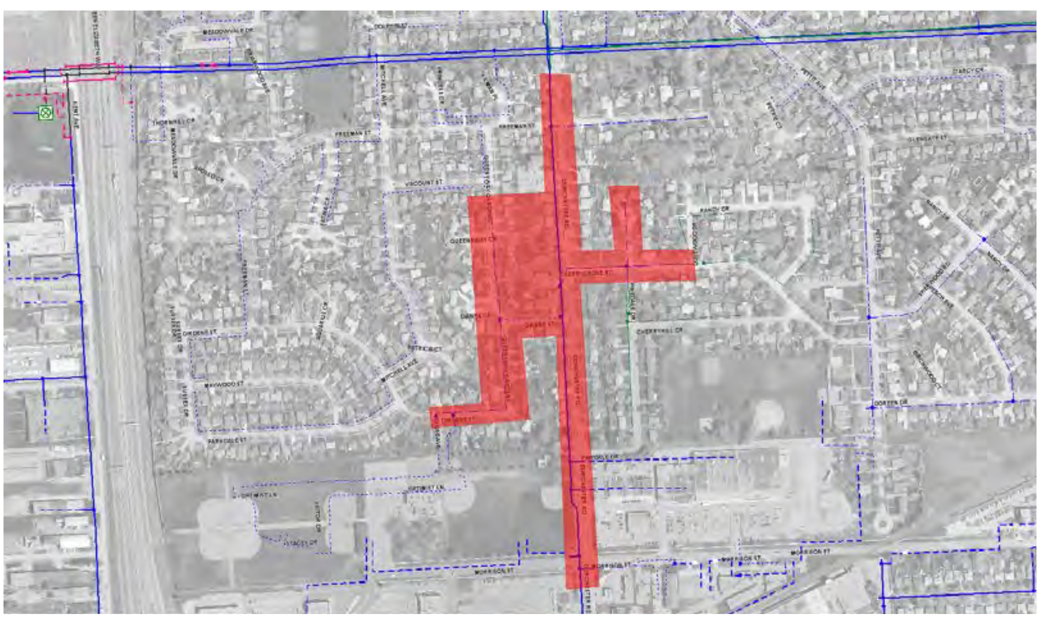
Project Title	**Side Streets of Dorchester Rd. from the N.S.&T. ROW to Morrison**	*Project Number*	**2010-0016**
Year	**2010**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$180,976**	*Category*	**System Access**

II. Project Description

Description

Due to the age and clearance issues between the 4.16 KV and 13.8KV circuits in this area it is necessary to eliminate the three-phase overhead spun 5KV cable along Dorchester Road. The load from this line will be transferred to the existing 12M32 distribution circuit by the placement of two pole mounted step down transformers along Cherrygrove. There will also be a small rebuild/conversion of line will on Dianne/Queensway Gardens. The spun primary cable will then be removed from the existing poles on Dorchester which will remain in service until the CNF finalizes the road widening design.

Map Overview



Evaluation Criteria
Reliability/Performance: The spun primary cable on Dorchester Rd. is at end of life. Removal of this conductor and conversion to the 13.8kV source on Dorchester Rd. improves overall reliability in the area. **Efficiency:** This projects positions NPEI to minimize conflicts with the municipality for planned future road works. Conversion of 4.16kV loads supplied from Virginia DS will reduce distribution losses. **Safety:** The existing wood poles on Dorchester Rd. are classed insufficiently to carry existing NPEI conductors and joint use based on existing standards. Removal of the heavily weighted primary cables from these poles greatly reduces the possibility of structural failure. **Community Relations:** Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers. Removal of deteriorated poles and large bundled primary conductor improves overall aesthetics of NPEI plant in the area.
Drivers
• **Municipal Road Works** • **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2010-0026	Reference #	SA-49

I. General Information

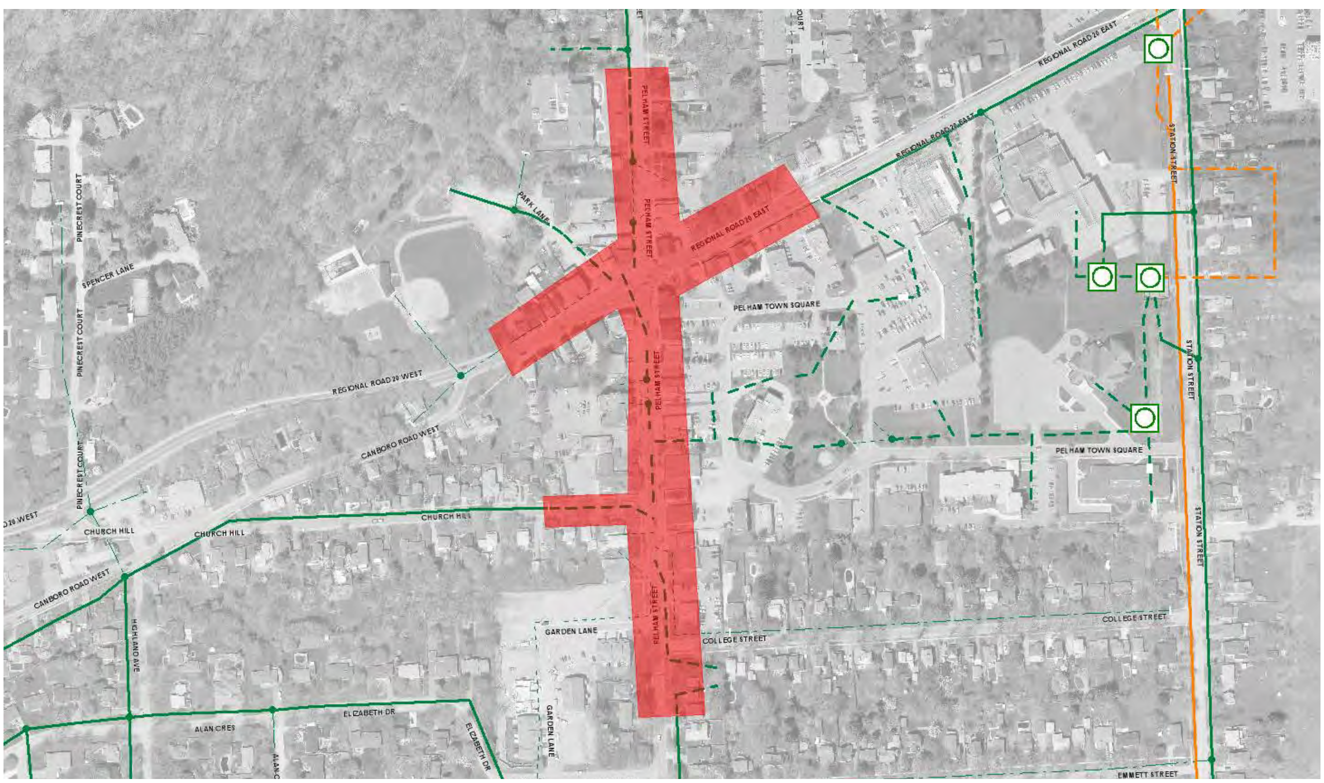
Project Title	**South Pelham St. - Fonthill Downtown Betterment**	***Project Number***	**2010-0026**
Year	**2010**	***Service Area***	**Fonthill**
Total Capital Cost	**$816,593**	***Category***	**System Access**

II. Project Description

Description

Scope involves the replacement of 500 meters of existing 3-phase overhead 5kV distribution feeder F5 in downtown Fonthill. Construction is required due to conflicts with municipal road widening/improvement works. A combination of overhead and underground distribution plant will be installed based on final negotiations with the municipality.

Map Overview



Evaluation Criteria
Reliability/Performance: Conversion of overhead lines to underground distribution minimizes exposure to foreign interference and lightning. **Efficiency:** This project is in conjunction with road works in the Town of Pelham (Fonthill). Coordination of civil works with the municipality duplication of resources. **Safety:** Many of the exiting wood poles on Pehlam St. and the attached spaced aerial cables are approaching end of life. Conversion of facilities to underground distribution in an urban setting improves overall safety to workers and public. **Community Relations:** Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers. Removal of deteriorated poles and spaced aerial conductor improves overall aesthetics of NPEI plant in the area.
Drivers
• **Municipal Road Works** • **Reliability** • **Safety** • **Efficiency**

Project #	2010-0053	Reference #	

I. General Information

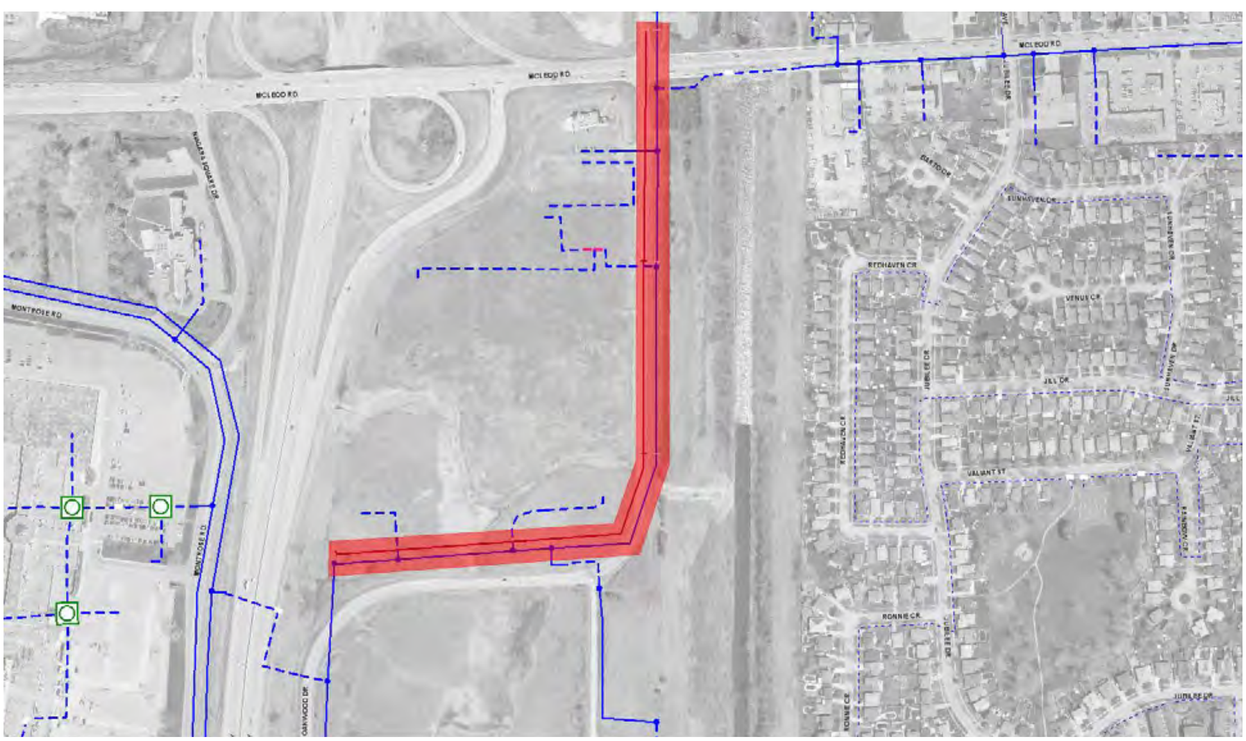
Project Title	**Oakwood Drive - Smart Center Line Relocate**	***Project Number***	**2010-0053**
Year	**2010**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$159,399**	***Category***	**System Access**

II. Project Description

Description

Scope of work involves the replacement of 800 meters of existing 3M30 15kV single circuit 3-phase pole line with a double circuit pole line using the KM6 and KM2 feeders. Construction is required due to construction conflicts with the Smart Centre road works, and system requirements for additional circuit intertie.

Map Overview



Evaluation Criteria
Reliability/Performance: Extension of the KM2, KM6 circuits provides intertie capability between Murray TS and Kalar TS. The additional circuits provide a back up supply and redundancy for surrounding customers in the area. This reduces overall circuit exposure on connected circuits. **Efficiency:** Loss reduction will result from re-directing commercial loads in the area to Kalar TS circuits as the normal source of supply. The length of line to the load center will significantly less when supplied from Kalar TS. **Safety:** Existing poles on Oakwood Dr. are nearing end of life. These will be eliminated as a result of this project and replaced with a higher class, concrete pole. This will increase public and worker safety in the area. **Community Relations:** Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area. Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant present in the area.
Drivers
• **Municipal Road Works** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2010-1008,1009,Various	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	*Project Number*	**2010-1008, 1009, Various**
Year	**2010**	*Service Area*	**All**
Total Capital Cost	**$435,393 $161,656 $331,699**	*Category*	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2010-Various	Reference #	SR-43

I. General Information

Project Title	Line Relocation due to Municipal Works (Less Than Materiality)	*Project Number*	2010-Various
Year	2010	*Service Area*	All
Total Capital Cost	$472,209	*Category*	System Access

II. Project Description

Description

There are various small projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2010-Various	Reference #	

I. General Information

Project Title	Subdivision - Distribution System Expansion	*Project Number*	2010-1009
Year	2010	*Service Area*	All
Total Capital Cost	$682,340	*Category*	System Access

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2011-0009	Reference #	SA-41
I. General Information			
Project Title	Carry Over - Kalar Rd. Catalina to Beaverdams	*Project Number*	2011-0009
Year	2011	*Service Area*	Niagara Falls
Total Capital Cost	$483,044	*Category*	System Access
II. Project Description			
Description			
See 2010 Project Description			
Map Overview			
See 2010 Map Overview			
Evaluation Criteria			
See 2010 Evaluation Criteria			
Drivers			
See 2010 Drivers			

Project #	2011-1008,1009,Various	Reference #	SA-42
I. General Information			
Project Title	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	*Project Number*	2011-1008, 1009, Various
Year	2011	*Service Area*	All
Total Capital Cost	$573,712 $389,962 $458,414	*Category*	System Access

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2011-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works (Less Than Materiality)**	*Project Number*	**2011-Various**
Year	**2011**	*Service Area*	**All**
Total Capital Cost	**$295,727**	*Category*	**System Access**

II. Project Description

Description

There are various small projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	**2011-Various**	**Reference #**	
I. General Information			
Project Title	**Subdivision - Distribution System Expansion**	***Project Number***	**2011-1009**
Year	**2011**	***Service Area***	**All**
Total Capital Cost	**$290,295**	***Category***	**System Access**
II. Project Description			
Description			
This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.			
Map Overview			
N/A			
Evaluation Criteria			
Reliability/Performance: N/A **Efficiency:** N/A **Safety:** N/A **Community Relations:** N/A			
Drivers			
• **Distribution system expansion** • **Connection of new residential customers**			

Project #	2011-0072	Reference #	SA-40

I. General Information

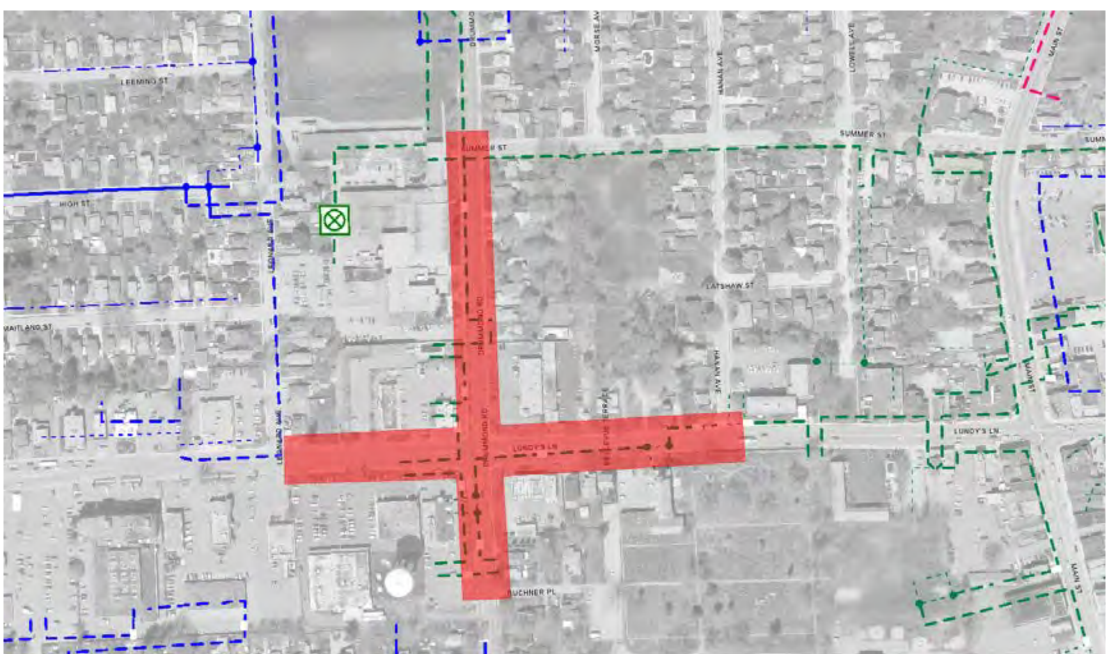
Project Title	**Drummond and Lundy's Lane Conflicts**	*Project Number*	**2011-0072**
Year	**2012**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$267,123**	*Category*	**System Access**

II. Project Description

Description

Scope of work involves the removal of legacy 4.16kV underground conductor, kiosks, and associated equipment. The legacy facilities will be replaced with 15kV underground primary conductor and pad-mounted transformation. The installation of 15kV conductor will permit conversion of the area to the 13.8kV system in the future. Construction is required due to construction conflicts with regional road works at the intersection of Drummond Road and Lundy's Lane.

Map Overview



Evaluation Criteria
Reliability/Performance: Replacement of 4.16kV cable and kiosk switching enclosures nearing end of life will better reliability in the area. **Safety:** Existing kiosk installations do not adhere to current NPEI standards and are at end of life. Replacement of Kiosks with dead-front pad-mounted equipment improves public and worker safety. **Community Relations:** Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area. Removal of deteriorated kiosk structures and replacement with pad mounted enclosures improves overall aesthetics of NPEI plant present in the area.
Drivers
• **Municipal Road Works** • **Safety** • **Efficiency**

Project #	2012-1008,1009,Various	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	*Project Number*	**2012-1008, 1009, Various**
Year	**2012**	*Service Area*	**All**
Total Capital Cost	**$711,788 $269,890 $196,437**	*Category*	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2012-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works (Less Than Materiality)**	*Project Number*	**2012-Various**
Year	**2012**	*Service Area*	**All**
Total Capital Cost	**$236,975**	*Category*	**System Access**

II. Project Description

Description

There are various small projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2012-Various	Reference #	

I. General Information

Project Title	Subdivision - Distribution System Expansion	*Project Number*	2012-1009
Year	2012	*Service Area*	All
Total Capital Cost	$518,409	*Category*	System Access

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2013-0100	Reference #	SA-38
I. General Information			
Project Title	**Kalar Rd. Widening - Catalina to Rideau**	***Project Number***	**2013-0100**
Year	**2013**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$169,530**	***Category***	**System Access**
II. Project Description			

Description

Scope of work requires the removal of secondary service crossing poles which are in conflict with the municipalities road widening plan. The existing overhead secondary service crossings will be replaced with underground secondary conductor in conjunction with civil works to permit road construction.

Map Overview

Evaluation Criteria
Safety: Replacement of long spans of overhead secondary conductors to meet current standards eliminates the risk of foreign interference over a 4 lane roadway. **Community Relations:** Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area. The installation of underground secondary facilities improves overall aesthetics along the roadway.
Drivers
• **Municipal Road Works** • **Safety**

Project #	2013-1008,1009,Various	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	*Project Number*	**2013-1008, 1009, Various**
Year	**2013**	*Service Area*	**All**
Total Capital Cost	**$1,011,493 $177,811 $84,734**	*Category*	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2013-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works (Less Than Materiality)**	*Project Number*	**2013-Various**
Year	**2013**	*Service Area*	**All**
Total Capital Cost	**$355,572**	*Category*	**System Access**

II. Project Description

Description

There are various small projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2013-Various	Reference #	

I. General Information

Project Title	Subdivision - Distribution System Expansion	*Project Number*	2013-1009
Year	2013	*Service Area*	All
Total Capital Cost	$703,212	*Category*	System Access

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2014-1008	Reference #	SA-42

I. General Information

Project Title	Demand Based Reinforcements, Customer Connections, New/Upgrade Services	*Project Number*	2014-1008
Year	2014	*Service Area*	All
Total Capital Cost	$1,410,778	*Category*	System Access

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2014-Various	Reference #	SA-43

I. General Information

Project Title	Line Relocation due to Municipal Works (Less Than Materiality)	*Project Number*	2014-Various
Year	2014	*Service Area*	All
Total Capital Cost	$539,910	*Category*	System Access

II. Project Description

Description

There are various small projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2014-Various	Reference #	

I. General Information

Project Title	**Subdivision - Distribution System Expansion**	*Project Number*	**2014-1009**
Year	**2014**	*Service Area*	**All**
Total Capital Cost	**$400,000**	*Category*	**System Access**

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

System Renewal

Project #	2010-0017	Reference #	SR-10
I. General Information			
Project Title	Campden DS Feeder Egress	*Project Number*	2010-0017
Year	2010	*Service Area*	Niagara Falls
Total Capital Cost	$207,208	*Category*	System Renewal
II. Project Description			

Description

The annual pole testing inspection program has identified the requirement for the replacement of the poles outside Campden DS that support the incoming supply and distribution Feeders. This project has been isolated from the pole replacement program due to the complexity of the amount of equipment supported. Also to maintain proper working clearances and strain support. Construction standards will need to be developed for the framing required.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Pole Condition Survey - End of Life Assets**

Project #	2010-0025	Reference #	SR-4

I. General Information

Project Title	**Pelham MS Rebuild**	***Project Number***	**2010-0025**
Year	**2010**	***Service Area***	**Fonthill**
Total Capital Cost	**$226,046**	***Category***	**System Renewal**

II. Project Description

Description

Replacement of the 27.6/4.16 kV distribution station equipment supplying the Town of Fonthill. This work includes a new 27.6/8.32-4.16 kV 5000 KVA Transformer (which could be moved elsewhere on the system in the future), and new protection equipment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment - End of Life Assets**

Project #	2010-1007 & 2007	Reference #	SR-30

I. General Information

Project Title	System Sustainment / Minor Betterments	*Project Number*	2010-1007 & 2007
Year	2010	*Service Area*	All
Total Capital Cost	$1,008,971	*Category*	System Renewal

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

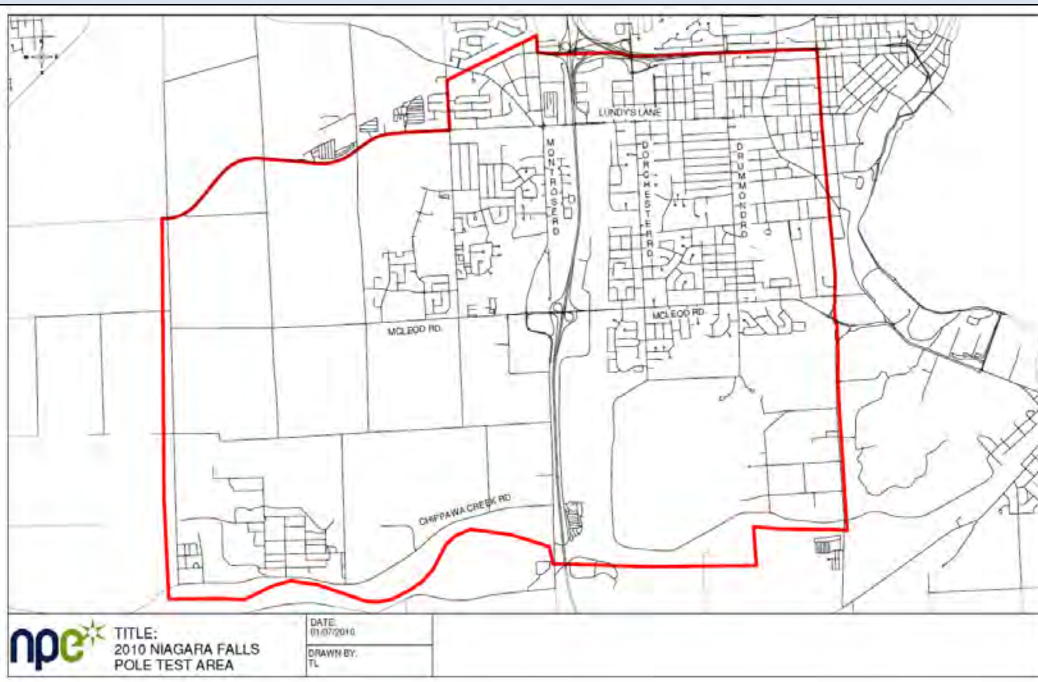
Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2010-1010 & 2010	Reference #	SR-31
I. General Information			
Project Title	**Pole Replacement Program**	***Project Number***	**2010-1010 & 2010**
Year	**2010**	***Service Area***	**All**
Total Capital Cost	**$788,664**	***Category***	**System Renewal**
II. Project Description			
Description			
Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The 2010 test area is bounded in the West by the City Limits, South to the Welland River, and East to Stanley Ave, North to Hwy #420/Beaverdams Road. Also included in the testing area is the Town of Fonthill. Based on the remainder of suspect poles stemming from prior inspection cycles, approximately 60 poles require immediate replacement, with approximately 150 poles reaching the "replace within 5-years" milestone within both service territories.			
Map Overview			



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment / Poles at End of Life**

Project #	2010-0020	Reference #	SR-32
I. General Information			
Project Title	**Kiosk/Submersible Replacement Program**	*Project Number*	**2010-0020**
Year	**2010**	*Service Area*	**All**
Total Capital Cost	**$501,362**	*Category*	**System Renewal**
II. Project Description			
Description			
The Kiosk replacement program is an integral part of our underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. At the current rate of replacement it will take approximately 10 years to complete this task. The locations are prioritized by the results of a Conditional Assessment Survey completed in 2008, which will be repeated on a 5-year cycle as required. 75 units remain on the 15kV system with 14 converted in 2009. 105units remain on the 5kV system with 6 converted in 2009. For 2010 the plan the program will replace approximately 20 units.			
Map Overview			
N/A			
Evaluation Criteria			
N/A			
Drivers			
• **Sustainment** • **Asset Condition Assessment /Equipment at End of Life**			

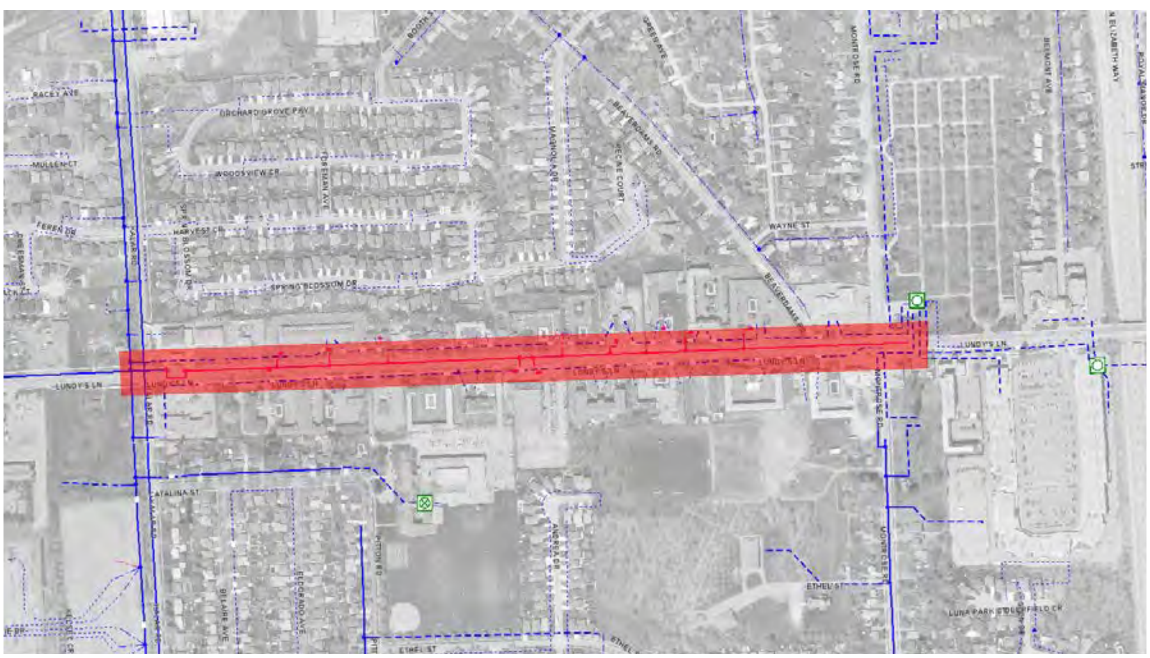
Project #	2011-0004	Reference #	SR-13
I. General Information			
Project Title	**Lundy's Lane Line Build - Montrose to Kalar**	*Project Number*	**2011-0004**
Year	**2011**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$156,213**	*Category*	**System Renewal**

II. Project Description

Description

The project scope includes the replacement of plant based upon preliminary design submissions for municipal consent in 2010 to replace the 1 km of directly buried underground feeder with an overhead pole line. Equipment replacements are required due to a number of cable faults experienced on this section of feeder, which is approaching end of life. The replacement includes extending the existing KM7 13.8kV 3-phase line on concrete poles on the North side of Lundy’s Lane between Kalar and Montrose Road.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Repeated Underground Cable Failures**

Project #	2011-0005	Reference #	SR-15

I. General Information

Project Title	**Riall Street Rebuild**	***Project Number***	**2011-0005**
Year	**2011**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$143,116**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of a section of existing directly buried 12M33 15kV underground primary cable from Stanley T.S. with an overhead pole line. Equipment replacements are required due to the plant approaching end of life. The project also includes the rebuild of an existing 4.16kV 3-phase pole line on the north side of Riall Street to 3-phase 13.8KV. The rebuild will replace the underground primary cable and eliminate a 4.16KV radial-feed providing an 8.0kV source to recently rebuilt lines between Riall & Stamford Green Drive.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Primary Cable at End of Life**

Project #	2011-0007	Reference #	SR-14

I. General Information

Project Title	Murray Street Area Rebuild - Bounded by Culp/Dunn/Main/Drummond	*Project Number*	2011-0007
Year	2011	*Service Area*	Niagara Falls
Total Capital Cost	$395,970	*Category*	System Renewal

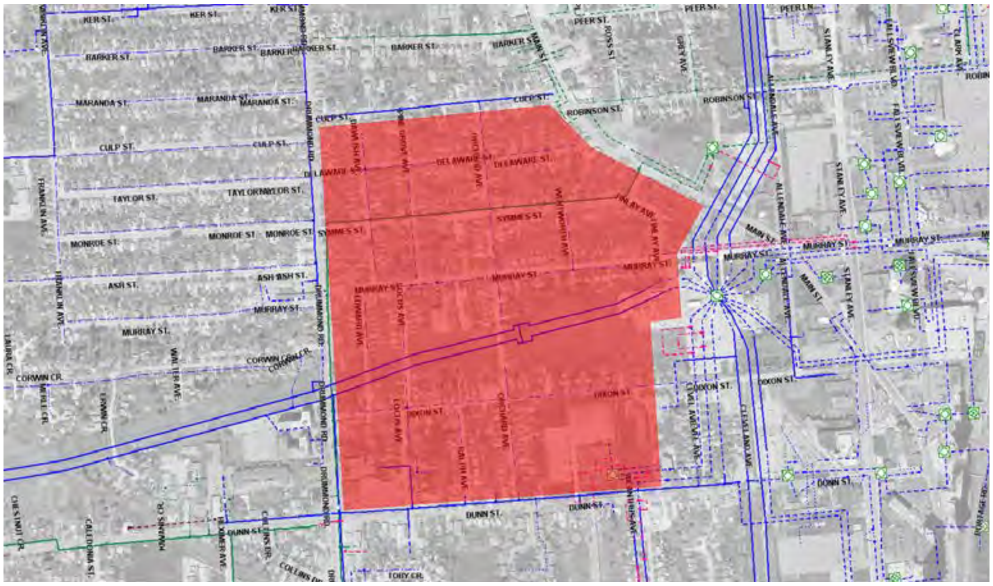
II. Project Description

Description

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2011 this program targets approximately 5 kilometers of urban distribution line requiring 150 pole changes, the installation of new single phase primary and secondary circuits, 30 distribution transformer replacements and results in upgraded supply to about 400 residential customers.

This multi-year project focuses on commencement of rebuild in the Murray Street area.

Map Overview



Evaluation Criteria

Reliability/Performance:

The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. New standards for single phase distribution incorporate covered primary conductor installed with an increase in the point of attachment. The covered conductor is capable of withstanding momentary tree contact without disruption of service.

Efficiency:

This area will be converted from 4.16kV to 13.8kV. Conversion of this area contributes to the elimination of two 4.16kV feeders. Both the feeder elimination and voltage conversion will contribute to a reduction in system losses.

Safety:

The project involves the replacement of poles at a substandard height. New construction includes the installation of 40' poles for the attachment of covered primary conductor. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact.

Community Relations:

Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.

Drivers

- **Sustainment**
- **Replacement of Assets at End of Life**

Project #	2011-0011	Reference #	SR-11
I. General Information			
Project Title	System Sectionalizing Devices	*Project Number*	2011-0011
Year	2011	*Service Area*	Niagara Falls
Total Capital Cost	$156,718	*Category*	System Renewal
II. Project Description			
Description			
The review of existing feeder configurations, which egress from Stanley & Murray T.S. & Kalar M.T.S. has identified the requirement for the installation of additional pole mounted ganged load break switches within the system to replace existing aerial operated single phase switches. The existing switches are in locations that intertie circuits This will provide greater capability to perform circuit sectionalizing during outage events in order to minimize the affected area.			
Map Overview			
N/A			
Evaluation Criteria			
N/A			
Drivers			
• Sustainment • Replacement of Assets at End of Life			

Project #	2011-0013	Reference #	SR-5

I. General Information

Project Title	**Smithville DS Rebuild**	***Project Number***	**2011-0013**
Year	**2011**	***Service Area***	**West Lincoln**
Total Capital Cost	**$361,959**	***Category***	**System Renewal**

II. Project Description

Description

Replacement of the 27.6/8.32kV distribution station equipment supplying portions of the area of Smithville. This work includes a new 27.6/8.32kV 5000 KVA transformer, new protection equipment, ground grid, and oil containment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment - End of Life Assets**

Project #	2011-0017	Reference #	SR-12

I. General Information

Project Title	**Campden DS Rebuild**	***Project Number***	**2011-0017**
Year	**2011**	***Service Area***	**Lincoln**
Total Capital Cost	**$214,586**	***Category***	**System Renewal**

II. Project Description

Description

Replacement of the distribution station protection equipment at Campden DS that supplies portions of the surrounding area of Campden. The existing transformer will continue to be utilized in the design based on results of the asset condition assessment. The scope of work includes a new protection equipment, ground grid, and oil containment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Replacement of Equipment at End of Life**

Project #	2011-0022	Reference #	SR-6

I. General Information

Project Title	Station St. DS Rebuild	*Project Number*	2011-0022
Year	2011	*Service Area*	Fonthill
Total Capital Cost	$41,711	*Category*	System Renewal

II. Project Description

Description

Replacement of the distribution station protection equipment at Station St. DS that supplies portions of town of Fonthill. The existing transformer will continue to be utilized in the design based on results of the asset condition assessment. The scope of work includes a new protection equipment and grounding. The existing LV protection equipment is of 1950's vintage and consists of oil circuit breakers in a confined space presenting numerous safety hazards for workers.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Replacement of Equipment at End of Life**

Project #	2011-1007 & 2007	Reference #	SR-30

I. General Information

Project Title	System Sustainment / Minor Betterments	*Project Number*	2011-1007 & 2007
Year	2011	*Service Area*	All
Total Capital Cost	$451,575	*Category*	System Renewal

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2011-1010 & 2010	Reference #	SR-31

I. General Information

Project Title	Pole Replacement Program	*Project Number*	2011-1010 & 2010
Year	2011	*Service Area*	All
Total Capital Cost	$826,302	*Category*	System Renewal

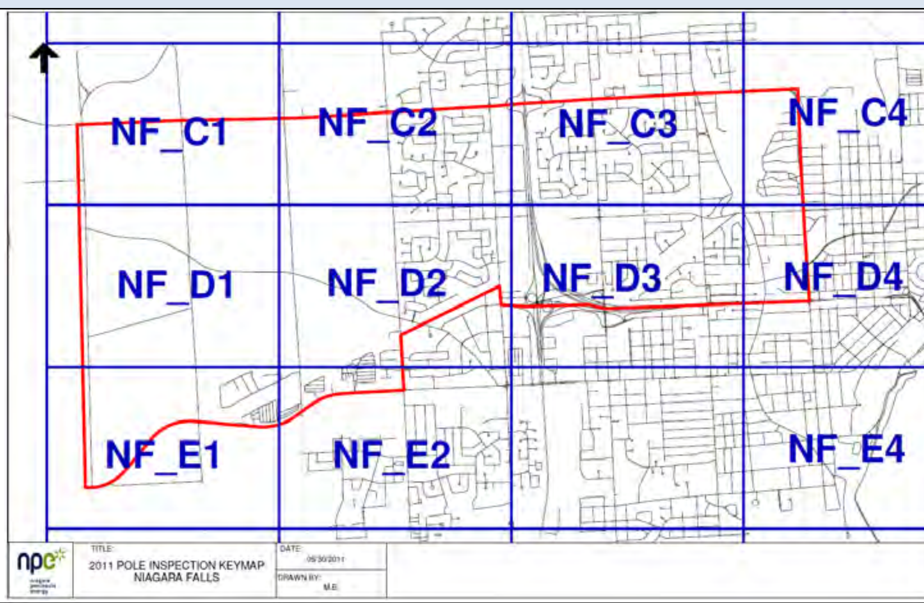
II. Project Description

Description

Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The 2011 test area in Niagara Falls is bounded in the West by the City Limits, South to the Hwy #420/Lundy's Lane, and East to Stanley Ave, North to Thorold Stone Road and all of the area south of the Welland River. Western Service Territory testing is in the area of Westbrook Road to the west, north to Twenty Road, East to Church/Allen Road, south to the Boundary line at South Chippawa Road.

Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.

Map Overview



Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment / Poles at End of Life**

Project #	2011-0020	Reference #	SR-32
I. General Information			
Project Title	**Kiosk/Submersible Replacement Program**	*Project Number*	**2011-0020**
Year	**2011**	*Service Area*	**All**
Total Capital Cost	**$508,036**	*Category*	**System Renewal**

II. Project Description

Description

The Kiosk replacement program is an integral part of our underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. The locations are prioritized by the results of a Conditional Assessment Survey completed in 2008, which will be repeated on a 5-year cycle as required.

71 units remain on the 15KV system with 4 were converted in 2010. 101 Units remain on the 5KV System 6 were converted in 2010. For 2011 the plan is to replace approximately 15 units.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2011-0005	Reference #	SR-15

I. General Information

Project Title	Carry Over - Riall Street Rebuild	*Project Number*	2011-0005
Year	2012	*Service Area*	Niagara Falls
Total Capital Cost	$357,948	*Category*	System Renewal

II. Project Description

Description

See 2011 Project Description

Map Overview

See 2011 Map Overview

Evaluation Criteria

See 2011 Evaluation Criteria

Drivers

See 2011 Drivers

Project #	2011-0013	Reference #	SR-5

I. General Information

Project Title	**Carry Over - Smithville DS Rebuild**	***Project Number***	**2011-0013**
Year	**2012**	***Service Area***	**West Lincoln**
Total Capital Cost	**$274,090**	***Category***	**System Renewal**

II. Project Description

Description

See 2011 Project Description

Map Overview

See 2011 Map Overview

Evaluation Criteria

See 2011 Evaluation Criteria

Drivers

See 2011 Drivers

Project #	2011-0022	Reference #	SR-6

I. General Information

Project Title	**Carry Over - Station St. DS Rebuild**	***Project Number***	**2011-0022**
Year	**2012**	***Service Area***	**Fonthill**
Total Capital Cost	**$137,209**	***Category***	**System Renewal**

II. Project Description

Description

See 2011 Project Description

Map Overview

See 2011 Map Overview

Evaluation Criteria

See 2011 Evaluation Criteria

Drivers

See 2011 Drivers

Project #	2012-0001	Reference #	SR-17

I. General Information

Project Title	**Montrose Rd. Rebuild Lundy's Lane to Kinsmen Court**	*Project Number*	**2012-0001**
Year	**2012**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$608,128**	*Category*	**System Renewal**

II. Project Description

Description

The project scope includes the replacement of 1.1km of existing overhead plant on the east side of Montrose Road with a new pole line in the same location. Replacements are required due to capacity limitations of the existing primary conductor, the requirement of a 600 Amp source to existing switching Station #28, and issues associated with existing underground distribution between Kalar and Montrose Road. The project includes an underground extension from the last pole south of Lundy's Lane to the switching station on the North East corner of Lundy's Lane and Montrose Road.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2012-0002	Reference #	SR-16

I. General Information

Project Title	**Lundy's Lane / Ker St. UG Distribution Replacement**	***Project Number***	**2012-0002**
Year	**2012**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$356,580**	***Category***	**System Renewal**

II. Project Description

Description

Replacement of existing directly buried underground distribution facilities approaching end of life. The distribution facilities have inherent operational issues of legacy construction. They are located within the commercial core between Drummond Road and Franklin Ave. The proposal includes the introduction of multiple points of supply from the recently rebuilt line on Ker Street. Construction includes a 450 meter long duct bank for extension of 200 Amp 13,800 Volt distribution feeders using the Murray Station 3M51. The construction will eliminate existing switchgear assemblies at Station #25, Station #53, Station #38, and Station #21, and enable a 13.8 KV source for future High St. voltage conversion.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of UG Distribution at End of Life**

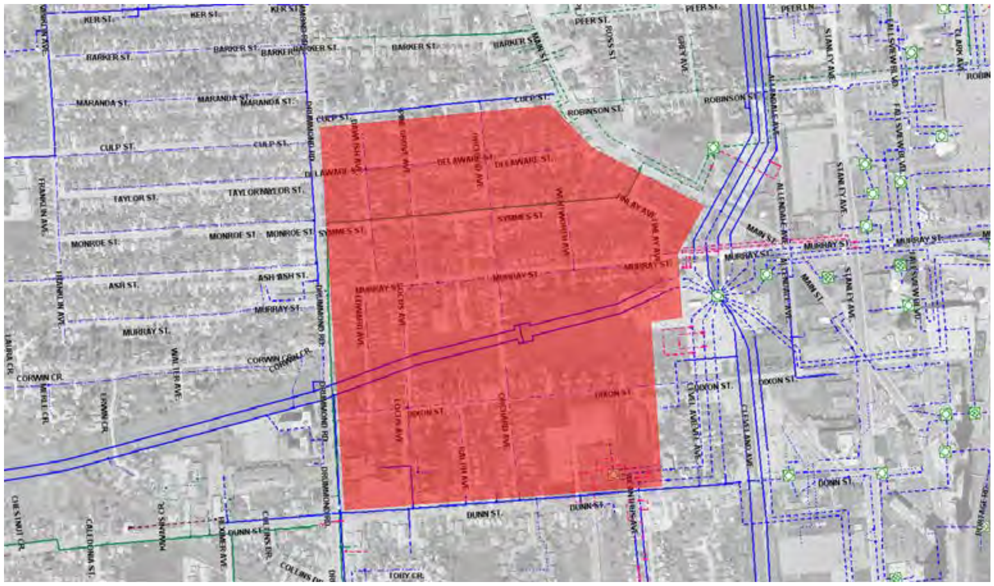
Project #	2012-0007	Reference #	SR-18
I. General Information			
Project Title	**Carry Over - Murray Street Area Rebuild - Bounded by Culp/Dunn/Main/Drummond**	*Project Number*	**2012-0007**
Year	**2012**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$633,981**	*Category*	**System Renewal**
II. Project Description			

Description

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2012 this program targets the remainder of approximately 5 kilometers of urban distribution line requiring 150 pole changes, the installation of new single phase primary and secondary circuits, 30 distribution transformer replacements and results in upgraded supply to about 400 residential customers.

This multi-year project focuses on commencement of rebuild in the Murray Street area.

Map Overview



Evaluation Criteria

Reliability/Performance:
The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. New standards for single phase distribution incorporate covered primary conductor installed with an increase in the point of attachment. The covered conductor is capable of withstanding momentary tree contact without disruption of service.

Efficiency:
This area will be converted from 4.16kV to 13.8kV. Conversion of this area contributes to the elimination of two 4.16kV feeders. Both the feeder elimination and voltage conversion will contribute to a reduction in system losses.

Safety:
The project involves the replacement of poles at a substandard height. New construction includes the installation of 40' poles for the attachment of covered primary conductor. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact.

Community Relations:
Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.

Drivers

- **Sustainment**
- **Replacement of Assets at End of Life**

Project #	2012-0012	Reference #	SR-6

I. General Information

Project Title	**Greenlane DS Rebuild**	***Project Number***	**2012-0012**
Year	**2012**	***Service Area***	**West Lincoln**
Total Capital Cost	**$275,300**	***Category***	**System Renewal**

II. Project Description

Description

Replacement of the 27.6/8.32kV distribution station equipment supplying portions of the area of Lincoln running along the QEW. This work includes a new 27.6/8.32kV 5000 KVA transformer, new protection equipment, ground grid, and oil containment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment - End of Life Assets**

Project #	2012-0014	Reference #	SR-19

I. General Information

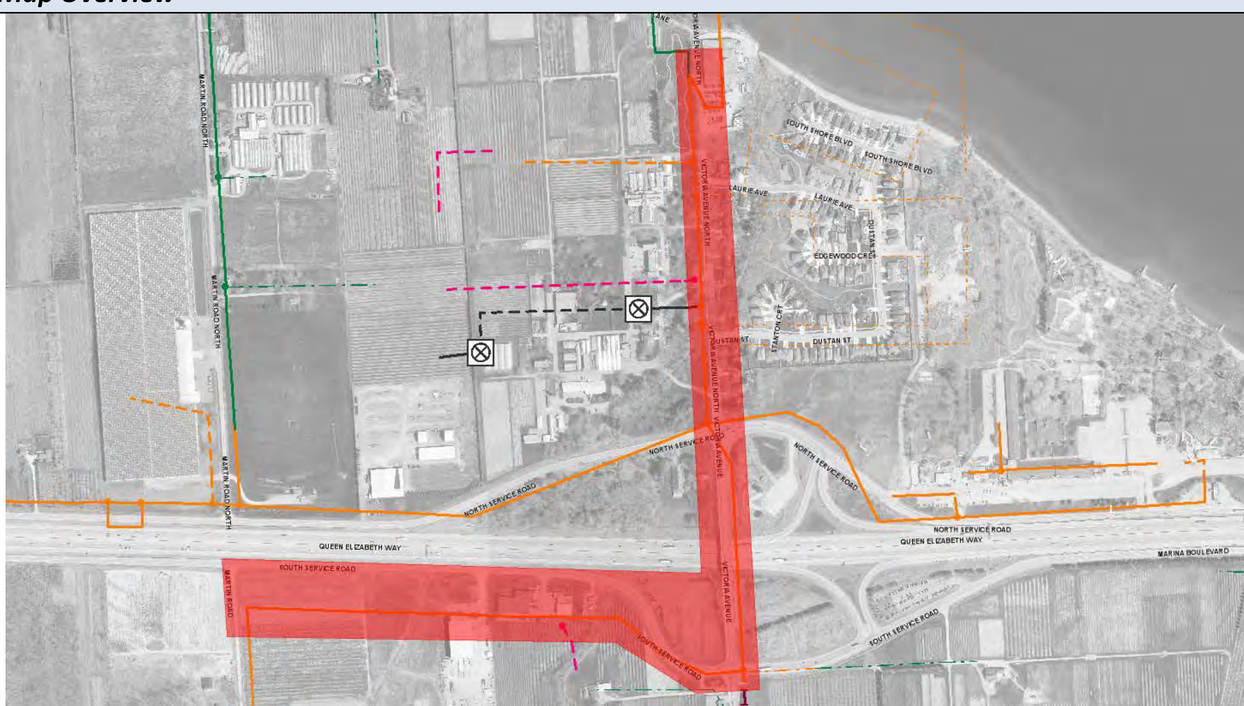
Project Title	**Victoria Ave. Voltage Conversion**	***Project Number***	**2012-0014**
Year	**2012**	***Service Area***	**Lincoln**
Total Capital Cost	**$173,042**	***Category***	**System Renewal**

II. Project Description

Description

The Project Scope involves the construction of approx 1km of new 3-phase pole line on the South Service Road. This includes conversion of an existing radial 8.32 KV section of F2 feeder fed from Greenlane D.S. to 27.6 KV on Victoria Avenue north of the Q.E.W. A good portion of the line on Victoria Ave had been previously re-built to 27.6KV insulation levels with dual voltage equipment.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2012-1007 & 2007	Reference #	SR-30

I. General Information

Project Title	**System Sustainment / Minor Betterments**	***Project Number***	**2012-1007 & 2007**
Year	**2012**	***Service Area***	**All**
Total Capital Cost	**$525,207**	***Category***	**System Renewal**

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2012-1010 & 2010	Reference #	SR-31
I. General Information			
Project Title	Pole Replacement Program	*Project Number*	2012-1010 & 2010
Year	2012	*Service Area*	All
Total Capital Cost	$862,338	*Category*	System Renewal

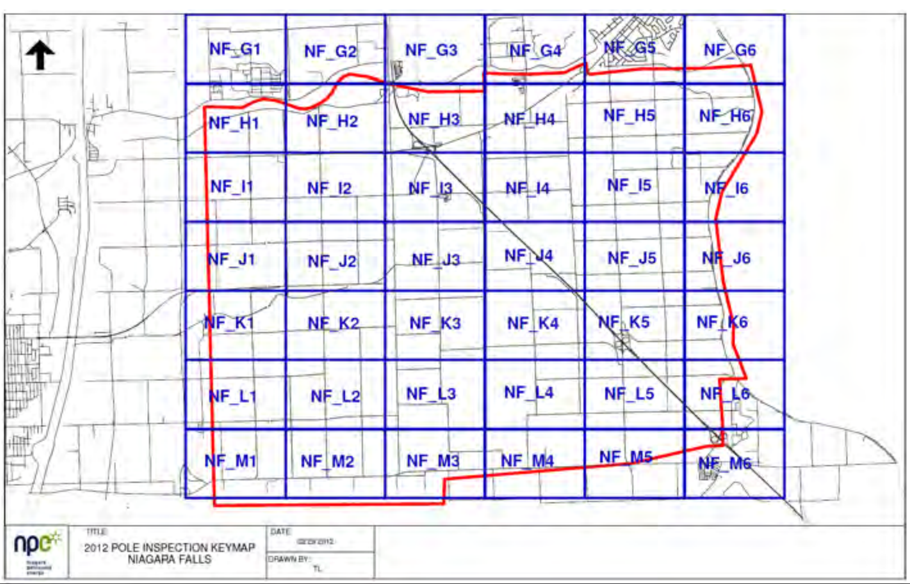
II. Project Description

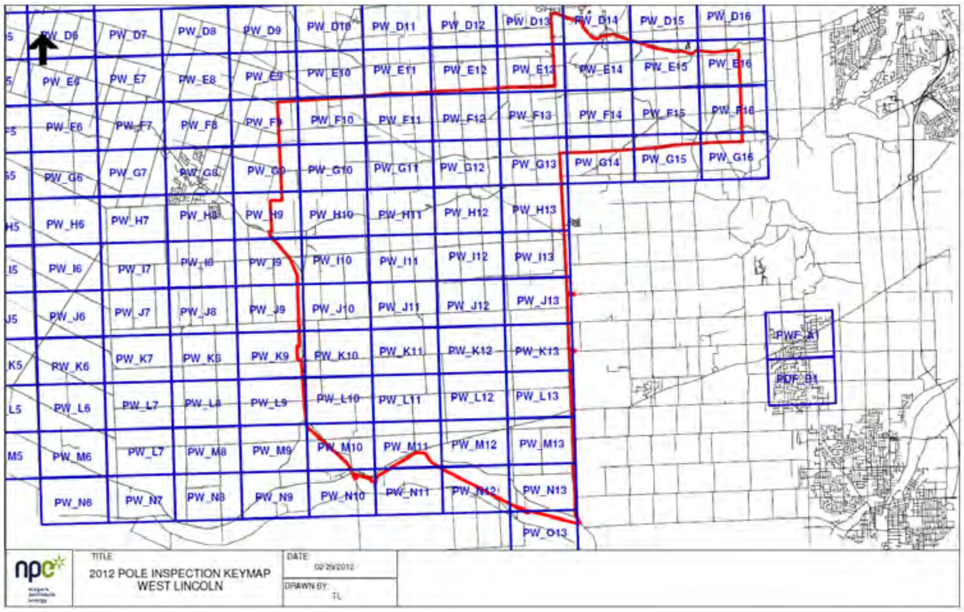
Description

Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The 2012 test area in Niagara Falls is bounded in the West by the Welland City Limits, South to the Fort Erie City Limits, East to the Niagara River, and North to the Welland River. Western Service Territory testing area is from Regional Road #20/#27 to the west, north to Fly Road, East to Victoria Avenue, south to the Boundary line at East Chippawa Road.

Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.

Map Overview





Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment / Poles at End of Life**

Project #	2012-0020	Reference #	SR-32
I. General Information			
Project Title	**Kiosk/Submersible Replacement Program**	*Project Number*	**2012-0020**
Year	**2012**	*Service Area*	**All**
Total Capital Cost	**$705,374**	*Category*	**System Renewal**

II. Project Description

Description

The Kiosk replacement program is an integral part of our underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. The locations are prioritized by the results of a Conditional Assessment Survey completed in 2008, which will be repeated on a 5-year cycle as required.

66 units remain on the 15kV System with 5 were converted in 2011. 88 units remain on the 5KV System with 13 were converted in 2011. For 2012 the plan is to replace approximately 15 units.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2011-0022	Reference #	SR-6
I. General Information			
Project Title	**Carry Over - Station St. DS Rebuild**	***Project Number***	**2011-0022**
Year	**2013**	***Service Area***	**Fonthill**
Total Capital Cost	**$100,331**	***Category***	**System Renewal**
II. Project Description			
Description			
See 2011 Project Description			
Map Overview			
See 2011 Map Overview			
Evaluation Criteria			
See 2011 Evaluation Criteria			
Drivers			
See 2011 Drivers			

Project #	2012-0012	Reference #	SR-6
I. General Information			
Project Title	**Carry Over - Greenlane DS Rebuild**	***Project Number***	**2012-0012**
Year	**2013**	***Service Area***	**West Lincoln**
Total Capital Cost	**$197,505**	***Category***	**System Renewal**
II. Project Description			
Description			
See 2012 Project Description			
Map Overview			
See 2012 Map Overview			
Evaluation Criteria			
See 2012 Evaluation Criteria			
Drivers			
See 2012 Drivers			

Project #	2012-0014	Reference #	SR-19

I. General Information

Project Title	Carry Over - Victoria Ave. Voltage Conversion	*Project Number*	2012-0014
Year	2013	*Service Area*	Lincoln
Total Capital Cost	$170,305	*Category*	System Renewal

II. Project Description

Description

See 2012 Project Description

Map Overview

See 2012 Map Overview

Evaluation Criteria

See 2012 Evaluation Criteria

Drivers

See 2012 Drivers

Project #	2013-0003	Reference #	SR-22

I. General Information

Project Title	**Weightman Bridge Underground Primary Extension**	*Project Number*	**2013-0003**
Year	**2013**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$113,001**	*Category*	**System Renewal**

II. Project Description

Description

The project scope involves the installation of approximately 230 meters of 600kcMIL underground primary cable within an existing duct structure placed during the bridge reconstruction. Also included are the construction of two primary risers and a recloser installation to minimize feeder exposure for upstream commercial loads. The project allows NPEI to deal with two existing overhead crossings over the Welland River which are approaching end of life.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2013-0005	Reference #	SR-1

I. General Information

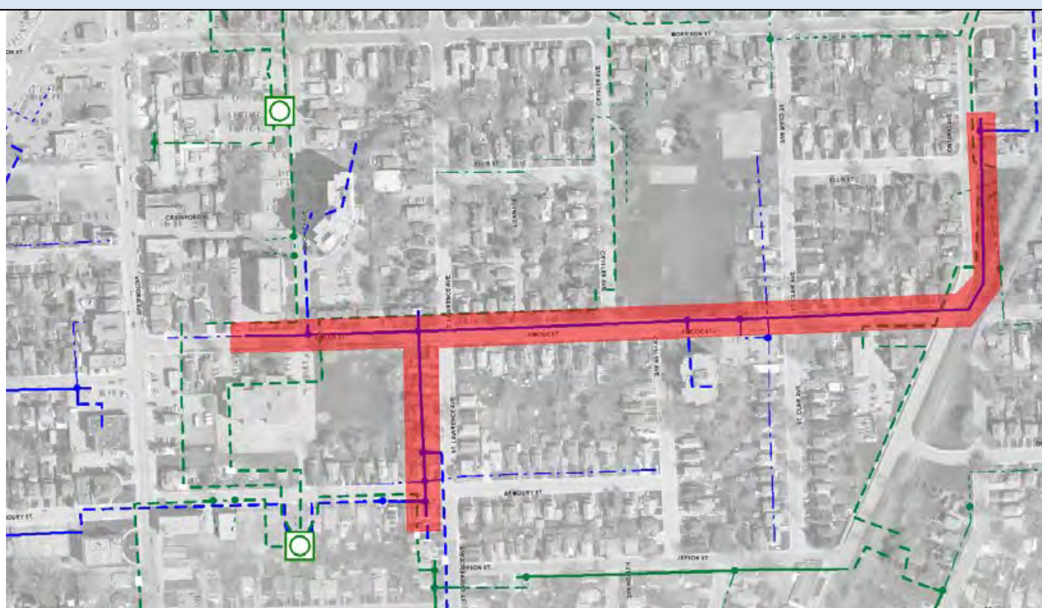
Project Title	12M6 Conductor Replacement Simcoe, Buckly, Armoury St. Area	*Project Number*	2013-0005
Year	2013	*Service Area*	Niagara Falls
Total Capital Cost	$538,747	*Category*	System Renewal

II. Project Description

Description

The project scope involves the replacement of a PILCDSTA underground primary cable installed in 1961 with a 50' wood pole line supporting a 556kcmil 3 phase tree conductor. The area of rebuild is on Simcoe St. from Buckley Ave to Palmer Ave, and St Lawrence Ave from Armoury St to Simcoe St. The pole line will be constructed in the same alignment as the existing 2.4KV single phase pole line currently in service. The project eliminates the aging cable, which has posed reliability issues due to splice failures, and provides immediate voltage conversion opportunities of several lateral feeds from the existing pole line. It also provides a source for future voltage conversion of Station #3 & Station #6 loads.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2013-0007	Reference #	SR-20

I. General Information

Project Title	**Carry Over - Murray Street Area Rebuild - Bounded by Culp/Dunn/Main/Drummond**	*Project Number*	**2013-0007**
Year	**2013**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$712,700**	*Category*	**System Renewal**

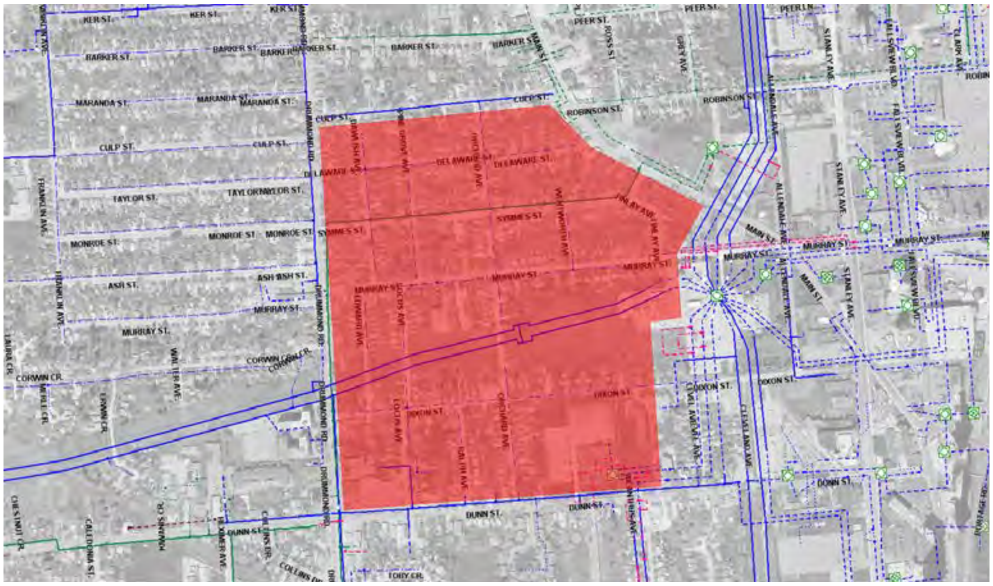
II. Project Description

Description

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2013 this program targets the remainder of the approximately 5 kilometers of urban distribution line requiring 150 pole changes, the installation of new single phase primary and secondary circuits, 30 distribution transformer replacements and results in upgraded supply to about 400 residential customers.

This multi-year project focuses on commencement of rebuild in the Murray Street area.

Map Overview



Evaluation Criteria

Reliability/Performance:

The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. New standards for single phase distribution incorporate covered primary conductor installed with an increase in the point of attachment. The covered conductor is capable of withstanding momentary tree contact without disruption of service.

Efficiency:

This area will be converted from 4.16kV to 13.8kV. Conversion of this area contributes to the elimination of two 4.16kV feeders. Both the feeder elimination and voltage conversion will contribute to a reduction in system losses.

Safety:

The project involves the replacement of poles at a substandard height. New construction includes the installation of 40' poles for the attachment of covered primary conductor. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact.

Community Relations:

Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.

Drivers

- **Sustainment**
- **Replacement of Assets at End of Life**

Project #	2013-0008	Reference #	SR-3

I. General Information

Project Title	**High Street Rebuild - Dorchester Road to Station #10**	***Project Number***	**2013-0008**
Year	**2013**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$633,880**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves replacement of 1.2km of existing overhead double circuit 4.16kV line (F101 and F102) with a 15 KV single circuit 3-phase line (3M51) on 50’ poles between Dorchester Rd. and Leonard Ave. It includes an underground structure between High St. and Station #10. The new poles will maintain the alignment of the existing 4.16KV poles. The construction facilitates conversion of laterals rebuilt on the side streets within recent years. System benefits include replacement of aging equipment, improved equipment clearances. It also contributes to load reduction on Municipal Substations #10 & #22 with conversion of the laterals.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2013-0011	Reference #	SR-2

I. General Information

Project Title	**Dorchester Rebuild - Garden to McMillan**	*Project Number*	**2013-0011**
Year	**2013**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$198,807**	*Category*	**System Renewal**

II. Project Description

Description

Project scope involves replacement of 1.5km of existing overhead single circuit 5kV line (F222) with a 15kV single circuit 3-phase line (KM4) on 50' poles on Dorchester Rd. between Garden St & McMillan Dr. The poles will maintain the same alignment as the existing 4.16kV pole line currently in service. System benefits include the replacement of aging equipment, improved equipment clearances, additional ties between Murray T.S and Kalar T.S. and the reduction of load on Municipal Substation #22 with conversion of some laterals to the new supply.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2013-0017	Reference #	SR-9

I. General Information

Project Title	Station 8 MS Rebuild	*Project Number*	2013-0017
Year	2013	*Service Area*	Niagara Falls
Total Capital Cost	$191,113	*Category*	System Renewal

II. Project Description

Description

Replacement of the 13.8kV/8.32kV distribution station equipment supplying portions of Niagara Falls around the Robinson Street / Allendale Street area. This work includes a new protection equipment, ground grid, and oil containment. The existing 5000kVA power transformer will be re-utilized as part of the design based on the results of the asset condition assessment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment - End of Life Assets**

Project #	**2013-0021**	**Reference #**	**SR-21**

I. General Information

Project Title	**Beacon Inn/Jordan - Overhead to Underground Primary Conversion**	***Project Number***	**2013-0021**
Year	**2013**	***Service Area***	**Lincoln**
Total Capital Cost	**$259,593**	***Category***	**System Renewal**

II. Project Description

Description

The project scope involves the installation of approximately 250 meters of 2/0 underground primary cable within a duct structure placed by Cogeco during a 2011 reconstruction project. Also included, is the construction of 8-spans of 3 phase and 11-spans of 3 phase pole line, which allows NPEI to deal with an inaccessible overhead pole line on private property for which easement documentation is unavailable.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2013-1007 & 2007	Reference #	SR-30
I. General Information			
Project Title	System Sustainment / Minor Betterments	*Project Number*	2013-1007 & 2007
Year	2013	*Service Area*	All
Total Capital Cost	$670,727	*Category*	System Renewal

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2013-1010 & 2010	Reference #	SR-31
I. General Information			
Project Title	**Pole Replacement Program**	***Project Number***	**2013-1010 & 2010**
Year	**2013**	***Service Area***	**All**
Total Capital Cost	**$859,298**	***Category***	**System Renewal**

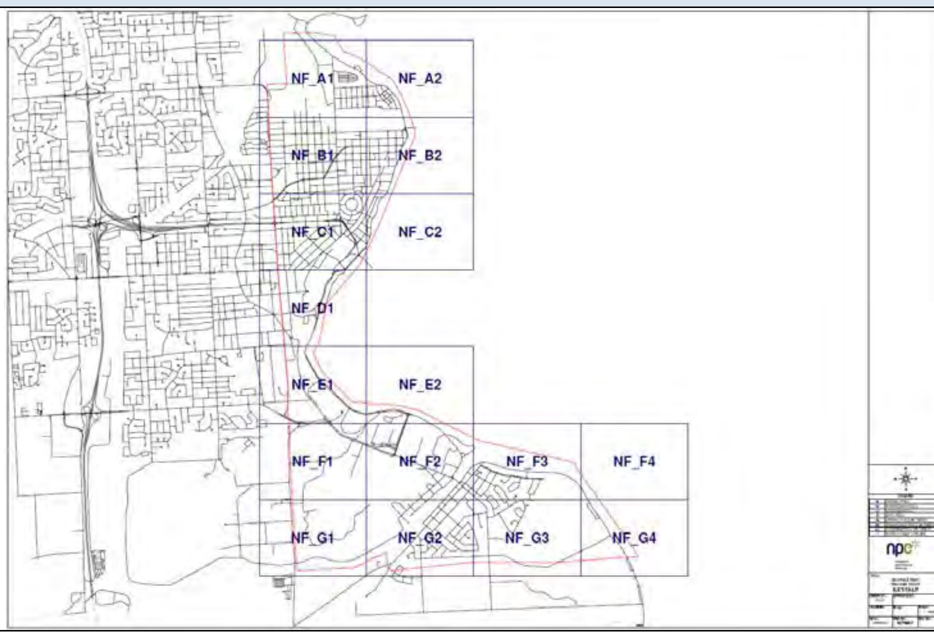
II. Project Description

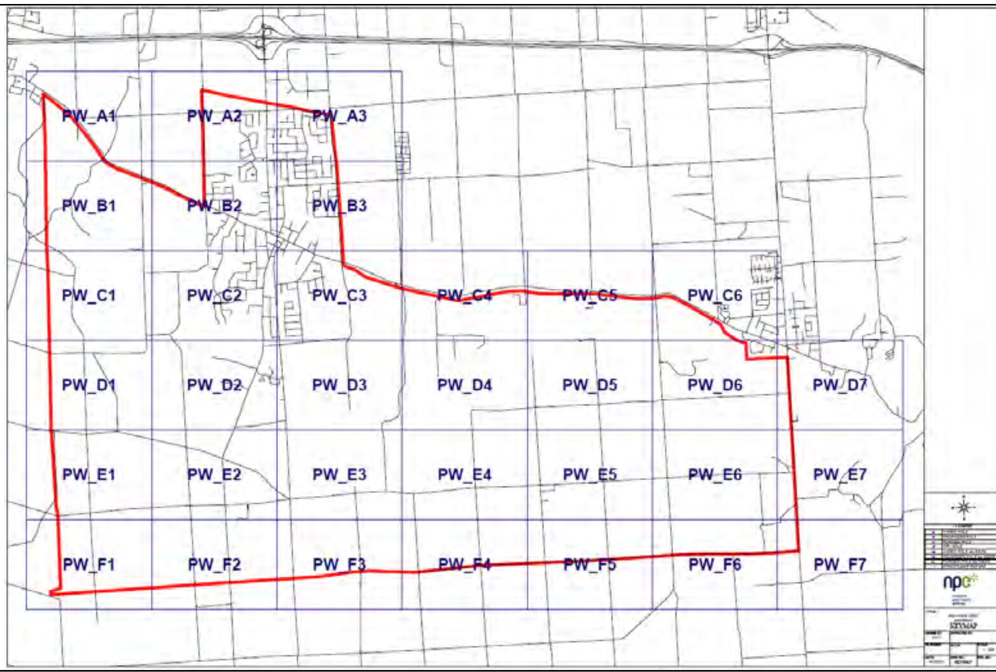
Description

Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The 2013 Niagara Falls test area is bounded in the West by Stanley Avenue, South to Chippawa Parkway/Weinbrenner Rd., East to the Niagara River, and North to Whirlpool Road. In the Western Service Territory the testing area is bounded by Reg Rd #24-Victoria Ave to the East, north to King Street including Beamsville, South to Young Street, and West to Thirty Road.

Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.

Map Overview





Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment / Poles at End of Life**

Project #	2013-0020	Reference #	SR-32

I. General Information

Project Title	**Kiosk/Submersible Replacement Program**	***Project Number***	**2013-0020**
Year	**2013**	***Service Area***	**All**
Total Capital Cost	**$643,270**	***Category***	**System Renewal**

II. Project Description

Description

The Kiosk replacement program is an integral part of our underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. The locations are prioritized by the results of a Conditional Assessment Survey completed in 2008, which will be repeated on a 5-year cycle as required.

65-Units remain on the 15KV system with 1 converted in 2012. 77-Units remain on the 5KV system with 12 converted in 2012. 3-units were also converted in the Fonthill area. 7-Submersible units were also converted to pad-mounts. For 2013 the plan is to replace 10 units.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2013-2011	Reference #	SR-33

I. General Information

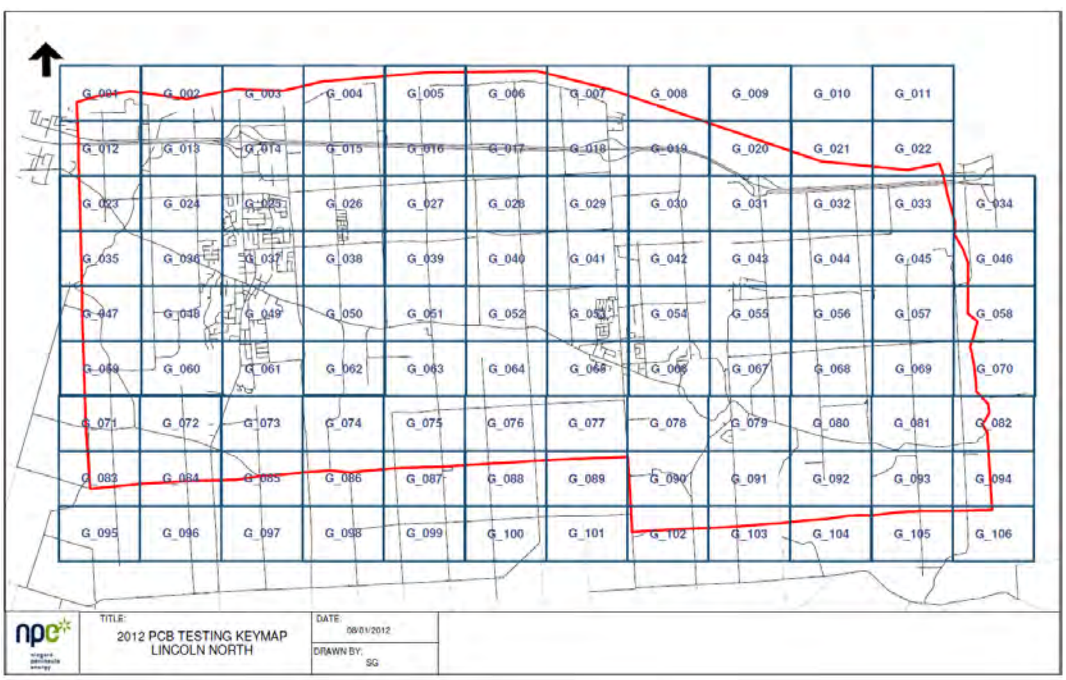
Project Title	**PCB Transformer Replacement Program**	***Project Number***	**2013-2011**
Year	**2013**	***Service Area***	**All**
Total Capital Cost	**$125,175**	***Category***	**System Renewal**

II. Project Description

Description

The first phase of the three year transformer testing program has been completed within the West service territory resulting in the requirement to replace 50 units identified as having over the legislated limit for PCB content. The program will track these change-outs which will likely include the replacement of the pole supporting the unit with associated transfers, removals and disposal costs. The second round of testing will begin in May of 2013. The 2012 test area is shown below.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Public and Worker Safety**

Project #	2013-0003	Reference #	SR-22

I. General Information

Project Title	Carry Over - Weightman Bridge Underground Primary Extension	*Project Number*	2013-0003
Year	2014	*Service Area*	Niagara Falls
Total Capital Cost	$701,810	*Category*	System Renewal

II. Project Description

Description

See 2013 Project Description

Map Overview

See 2013 Map Overview

Evaluation Criteria

See 2013 Evaluation Criteria

Drivers

See 2013 Drivers

Project #	2013-0005	Reference #	SR-1

I. General Information

Project Title	**Carry Over - 12M6 Conductor Replacement Simcoe, Buckly, Armoury St. Area**	*Project Number*	**2013-0005**
Year	**2014**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$372,631**	*Category*	**System Renewal**

II. Project Description

Description

See 2013 Project Description

Map Overview

See 2013 Map Overview

Evaluation Criteria

See 2013 Evaluation Criteria

Drivers

See 2013 Drivers

Project #	2013-0011	Reference #	SR-2

I. General Information

Project Title	Carry Over - Dorchester Rebuild - Garden to McMillan	*Project Number*	2013-0011
Year	2014	*Service Area*	Niagara Falls
Total Capital Cost	$362,018	*Category*	System Renewal

II. Project Description

Description

See 2013 Project Description

Map Overview

See 2013 Map Overview

Evaluation Criteria

See 2013 Evaluation Criteria

Drivers

See 2013 Drivers

Project #	2013-0017	Reference #	SR-9

I. General Information

Project Title	**Carry Over - Station 8 MS Rebuild**	***Project Number***	**2013-0017**
Year	**2014**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$252,037**	***Category***	**System Renewal**

II. Project Description

Description

See 2013 Project Description

Map Overview

See 2013 Map Overview

Evaluation Criteria

See 2013 Evaluation Criteria

Drivers

See 2013 Drivers

Project #	**2014-0001**	**Reference #**	**SR-24**

I. General Information

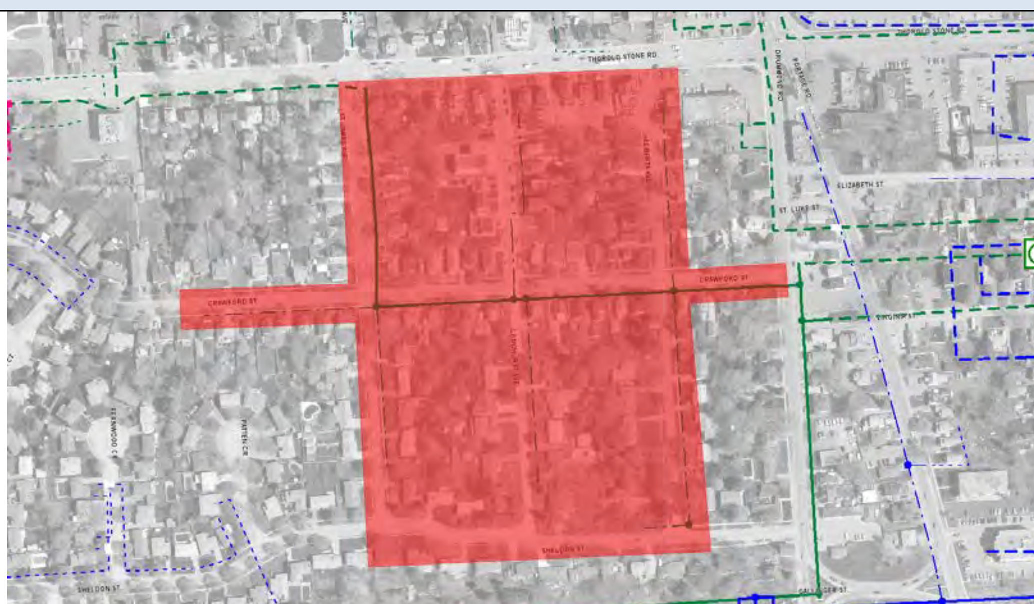
Project Title	**Crawford Street Rebuild - Thorold Stone to Sheldon**	***Project Number***	**2014-0001**
Year	**2014**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$516,557**	***Category***	**System Renewal**

II. Project Description

Description

This rebuild project targets 1.38 kilometers of urban distribution line installed in 1953. The scope includes 50 pole changes, new single (880 meters) and three phase (500 meters) primary and secondary (1790 meters) circuits. The scope also includes 10 distribution transformer replacements resulting in the upgraded supply to about 122 residential customers in the area bounded by Drummond Rd., Portage Road, Sheldon St., St James St., Longhurst Ave, Elberta ave. and Crawford St. System benefits include replacement of aging equipment, future voltage conversions opportunities, and improved equipment clearance.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2014-0004	Reference #	SR-25

I. General Information

Project Title	**Fallsview Blvd. Rebuild - Ferry to Robinson**	***Project Number***	**2014-0004**
Year	**2014**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$332,173**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves replacement of 0.5 kilometers of existing overhead 5kV line (F72) with an underground 15kV single circuit 3-phase line (3M54) between Robinson St and Ferry St pending a City of Niagara Falls Road Reconstruction Project. The Road reconstruction includes widening to 4-lanes and re-alignment of the intersection at Ferry St reducing the available boulevard required for construction of a pole line. The source will be a spare position in existing switching station #33 to a pole line north of Ferry Street. System benefits include replacement of aging equipment, conversion of an underground transformer vault at the Fairway Inn, and load reduction on the Municipal Substation #7 by conversion of the lateral to 15KV.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life** • **Loss Reduction**

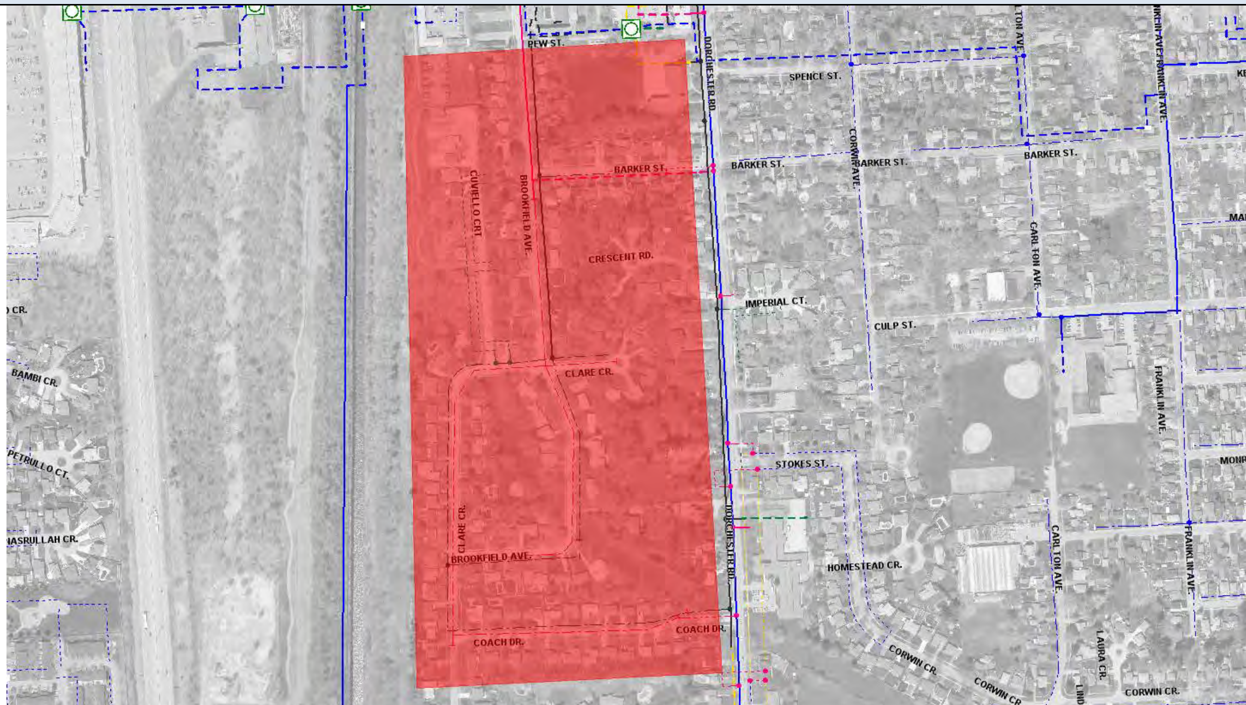
Project #	2014-0007	Reference #	SR-29
I. General Information			
Project Title	Station 22 South Rebuild - Bounded by Dorchester / Coach / Clare / Pew	*Project Number*	2014-0007
Year	2014	*Service Area*	Niagara Falls
Total Capital Cost	$516,513	*Category*	System Renewal

II. Project Description

Description

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2014 this program targets 1.7 kilometers of urban distribution line installed in 1960, including 58 pole changes, new single phase primary and secondary circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 125 residential customers in the area bounded by Dorchester Rd., Lundy's Lane, Coach Drive, Clare Crescent, Brookfield Avenue & Barker Street.

This multi-year project focuses on commencement of rebuild in the area surrounding Station 22.

Map Overview

Evaluation Criteria
Reliability/Performance: The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. New standards for single phase distribution incorporate covered primary conductor installed with an increase in the point of attachment. The covered conductor is capable of withstanding momentary tree contact without disruption of service. **Efficiency:** This area will be converted from 4.16kV to 13.8kV. Conversion of this area contributes to the elimination of two 4.16kV feeders. Both the feeder elimination and voltage conversion will contribute to a reduction in system losses. **Safety:** The project involves the replacement of poles at a substandard height. New construction includes the installation of 40' poles for the attachment of covered primary conductor. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.
Drivers
• **Sustainment** • **Replacement of Assets at End of Life**

Project #	2014-0008	Reference #	SR-28

I. General Information

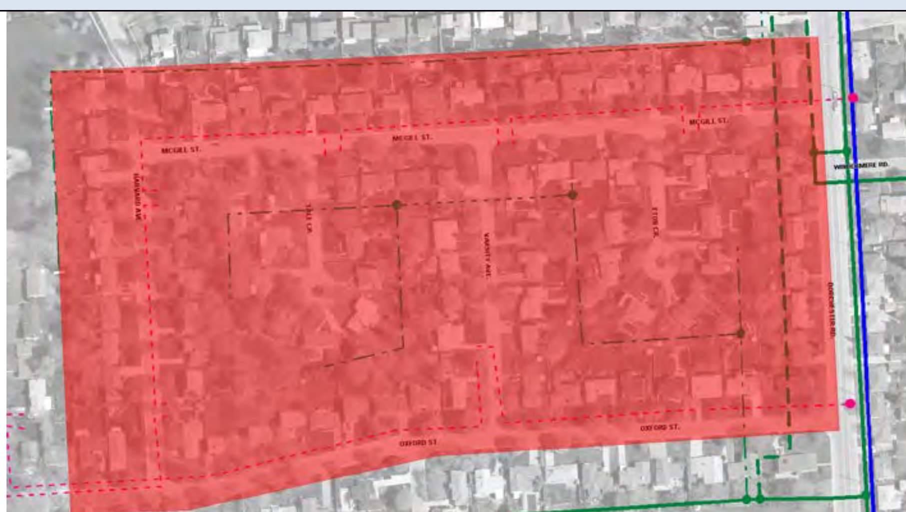
Project Title	**Rolling Acres OH to UG Conversion - Phase 1**	*Project Number*	**2014-0008**
Year	**2014**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$768,894**	*Category*	**System Renewal**

II. Project Description

Description

Phase I project scope involves the relocation of primary facilities currently situated on an inaccessible rear lot pole line within private property Easement documentation is available for this line. Directional boring will be used to install 2.1km of primary duct to 7 pad-mounted transformers placed on precast pads within the road allowance. Secondary laterals will be directionally bored back to the rear lot easements in order to source the 106 individual house services currently fed underground from existing junction boxes mounted on the poles. The streets included within this Phase include Oxford, Wiltshire, Valour, Yale, Harvard, Varsity, McGill, & Eton. The current equipment was installed in 1959 and tree growth, pool, shed and fencing installations, have made the line difficult to maintain and service. 15KV rated equipment will be installed for future voltage conversion, once all the phases have been completed.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2014-0009	Reference #	SR-23

I. General Information

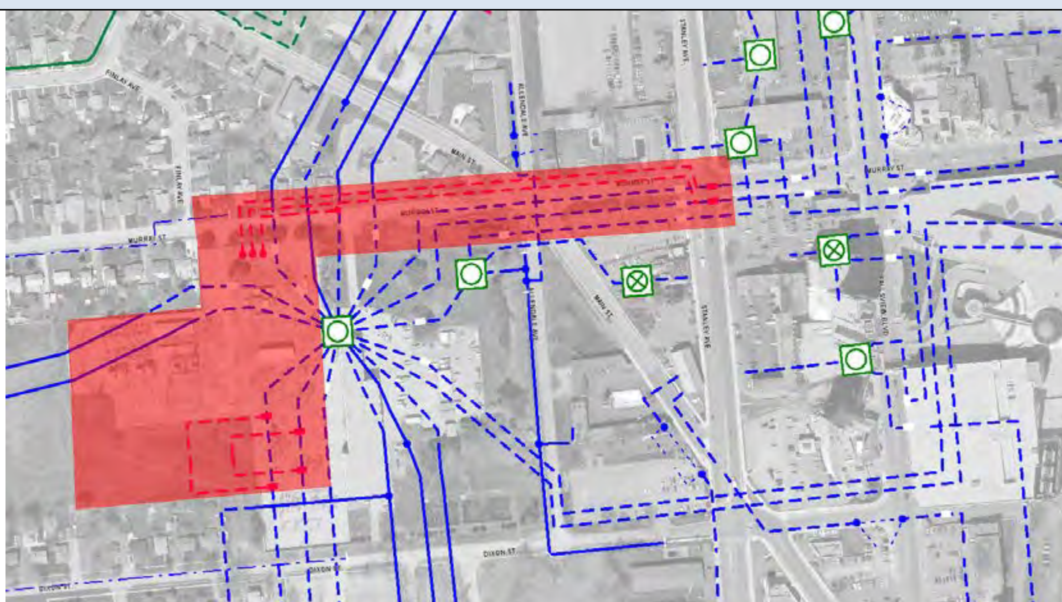
Project Title	3M28, 29, 30 Feeder Egress Replacement	*Project Number*	2014-0009
Year	2014	*Service Area*	Niagara Falls
Total Capital Cost	$417,731	*Category*	System Renewal

II. Project Description

Description

The project scope involves the installation of 3-new manhole assemblies within the Municipal R.O.W. outside of Murray Transformer Station, including the replacement of existing directly buried feeder conductors within existing duct structures installed previously. New primary underground cable will be installed from the feeder breakers consisting of approximately 3.0 kilometers of 600 kcMIL conductor and terminations at 3 new proposed metering units. Benefits include provisions for resolution of the expired wholesale metering points on feeders (metering is under a separate project) and improved supply reliability to the tourist core with the introduction of new supply cables.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Primary Cable at End of Life**

Project #	2014-0015	Reference #	SR-26

I. General Information

Project Title	Jordan Road Rebuild from Red Maple to the QEW	*Project Number*	2014-0015
Year	2014	*Service Area*	Lincoln
Total Capital Cost	$397,516	*Category*	System Renewal

II. Project Description

Description

The project scope involves the rebuild of existing 3-phase 8.32kV primary line, in place, constructed to 27.6KV standards for approx 2.0km. This includes the installation of 34-new 45' poles, transfer of existing primary conductors, and installation of 2.0km of new neutral. The project is driven by the pole inspection program which has identified a large number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and provisions for future conversion to 27.6KV of the feeders supplied by Jordan D.S. for its eventual de-commissioning.

Map Overview

Evaluation Criteria
N/A
Drivers
Sustainment   **Replacement of Assets at End Of Life**

Project #	2014-1006	Reference #	SR-27

I. General Information

Project Title	**Murray Y Bus Wholesale Meter Replacement**	*Project Number*	**2014-1006**
Year	**2014**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$300,000**	*Category*	**System Renewal**

II. Project Description

Description

Murray Y Bus metering is at end of life and no longer meets IESO standards for wholesale settlement. Project scope includes installation, connection and commissioning of 5 pad-mounted 15kV - 600A metering units. Scheduling of construction will be coordinated with project 2014-0009.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Regulatory Requirements**

Project #	2014-1007 & 2007	Reference #	SR-30
I. General Information			
Project Title	System Sustainment / Minor Betterments	*Project Number*	2014-1007 & 2007
Year	2014	*Service Area*	All
Total Capital Cost	$400,000	*Category*	System Renewal

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2014-1010 & 2010	Reference #	SR-31

I. General Information

Project Title	Pole Replacement Program	*Project Number*	2014-1010 & 2010
Year	2014	*Service Area*	All
Total Capital Cost	$778,702	*Category*	System Renewal

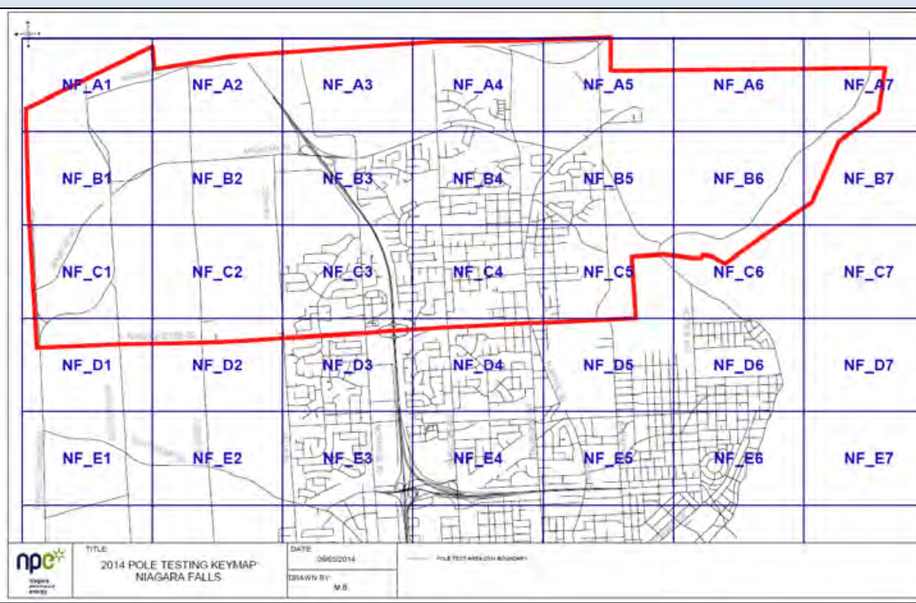
II. Project Description

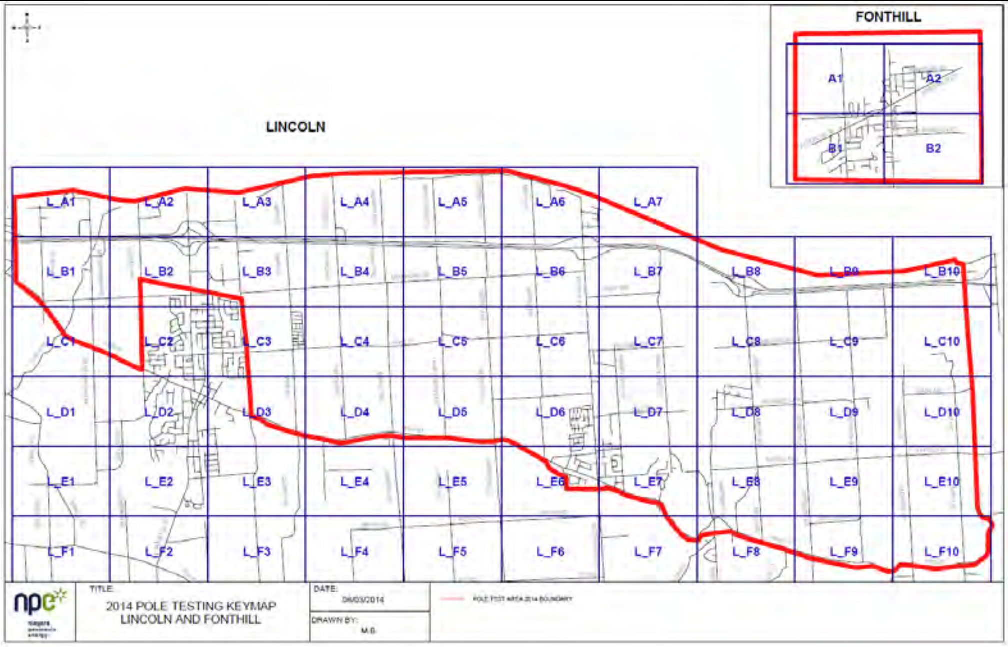
Description

Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The 2014 Niagara test area is bounded in the South by Thorold Stone Road, West to Thorold Town Line, North to Mountain Road, and East to Stanley Ave/Whirlpool Road. The Westerns service territory testing area is bounded by Lake Ontario to the North, south to King Street excluding Beamsville, East to Ninth Street, and West to Thirty Road.

Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.

Map Overview




Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment / Poles at End of Life**

Project #	2014-0020	Reference #	SR-32

I. General Information

Project Title	**Kiosk/Submersible Replacement Program**	*Project Number*	**2014-0020**
Year	**2014**	*Service Area*	**All**
Total Capital Cost	**$624,457**	*Category*	**System Renewal**

II. Project Description

Description

The Kiosk replacement program is an integral part of our underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. The locations are prioritized by the results of a Conditional Assessment Survey completed in 2013, which will be repeated on a 5-year cycle as required.

57-Units remain on the 15kV System with 8 were converted in 2013. 74-Units remain on the 5kV System with 4 were converted in 2013. 5-Submersible units were also converted to pad-mounts with only 4 remaining on the system. For 2014 the plan is to replace 10 units.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2014-2011	Reference #	SR-33

I. General Information

Project Title	**PCB Transformer Replacement Program**	***Project Number***	**2014-2011**
Year	**2014**	***Service Area***	**All**
Total Capital Cost	**$566,479**	***Category***	**System Renewal**

II. Project Description

Description

The second phase of the three year transformer testing program has been completed within the West service territory resulting in the requirement to replace units identified as having over the legislated limit for PCB content. The program will track these change-outs which will likely include the replacement of the pole supporting the unit with associated transfers, removals and disposal costs. The final round of testing will begin in May of 2014. The 2013 test area is shown below.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Public and Worker Safety**

System Service

Project #	2010-0001	Reference #	SS-54
I. General Information			
Project Title	**Robinson St. Allendale to Clark UG Primary Extension**	***Project Number***	**2010-0001**
Year	**2010**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$306,868**	***Category***	**System Service**
II. Project Description			
Description			
Due to increasing load growth and proposed development within the Fallsview Tourist/Commercial Core the introduction of an additional feeder into the area is required. The proposal would include the construction of a 600 meter long duct bank for extension of a 600 Amp 13,800 Volt distribution feeder using the Murray Station 3M54 from the existing double circuit pole line in the adjacent Hydro One Corridor. The 3M54 circuit will be directed into the manhole/switchgear assembly at Station #33 on Fallsview Blvd. The circuit will continue to a new manhole/switchgear assembly on Clarke Ave. This will also include replacement of the high voltage switchgear #48 at Old Stone Inn and modifications to the Budget Inn Stn. #120. Both switchgear units are nearing end of life based on asset condition assessment data. The Construction will provide load relief & alternate buss supply to loads currently supplied by the 3M29 Feeder.			
Map Overview			

Evaluation Criteria

Reliability/Performance:

The current supply into this area is at capacity during summer peak loads. The additional circuit will offload existing circuits resulting in additional capacity for this area which primarily consists of commercial load. The additional circuit will also provide an alternate backup supply to the existing 2 circuits should a component failure occur.

Efficiency:

Elimination of legacy switchgear and transformation will reduce the requirement for stock replacements. Estimated restoration time from on outage due to component failure in the area is expected to decrease as a result of the additional back-feed.

Safety:

The project involves eliminating 2 air insulated switchgears which are at end of life and present enclosure integrity issues. New switchgear that is installed as part of the scope of this project adhere to NPEI's latest equipment specifications and incorporate a dead front design.

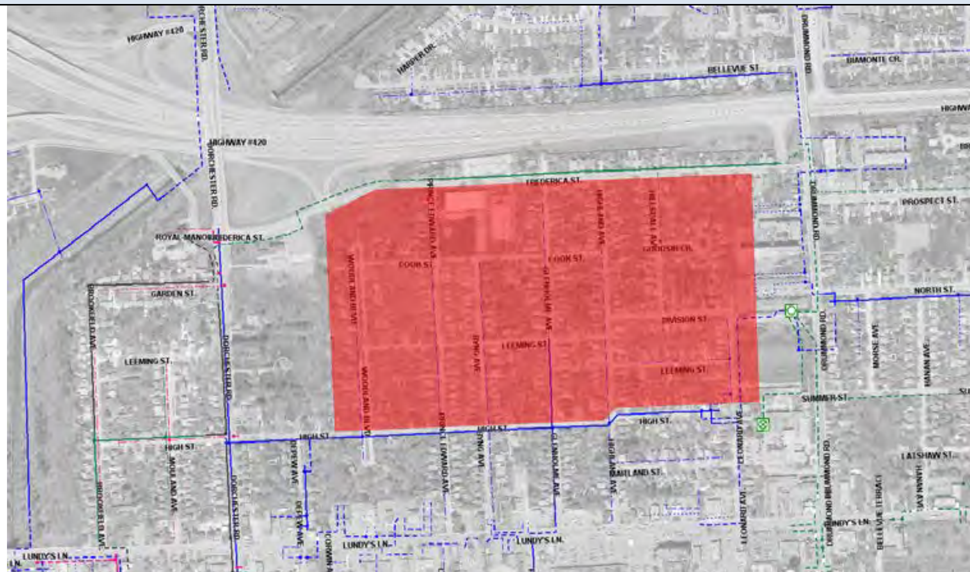
Community Relations:

Removal of large transformers and switchgear with enclosure deterioration improves overall aesthetics of NPEI plant present in the area.

Drivers

- **Reliability**
- **Capacity**
- **Power Quality**
- **Safety**
- **Efficiency**

Project #	2010-0002	Reference #	SS-37
I. General Information			
Project Title	**High Street Area Rebuild**	***Project Number***	**2010-0002**
Year	**2010**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$255,782**	***Category***	**System Service**
II. Project Description			
Description			
This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. This project focuses on completion of rebuild in the High Street area. This is a multi-year project that commenced in 2008.			

Map Overview

Evaluation Criteria
Reliability/Performance: The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. New standards for single phase distribution incorporate covered primary conductor installed with an increase in the point of attachment. The covered conductor is capable of withstanding momentary tree contact without disruption of service. **Efficiency:** This area is being prepared for conversion from 4.16kV to 13.8kV at a later date. Conversion of this area contributes to the eventual elimination of Station 22 which is approaching end of life. Both the station elimination and voltage conversion will contribute to a reduction in system losses. **Safety:** The project involves the replacement of poles at a substandard height. New construction includes the installation of 40' poles for the attachment of covered primary conductor. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.
Drivers
• **Reliability** • **Capacity** • **Power Quality** • **Safety** • **Efficiency**

Project #	2010-0006	Reference #	SS-34

I. General Information

Project Title	**Switchgear Replacement Program**	***Project Number***	**2010-0006**
Year	**2010**	***Service Area***	**All**
Total Capital Cost	**$461,327**	***Category***	**System Service**

II. Project Description

Description

Results from the underground equipment inspection program in 2008 and 2009 identified 17 switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.
Efficiency:
Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.
Safety:
The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.
Community Relations:
Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics

of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.
Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2010-0007	Reference #	SS-62
I. General Information			
Project Title	Murray Street Area Rebuild - Culp St. from Main to Drummond	*Project Number*	2010-0007
Year	2010	*Service Area*	Niagara Falls
Total Capital Cost	$211,701	*Category*	System Service

II. Project Description

Description

This project involves the installation of a 13.8kV 3-phase circuit in place of the existing single phase circuit in preparation for voltage conversion in the surrounding area of Culp St. The new 3-phase circuit will consist of tree cable installed on fiber glass brackets in order to minimize the effects of tree contact in the area. The new line will also present a 13.8kV source into Main Street to facilitate conversion of municipal station #8 loads in the future.

Map Overview

Evaluation Criteria
Reliability/Performance: The replacement of facilities with construction utilizing fiberglass components and covered cable (tree cable) will improve reliability in the area. Both technologies minimize the impact of foreign interface and tree contact. The covered conductor is capable of withstanding momentary tree contact without disruption of service. **Efficiency:** Installation of this 3 phase circuit prepares the surrounding area for conversion from 4.16kV to 13.8kV which will result in a reduction of overall system losses. **Safety:** New construction includes the installation of 45' poles for the attachment of covered primary conductor on insulated brackets. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.
Drivers
• **Reliability** • **Capacity** • **Power Quality** • **Safety** • **Efficiency**

Project #	2010-0008	Reference #	SS-47

I. General Information

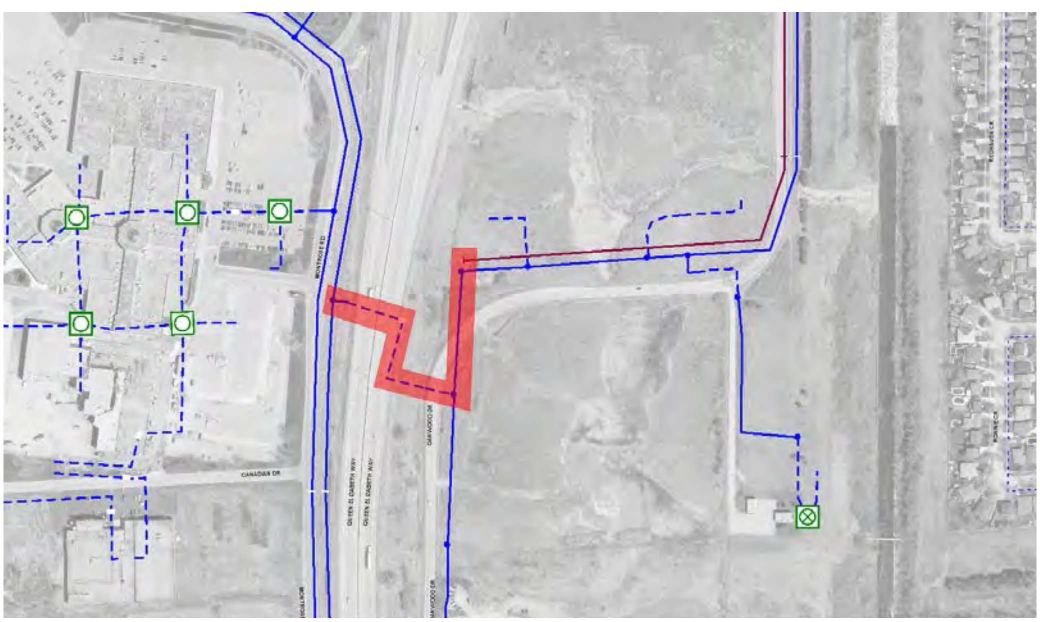
Project Title	Oakwood Drive - Line Relocate	*Project Number*	2010-0008
Year	2010	*Service Area*	Niagara Falls
Total Capital Cost	$198,387	*Category*	System Service

II. Project Description

Description

Scope of work involves connection of the exiting highway crossing opposite Niagara Square to the new double circuit line on Oakwood Drive. The project will also incorporate the relocation of a section of off-road line, south of the construction limits to the boulevard, to improve access & facilitate road lighting. Construction is required due to construction conflicts with the Smart Center road works, and system requirements for additional circuit intertie capabilities between Kalar M.T.S. and Murray T.S. The circuit interties improve feeder load balancing during contingencies.

Map Overview



Evaluation Criteria
Reliability/Performance: Extension of the KM2, KM6 circuits provides intertie capability between Murray TS and Kalar TS. The additional circuits provide a back up supply and **r**edundancy for surrounding customers in the area. This reduces overall circuit exposure on connected circuits. **Efficiency:** Relocation of the off-road circuit to the road allowance improves response and restoration times in the event of a component failure. **Safety:** Existing poles on Oakwood Dr. are nearing end of life. These will be eliminated as a result of this project and replaced with a higher class, increased height pole. This will increase public and worker safety in the area. **Community Relations:** Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant present in the area.
Drivers
• **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2010-0023	Reference #	SS-36
I. General Information			
Project Title	Durham Voltage Conversion	*Project Number*	2010-0023
Year	2010	*Service Area*	Lincoln
Total Capital Cost	$364,430	*Category*	System Service

II. Project Description

Description

The final phase of this voltage conversion project will focus on the customers supplied on the periphery of the area supplied by the Durham 27.6 / 8.32 kV station. This facilitates a staged reduction for elimination of load supplied by this station. The station was constructed on a temporary basis years ago to deal with increasing loads and was not constructed in a manner that would provide for a long-term reliable source of power. By rebuilding and converting 8.32 kV customer loads along Durham Road, Greenlane Road and Mountainview Road, a reduction in loading will be realized on the station and additional 27.6 kV ties will be available to provide increased reliability in this area. This phase will achieve a complete load conversion and elimination of the station.

Map Overview

Evaluation Criteria
Reliability/Performance: The Durham DS transformer is at end of life. It's removal eliminates the impact of transformer failure on reliability. Addition of a 27.6kV intertie between Beamsville TS 18M1 and 18M4 provides increased redundancy for connected loads in the area. **Efficiency:** Loss reduction will result from elimination of the power transformer at Durham DS and voltage conversion to 27.6kV. **Safety:** The exiting Durham DS power transformer is situated on a temporary structure that was never intended for long term utilization. Public and worker safety is improved through elimination of this hazard. **Community Relations:** Removal of the deteriorated apparatus and the elimination of Durham DS along with construction of an improved appearance circuit along Greenlane Rd. benefit the aesthetics of plant in the area.
Drivers
• **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2010-0024	Reference #	SS-35
I. General Information			
Project Title	**Cherry Avenue Voltage Conversion**	***Project Number***	**2010-0024**
Year	**2010**	***Service Area***	**Lincoln**
Total Capital Cost	**$179,386**	***Category***	**System Service**
II. Project Description			
Description			
The project scope is extension of .75 km 3-Phase 8.32 kV supply from Yonge Street, on Cherry Avenue. This is to eliminate a deteriorated, inaccessible, overhead 8.32 kV circuit through the Twenty Valley Golf Course property. Many poles are identified for immediate replacement through the asset condition assessment. Equipment will be installed within the Road Allowance and secondary will be installed to supply the existing pump equipment. Upon completion, the line will be removed through the golf course.			
Map Overview			

Evaluation Criteria
Reliability/Performance: Access to the existing, off-road primary distribution line is suspect and negatively impacts the golf course. Relocation of the line to the road allowance provides NPEI direct access for inspection, maintenance and tree clearing purposes. **Efficiency:** Improved accessibility will reduce response and restoration durations in the event of an outage. **Safety:** The majority of the existing poles slated for replacement are at end of life based on asset condition assessment. Removal of these facilities eliminates hazard associated with structural failure in a space frequently accessed by the public. **Community Relations:** Removal of the deteriorated apparatus to the road allowance eliminates the negative impacts caused by NPEI plant on the appearance of the golf course and surrounding area.
Drivers
• **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2010-Smart Meters	Reference #	

I. General Information

Project Title	**Smart Meters**	***Project Number***	**2010-0001**
Year	**2010**	***Service Area***	**All**
Total Capital Cost	**$4,175,010**	***Category***	**System Service**

II. Project Description

Description

Expenditures related to the Provincial mandate for installation of Smart Meters.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Regulatory Compliance**

Project #	2010-0001	Reference #	SS-54

I. General Information

Project Title	**Carry Over - Robinson St. Allendale to Clark UG Primary Extension**	*Project Number*	**2010-0001**
Year	**2011**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$733,072**	*Category*	**System Service**

II. Project Description

Description

See 2010 Project Description

Map Overview

See 2010 Map Overview

Evaluation Criteria

See 2010 Evaluation Criteria

Drivers

See 2010 Drivers

Project #	2011-0003	Reference #	SR-50

I. General Information

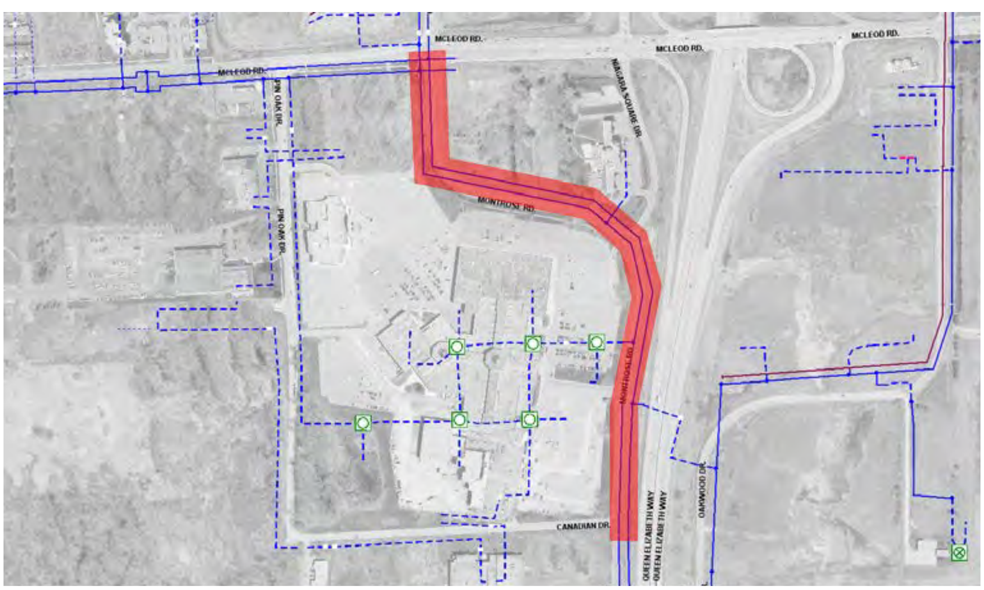
Project Title	**KM2 - KM6 Extension Montrose Rd., McLeod to Canadian Drive**	***Project Number***	**2011-0003**
Year	**2011**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$347,760**	***Category***	**System Service**

II. Project Description

Description

Extension of a double circuit overhead line is required in the area due to increasing residential load growth and proposed Smart Centre Developments. The area is currently serviced by the 3M30 circuit and there is limited redundant supply in the area. The scope involves extension of the double circuit overhead line using Kalar M.T.S. feeders KM2 and KM6, from the existing dead-end at McLeod Road. The circuits will project south on Montrose Rd. to the existing highway crossing opposite Niagara Square. Construction is in conjunction with the relocation of the pole line on Oakwood Drive, due to road works for the Smart Centre currently under construction. Benefits include additional circuit inter-tie capabilities between Kalar & Murray Transformer Stations circuits for feeder load balancing and contingency options.

Map Overview



Evaluation Criteria
Reliability/Performance: Extension of the KM2, KM6 circuits provides intertie capability between Murray TS and Kalar TS. The additional circuits provide a back up supply and redundancy for surrounding customers in the area. This reduces overall circuit exposure on connected circuits. **Efficiency:** Loss reduction will result from re-directing commercial loads in the area to Kalar TS circuits as the normal source of supply. The length of line to the load center will significantly less when supplied from Kalar TS. **Safety:** Existing poles on Montrose Rd. are nearing end of life. These will be eliminated as a result of this project and replaced with a higher class, concrete pole. This will increase public and worker safety in the area. **Community Relations:** Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant present in the area.
Drivers
• **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2011-0006	Reference #	SS-34

I. General Information

Project Title	Switchgear Replacement Program	*Project Number*	2011-0006
Year	2011	*Service Area*	All
Total Capital Cost	$191,370	*Category*	System Service

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:
Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:
The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:
Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2011-0008	Reference #	SS-48

I. General Information

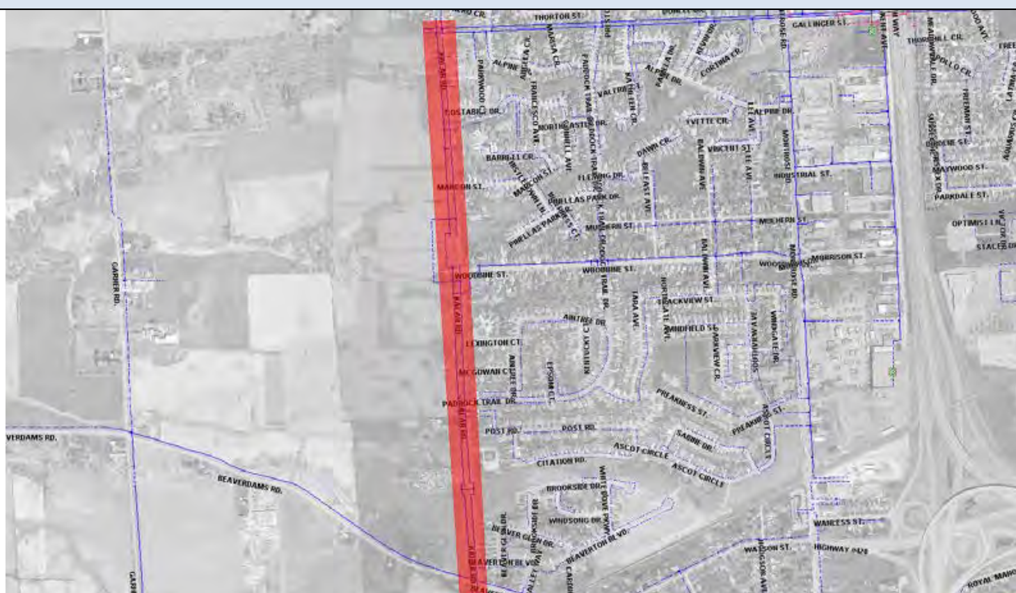
Project Title	Kalar Rebuild - N.S. & T. ROW to Beverdams	*Project Number*	2011-0008
Year	2011	*Service Area*	Niagara Falls
Total Capital Cost	$385,308	*Category*	System Service

II. Project Description

Description

The rebuild of 1600 meters of existing KM3 15 kV single circuit 3-phase pole line between Beaverdam's Rd. and the NS&T R.O.W with a double circuit concrete pole line. The pole line will be built on the West side of Kalar Road using the KM3 and KM7 feeders sourced from Kalar M.T.S. Construction is required in conjunction with circuit extensions completed for CNF road widening works between Lundy's Lane and Beaverdam's Rd. Construction is also required due to the age of existing plant, clearance issues, and requirement of an additional circuit for intertie capabilities to Stanley T.S. circuits 12M32 and 12M42 for feeder load balancing and contingency purposes.

Map Overview



Evaluation Criteria
Reliability/Performance: Extension of Kalar TS circuits will provide additional intertie capability with Stanley TS providing additional backfeed capability during contingencies. **Efficiency:** Additional circuit tie's will reduce response and restoration times in outage scenarios. The single circuit is 15kV circuit is being upgraded to 556 kcMIL conductor which will reduce system losses. **Safety:** New construction includes the installation of 50' poles with increased point of attachment to current standards. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency**

Project #	Mobile Substation	Reference #	

I. General Information

Project Title	**Mobile Substation**	*Project Number*	**N/A**
Year	**2011**	*Service Area*	**All**
Total Capital Cost	**$214,555**	*Category*	**System Service**

II. Project Description

Description

Design, material procurement and construction of a 27.6kV - 8.32kV mobile substation. All of the distribution substations in the Lincoln / West Lincoln portion of NPEI's service territory are islanded and to not tie to other sources. These include:

Campden DS
Greenlane DS
Smithville DS
Jordan DS

The substation will consist of a 4MVA power transformer, high side dead-front switchgear, low side dead-front switch gear (2 feeders) all installed on a float deck trailer. The unit will be capable of being placed within the station confines of these 4 DS locations. The purpose is to reduce restoration time in a contingency from days to 2 hours.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
The mobile substation will provide a timely solution to achieve restoration in the event of component failure at one of the distribution stations in Lincoln or West Lincoln
Efficiency:
The former Pen West utilities (serving the Lincoln and West Lincoln areas) previously experienced significant outages at these DS locations due to equipment failure. In some cases, the restoration time was a matter of days. Availability of the mobile substation will permit NPEI to restore service to connected customers in a matter of hours.

Safety: The design of the mobile substation incorporates dead-front switch gear to maximize worker safety. Cables egressing from the unit will be fully shielded and provisions will be provided to achieve 2 points of connection to station ground grids. **Community Relations:** Significant mitigation of restoration times provides a direct benefit to communities during outage events at a DS in these ares.
Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2012-0003	Reference #	SS-51

I. General Information

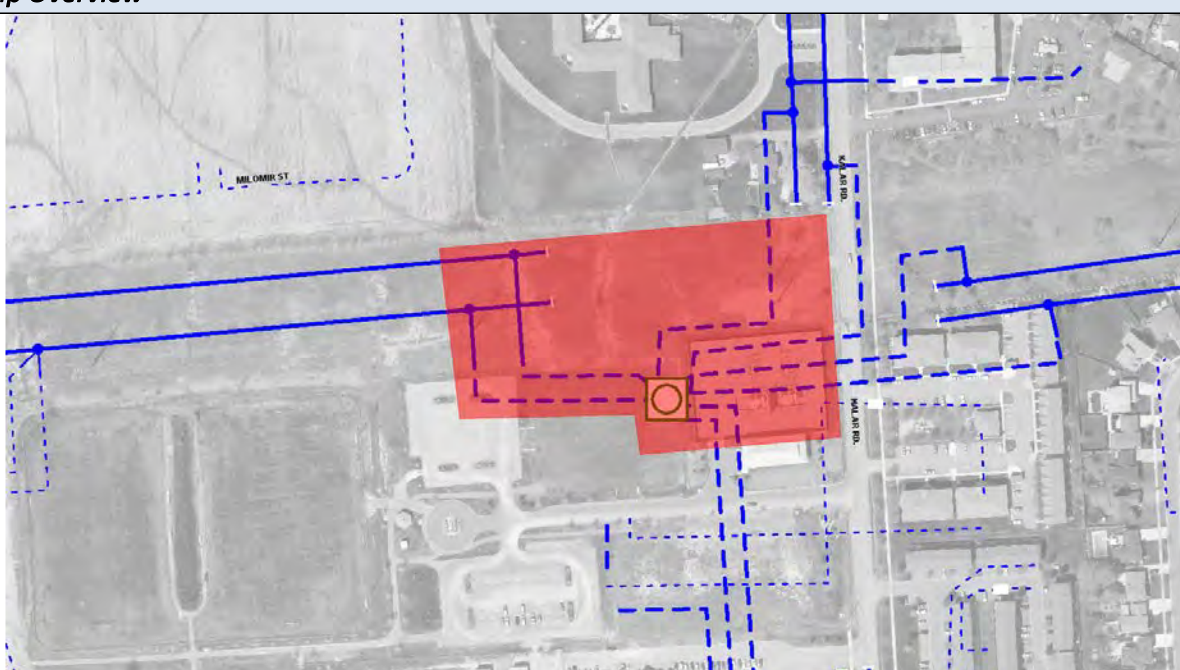
Project Title	**Kalar MTS - KM1 and KM5 Feeder Egress**	***Project Number***	**2012-0003**
Year	**2012**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$169,041**	***Category***	**System Service**

II. Project Description

Description

This project is due to residential load growth and proposed developments within the area currently serviced by the Kalar KM7 and KM2 feeders. The project scope involves the construction of an 150M underground duct bank from the existing double circuit overhead line within the Hydro One transmission corridor to the 2-existing spare breaker positions at the Kalar M.T.S. building. Benefits include additional circuit inter-tie capabilities between feeders egressing from Kalar & Murray Transformer Stations for feeder load relief, balancing, and contingency purposes.

Map Overview



Evaluation Criteria
Reliability/Performance: Reduction of exposure on the existing KM2 and KM7 circuits minimizes the affected customers during feeder outages. **Efficiency:** Additional intertie capability from Kalar TS will provide back-up supply during contingencies and station maintenance activities. **Safety:** Cables will egress in existing civil structures on station property (previously installed) minimizing disruption to the adjacent school and soccer complex. **Community Relations:** Introduction of the KM1 and KM5 circuits reduces rural exposure to commercial loads supplied from the KM2 and KM7 circuits. The sensitive loads on these existing circuit will see a experience a reduction in outage events.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency**

Project #	2012-0006	Reference #	SS-34

I. General Information

Project Title	Switchgear Replacement Program	*Project Number*	2012-0006
Year	2012	*Service Area*	All
Total Capital Cost	$313,737	*Category*	System Service

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:

All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:

Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:

The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:

Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2012-0008	Reference #	SS-48

I. General Information

Project Title	**Carry Over Kalar Rebuild - N.S. & T. ROW to Beverdams**	*Project Number*	**2012-0008**
Year	**2012**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$383,130**	*Category*	**System Service**

II. Project Description

Description

See Project Description for 2011-0008.

Map Overview

See 2011 Map Overview

Evaluation Criteria

See 2011 Evaluation Criteria

Drivers

See 2011 Drivers

Project #	2012-SG	Reference #	

I. General Information

Project Title	Grid Modernization Program	*Project Number*	2012-SG
Year	2012	*Service Area*	All
Total Capital Cost	$332,339	*Category*	System Service

II. Project Description

Description

This is the first phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX capable devices (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.
Efficiency:
Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.

Safety:
With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides visibility of station and system status at all times.
Community Relations / Regulatory:
Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.

Drivers

- **Reliability**
- **Safety**
- **Efficiency**
- **Regulatory**

Project #	2013-0006	Reference #	SS-34

I. General Information

Project Title	Switchgear Replacement Program	*Project Number*	2013-0006
Year	2013	*Service Area*	All
Total Capital Cost	$264,913	*Category*	System Service

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:

All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:

Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:

The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:

Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2013-SG	Reference #	

I. General Information

Project Title	**Grid Modernization Program**	*Project Number*	**2013-SG**
Year	**2013**	*Service Area*	**All**
Total Capital Cost	**$348,370**	*Category*	**System Service**

II. Project Description

Description

This is the second phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX cable devies (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:

Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.

Efficiency:

Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.

Safety:
With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides visibility of station and system status at all times.
Community Relations / Regulatory:
Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.

Drivers

- **Reliability**
- **Safety**
- **Efficiency**
- **Regulatory**

Project #	2014-0006	Reference #	SS-34

I. General Information

Project Title	**Switchgear Replacement Program**	***Project Number***	**2014-0006**
Year	**2014**	***Service Area***	**All**
Total Capital Cost	**$110,057**	***Category***	**System Service**

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:
Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:
The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:
Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2014-0018	Reference #	SS-53
I. General Information			
Project Title	King Street - 27.6kV Extension to Martin Road	*Project Number*	2014-0018
Year	2014	*Service Area*	Lincoln
Total Capital Cost	$112,554	*Category*	System Service
II. Project Description			

Description

The Project Scope involves the rebuild of existing 1-phase 16KV primary line west of Martin Ave to the 3-phase dead-end, in place, and constructed to 3-phase 27.6KV for approx 280 meters. Construction involves the installation of 8-new 45' poles, transfer of 1-primary riser, and installation of 165 m of new 3-phase from Rittenhouse Road to Martin Rd, and removal of 6-existing poles. Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

Map Overview

Evaluation Criteria
Reliability/Performance: Extension of the 27.6kV circuit on King St. provides a second back-up source to Vineland F1 loads east of Martin Road. **Efficiency:** The primary line extension provides a more direct route from source to loads east of this location which reduces distribution system losses on the Vineland F1 circuit. **Safety:** New construction includes the installation of 45' poles with increased point of attachment to current standards. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant.
Drivers
• **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	**2014-SG**	**Reference #**	

I. General Information

Project Title	**Grid Modernization Program**	***Project Number***	**2014-SG**
Year	**2014**	***Service Area***	**All**
Total Capital Cost	**$227,500**	***Category***	**System Service**

II. Project Description

Description

This is the third phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX capable devices (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.

Efficiency:
Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.

Safety: With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides visibility of station and system status at all times. **Community Relations / Regulatory:** Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.
Drivers
• **Reliability** • **Safety** • **Efficiency** • **Regulatory**

Project #	2014-Smart Meters	Reference #	
I. General Information			
Project Title	Smart Meters	*Project Number*	2014-Smart Meters
Year	2014	*Service Area*	All
Total Capital Cost	$1,903,089	*Category*	System Service
II. Project Description			
Description			
Expenditures related to the Provincial mandate for installation of Smart Meters.			
Map Overview			
N/A			
Evaluation Criteria			
N/A			
Drivers			
• **Regulatory Compliance**			

General Plant

Project #	2010-General Plant	Reference #	
I. General Information			
Project Title	**General Plant**	***Project Number***	**N/A**
Year	**2010**	***Service Area***	**All**
Total Capital Cost	**$1,621,018**	***Category***	**General Plant**
II. Project Description			

Description

The following table is a summary of General Plant capital expenditures in 2010:

General Plant	Expenditure
Building	$67,188
Computer Hardware	$257,960
Computer Software	$250,022
Vehicles	$869,037
General Equipment	$176,811

2010 Expenditures Include:

Building:

- The final costs of the new Service Centre in Smithville, which was substantially completed in 2009. 23K.
- A new roof on NPEI's Niagara Falls building. $22K.

Computer Hardware:

- Installation of mobile workstations in fleet vehicles. This provides NPEI's operations staff working in the field real-time access to many of NPEI's systems. 106K.
- New and replacement servers. $99K.

Computer Software:

- Workforce/Outage Management – This software provides for recording and reporting of all work force tasks, as well as, details of an outage. It allows for the efficiency and reliability of reporting to regulatory agencies, as well as, efficiencies in management of resources required to complete tasks and oversee an outage. This solution accommodates our growth where current manual or

other software has become too labour intensive in the security, scalability; costly to manage (does not accommodate changes in technology.) Workforce/Outage management compliments pilot field projects/exercises where ruggedized laptops/PCs are in the field. This solution will contribute to the provision of effective and efficient processes improving customer service. $85K.
- Harris Northstar CIS. $83K.
- Phone system software. $22K.
- Microsoft Dynamics GP. $22K.

Vehicles:
- Ford 4x4 pick-up truck. $39K.
- 46’ Material Handling Aerial Manlift and fiberglass body. $195K.
- 47’ Radial Boom Derrick and fiberglass body. $205K.
- Off-road track vehicle. $426K.

General Equipment:
- Plotter. $20K.
- Cheque Encoder. $5K.
- Forklift and charger. $19K.
- Stores racking. $7K.
- Line hoses. $22K.
- Polyflex rope. $20K.
- Radios. $9K.
- Defibrillators. $5K.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Business Operations Efficiency**
- **Distribution System Operation Support**

Project #	2011-General Plant	Reference #	

I. General Information

Project Title	General Plant	*Project Number*	N/A
Year	2011	*Service Area*	All
Total Capital Cost	$1,279,896	*Category*	General Plant

II. Project Description

Description

The following table is a summary of General Plant capital expenditures in 2011:

General Plant	Expenditure
Building	$121,779
Computer Hardware	$247,812
Computer Software	$193,505
Vehicles	$541,643
General Equipment	$175,156

2011 Expenditures Include:

Building:
- New energy efficient lighting fixtures in the Niagara Falls garage area. $72K.
- A concrete pad and outdoor racking for wire storage in Smithville. $37K.

Computer Hardware:
- Installation of mobile workstations in fleet vehicles. 63K.
- New and replacement servers. $146K.

Computer Software:
- Workforce/Outage Management. $47K.
- Harris Northstar CIS. $92K.
- Phone system software. $10K.
- Apollo Workflow. $15K.

Vehicles:
- Ford F-150 pick-up truck. $30K.
- 46’ Material Handling Aerial Manlift and fiberglass body, with 2012 International 4400 chassis.

$267K.

- Freightliner Aerial Device and Chassis. $323K.
- 2 trailers (Gooseneck trailer for off-road track machine and 55’ pole trailer). $75K.

General Equipment:

- Photocopiers. $36K.
- Office furniture. $16K.
- Paging system. $8K.
- Stores equipment. $10K.
- Hoist upgrade. $19K.
- Tools for line trucks. $11K.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Business Operations Efficiency**
- **Distribution System Operation Support**

Project #	2012-General Plant	Reference #	

I. General Information

Project Title	General Plant	*Project Number*	N/A
Year	2012	*Service Area*	All
Total Capital Cost	$2,620,751	*Category*	General Plant

II. Project Description

Description

The following table is a summary of General Plant capital expenditures in 2012:

General Plant	Expenditure
Building	$631,111
Computer Hardware	$370,710
Computer Software	$213,431
Vehicles	$1,160,649
General Equipment	$244,851

2012 Expenditures Include:

Building:

- The steel pole bunks located in the Niagara Falls yard were installed in 1985. Due to weather and ground conditions these steel pole bunks have deteriorated and sunk into the ground and have become a hazard and pose a safety risk. In 2012, NPEI replaced these steel pole bunks with a precast concrete pole rack storage system. These new bunks are estimated to have a service life of 60 years. $131K.
- At the time, NPEI employed 31 management personnel. There were 25 offices combined between the two administration buildings. Desk space was being occupied at 100% capacity. Employees were working in the Quiet Room at the Niagara Falls facility. In 2012, NPEI completed a workspace optimization project in its Niagara Falls building to utilize the administration building's space more efficiently. This project resulted in the creation of 7 new offices and several new work stations in the old meter shop area. This area now houses NPEI's CDM, Human Resources, Corporate Communications and Purchasing departments. A new storage room for accounting records was also included in this project. 303K.
- Prior to 2012, NPEI's fleet vehicles in the Niagara Falls area were fueled from on-site tanks that were installed in 19XX. Vehicles in the Smithville area were fueled from local gas stations, using a corporate gas card. In 2012, NPEI replaced the fuel tanks in Niagara Falls and installed fuel tanks

in Smithville. The installations also include a tracking and control systems. 120K.

Computer Hardware:

- New and replacement servers. $242K.
- Network Switches. $23K.
- Access card system. $22K.
- Firewall. $22K.
- PCs, monitors and printers. $32K.

Computer Software:

- VM Ware $46K.
- Harris Northstar CIS. $67K.
- Apollo Workflow. $45K.
- Disaster Recovery software. $39K.

Vehicles:

- Ford F-150 pick-up truck. $34K.
- GMC Cargo Van. $33K.
- 50’ Terex RBD. $326K.
- 46’ Material Handling Aerial Manlift. $272K.
- 2 x 42’ Aerial Manlifts. $459K.
- 3 trailers (2 reel trailers and a 55’ pole trailer). $37K.

General Equipment:

- Office Furniture, mainly relating to the Workspace Optimization project. $91K.
- Photocopiers. $18K.
- Tools for line trucks. $46K.
- Arc Reflection system. $30K.
- Manhole excavation equipment. $13K.
- Portable Service Transformer. $10K.
- Skid Resistant Mats. $9K.
- Defibrillators. $8K.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Business Operations Efficiency**
- **Distribution System Operation Support**

Project #	2013-General Plant	Reference #	

I. General Information

Project Title	General Plant	*Project Number*	N/A
Year	2013	*Service Area*	All
Total Capital Cost	$3,897,320	*Category*	General Plant

II. Project Description

Description

The following table is a summary of General Plant capital expenditures in 2013:

General Plant	Expenditure
Building	$1,912,395
Computer Hardware	$274,903
Computer Software	$114,742
Vehicles	$1,329,696
General Equipment	$265,585

2013 Expenditures Include:

Building:

- Due to the new commercial development on McLeod Road, traffic congestion has increased dramatically on Pin Oak Drive. Third party consultants were retained at the beginning of 2012 and a detailed review of the property was completed. The result of the review was to relocate the wire out of stores into a non-heated wire building with an overhead crane and a drive through access. Wire will only be handled once when received and once when issued and in both processes via an overhead crane. The new wire building is located directly behind stores in the yard. The building is 14,400 square feet and includes 6 bays for vehicle and equipment storage on both sides of the building. The total cost includes the foundations, gravel, overhead doors, electrical and mechanical components. Wire will be stored and issued in a safe and timely manner. $907K.
- High Mast Lighting of the yard options were reviewed extensively. Four, 70 feet high mast lighting structures with 8 luminaries each were included in the 2013 budget. The budget amount includes the foundations and electrical controls with dual mode illumination levels and automated control with motorized lowering devices for maintenance. $435K.
- Traffic congestion has increased dramatically on Pin Oak Drive with new streetlights being installed at the north end of Pin Oak. With this anticipated increase in the volume of traffic, there

will be an added risk in moving NPEI's equipment in and out of the Niagara Falls service yard using the front driveway. With some upgrades to the rear driveway out to Kalar Road, some additional drainage installed along with an electric fence at the Kalar entrance NPEI can greatly reduce the hazard that this additional volume of traffic will bring in moving our fleet and equipment around on a day to day basis. Along with this would become the new entrance for shipping and receiving. Currently, NPEI has an access opportunity to Kalar Road and has budgeted for the construction of a new secure entrance for its operations and engineering departments to access the Niagara Falls service centre from Kalar Road versus Pin Oak Drive. In 2013, NPEI completed the necessary yard excavation in order that the new entrance may be paved in 2014. 533K.

Computer Hardware:

- New and replacement servers. $45K.
- Back-up Internet Link. $143K.
- PCs, laptops, notebooks, monitors and printers. $46K.

Computer Software:

- Harris Northstar CIS. $9K.
- Apollo Workflow. $57K.
- Engineering Ground Grid software. $9K.

Vehicles:

- 5 x Ford F-150 pick-up trucks. $150K.
- Nissan Titan pick-up. $30K.
- 65' RBD. $398K.
- 55' Aerial Manlift. $329K.
- 45' Material Handling Aerial Manlift. $284K.
- Dump / Hook Truck. $130K.

General Equipment:

- Equipment for new wire building. $141K.
- New entrance gate. $22K.
- Office furniture. $6K.
- Tools for line trucks. $22K.
- Traffic signs. $6K
- Grounds. $7K.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers
• **Business Operations Efficiency** • **Distribution System Operation Support**

Project #	2014-General Plant	Reference #	

I. General Information

Project Title	General Plant	*Project Number*	N/A
Year	2014	*Service Area*	All
Total Capital Cost	$3,267,235	*Category*	General Plant

II. Project Description

Description

The following table is a summary of General Plant capital expenditures in 2014:

General Plant	Expenditure
Building	$1,500,485
Computer Hardware	$297,040
Computer Software	$498,710
Vehicles	$672,000
General Equipment	$299,000

2014 Expenditures Include:

Building:

- The Niagara Falls stores area will be renovated. The new operations area and meter shop will be relocated to part of the current stores area. Approximately 8,000 square feet will house 5 offices, a Lead Hand area, the Operations Assistant workstation, a planning room, record storage room, mud room, locker room, washroom facilities, line tool storage area, maintenance area, and meter shop. The remaining 6,000 square feet of the existing space will be for the small stores area. $1,113K.
- The high mast lighting in the Niagara Falls yard will be completed. $198K.
- The new entrance from Kalar Road will be paved. $120K.
- 20 new parking spaces will be added to the south side of the Niagara Falls building. $70K.

Computer Hardware:

- New and replacement servers. $128K.
- Network switches. $24K.
- Cell phones. $23K.
- PCs, laptops, notebooks, monitors and printers. $81K.

Computer Software:

- Barcoding Software. $50K.
- File Nexus conversion. $50K.
- Disaster Recovery software. $50K.
- Backup and UPS upgrade. $47K.
- Microsoft Dynamics GP. $40K.
- Malware Protection. $40K.
- Automation Platform. $25K.
- Apollo Workflow. $25K.
- Cognos Reports. $25K.
- Exchange Migration $25K.
- Bill Presentment changes. $24K.
- Professional / Programming fees. $60K.

Vehicles:

- 55’ Double Bucket Material Handling Aerial Manlift. $350K.
- 46’ Material Handling Aerial Manlift. $300K.
- 65’ Pole Trailer. $22K.

General Equipment:

- Office furniture for new operations area. $70K.
- Other office furniture. $9K.
- Photocopier. $20K.
- Security cameras. $36K.
- Defibrillators. $13K
- Inventory Racking. $75K.
- Tools for line trucks. $10K.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Business Operations Efficiency**
- **Distribution System Operation Support**

APPENDIX N

2015 – 2019 Project Narratives

Niagara Peninsula Energy Inc

Capital Project Summary

Forecast Years

2015 - 2019

System Access

Project #	2015-0001	Reference #	SA-55

I. General Information

Project Title	Niagara Parks Commission Primary Network	*Project Number*	2015-0001
Year	2015	*Service Area*	All
Total Capital Cost	$818,905	*Category*	System Access

II. Project Description

Description

The Niagara Parks Commission (NPC) is a Provincial entity located within the City of Niagara Falls which oversees all operations associated with the tourist attractions under their jurisdiction. This also includes a significant electrical distribution system within its boundaries. Negotiations are currently underway, initiated by the Customer, for NPEI to assume the primary distribution system up to the low voltage bushings of the transformers. The NPC does not have staff qualified to operate and maintain the high voltage system, and would like to expand upon an operating agreement currently executed between both parties, where NPEI would own, maintain, and operate the high voltage system on their behalf. From the Customers due-diligence standpoint, and NPEI's capability to respond to the Customers emergency and growth requirements, with appropriate staff, equipment, and material stock, a mutually beneficial system expansion would result, increasing public safety and reliability.

Map Overview

Evaluation Criteria
Reliability/Performance: Assuming control of the primary distribution system through NPC corridors provides additional back-feed capabilities to the benefit of both parties and their customers. Restoration times will be significantly improved with this added level of flexibility. **Efficiency:** Control of this additional primary distribution system allows for optimization of system configuration to service major load centers in the area. This optimization will result in an overall reduction in loss component on the distribution system. **Safety:** NPEI's ability to respond to emergency situations in this high traffic tourist area with qualified staff and equipment improves public safety and contingency response in the area. **Community Relations:** Incorporation of NPC plant into NPEI's distribution system provides additional security in the electrical supply in the area in terms of accommodating growth, maintenance of equipment, and contingency response.

Drivers
• **Distribution system expansion** • **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2015-1008	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	***Project Number***	**2015-1008**
Year	**2015**	***Service Area***	**All**
Total Capital Cost	**$1,007,500**	***Category***	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2015-1009	Reference #	

I. General Information

Project Title	**Subdivision - Distribution System Expansion**	*Project Number*	**2015-1009**
Year	**2015**	*Service Area*	**All**
Total Capital Cost	**$587,004**	*Category*	**System Access**

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2015-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works**	*Project Number*	**2015-Various**
Year	**2015**	*Service Area*	**All**
Total Capital Cost	**$500,000**	*Category*	**System Access**

II. Project Description

Description

There are various projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2016-0001	Reference #	SA-63

I. General Information

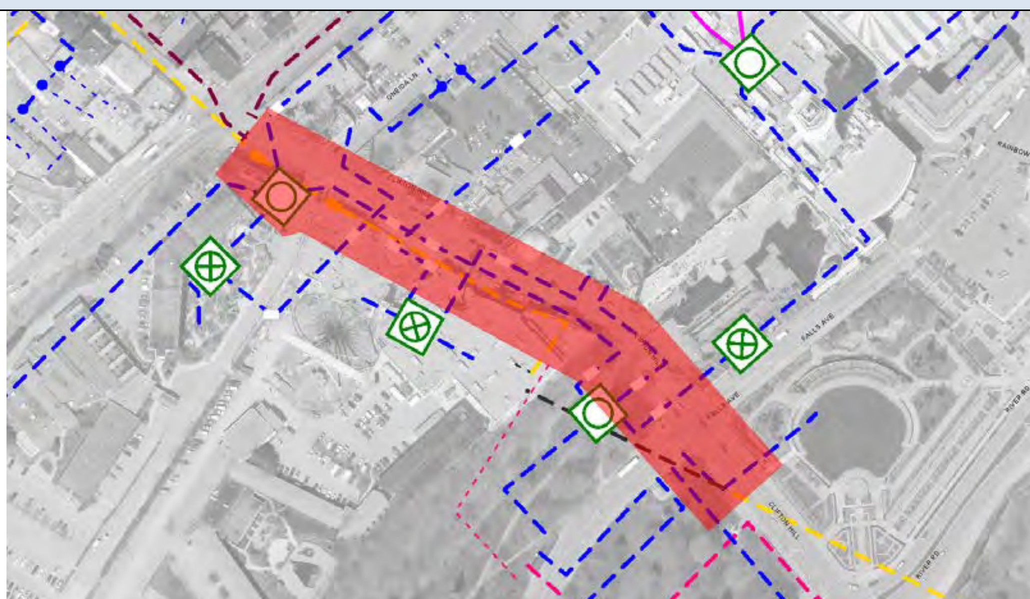
Project Title	**Clifton Hill Primary Upgrade**	***Project Number***	**2016-0001**
Year	**2016**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$272,874**	***Category***	**System Access**

II. Project Description

Description

Clifton Hill is a famous entertainment destination within the tourist core of Niagara Falls. Development upgrades currently underway have presented an opportunity for the abandonment of a 5kV feeder within an existing duct structure, which if removed, would allow for the installation of a 600 amp 15kV circuit to deal with future load growth. Project scope involves the replacement of 0.5kM of existing 1/0 Cu underground 5kV primary cable installed in 1985. This existing 5kV cable will be decommissioned and replaced with a new 600kcMIL Cu 15kV underground primary feeder. The new cable will utilize existing ductwork where possible. The project scope also includes replacement of an existing switchgear (Stn. #159) to facilitate an additional un-fused way. Benefits include improved system losses, reinforcement and capacity increase of the distribution system in the tourist core.

Map Overview



Evaluation Criteria
Reliability/Peforrmance: The addition of a main feeder in this area will provide intertie between the 3M28 and 3M29 feeders providing increased flexibility during contingencies. Additional back-feed capability will be introduced into tourism based loads in the area. **Efficiency:** Additional circuit tie's will reduce response and restoration times in outage scenarios. Additionally, the larger cable will replace an express feeder that is at capacity resulting in overall loss reduction. **Safety:** The increased capacity in the Clifton Hill area will alleviate loads on existing cables which are installed in sidewalk vaults. This reduces the likelihood of a cable fault in a vault located under high volumes of pedestrian traffic. **Community Relations:** The addition of capacity in this high traffic area benefits the security of electrical distribution for connected loads.
Drivers
• **Reliability** • **Loss Reduction** • **Capacity** • **Safety** • **Efficiency**

Project #	2016-0002	Reference #	SA-64

I. General Information

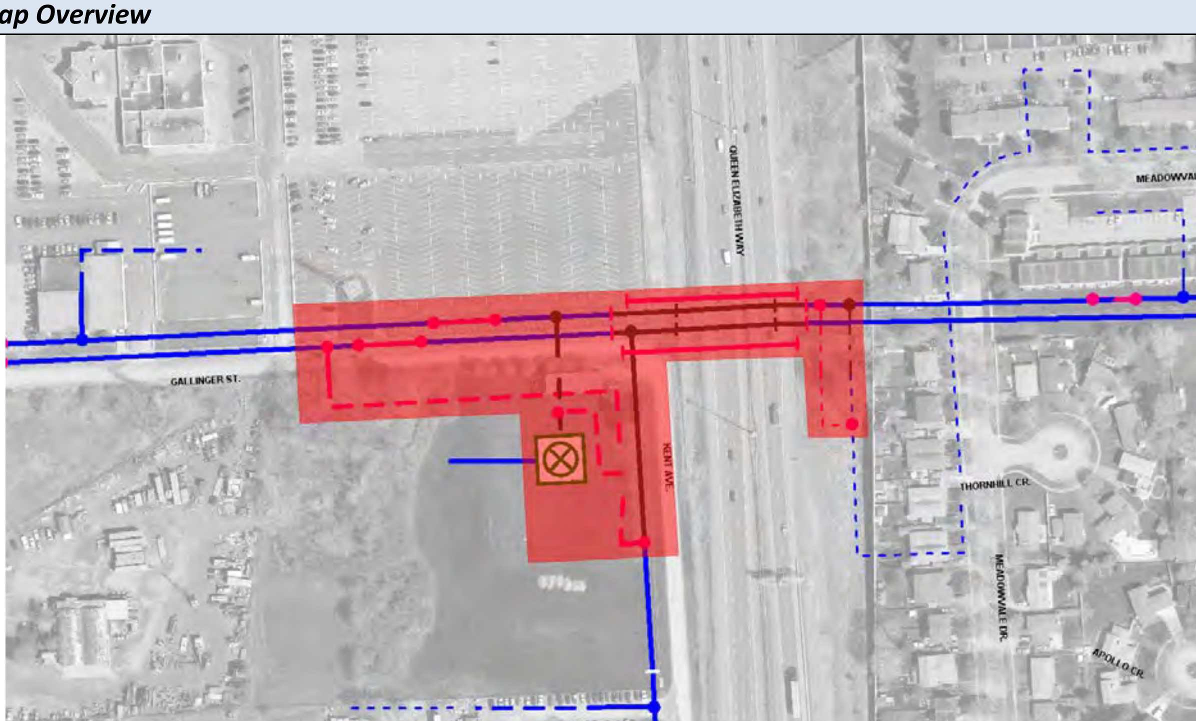
Project Title	N.S.&T. R.O.W. Crossing at the QEW	*Project Number*	2016-0002
Year	2016	*Service Area*	Niagara Falls
Total Capital Cost	$313,157	*Category*	System Access

II. Project Description

Description

Due to a previous pole fire and future MTO widening proposals, the need has arisen to replace an existing overhead single pole, double circuit 15KV primary structure crossing the Q.E.W. south of Thorold Stone Road with a double pole structure and removal of the plant located within the MTO R.O.W. This will facilitate the future widening by the MTO utilizing CSA Grade 1 standard construction with concrete poles, increasing public safety by eliminating future pole fire possibilities, and constructing to present day standards with increased spacing to facilitate joint-use attachments on the structure.

Map Overview



Evaluation Criteria
Reliability/Peforrmance: Re-construction of these section of double circuit line with concrete poles eliminates the possibility of pole fires in an area prone to road salt contamination. Additional sectionalizing devices are also in the scope of the project providing greater flexibility during continencies. **Efficiency:** The addition of sectionalizing devices improves back-feed capability and restoration time under outage conditions. **Safety:** Construction to Grade 1 standards applicable to MTO highway crossings greatly enhances public safety related to the surrounding traffic in the area. **Community Relations:** Coordination of work with MTO requirements minimizes disruption to traffic in this area.
Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2016-1008	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	*Project Number*	**2016-1008**
Year	**2016**	*Service Area*	**All**
Total Capital Cost	**$1,007,500**	*Category*	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2016-1009	Reference #	

I. General Information

Project Title	**Subdivision - Distribution System Expansion**	*Project Number*	**2016-1009**
Year	**2016**	*Service Area*	**All**
Total Capital Cost	**$587,004**	*Category*	**System Access**

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2016-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works**	*Project Number*	**2016-Various**
Year	**2016**	*Service Area*	**All**
Total Capital Cost	**$500,000**	*Category*	**System Access**

II. Project Description

Description

There are various projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2017-1008	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	*Project Number*	**2017-1008**
Year	**2017**	*Service Area*	**All**
Total Capital Cost	**$1,007,500**	*Category*	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2017-1009	Reference #	

I. General Information

Project Title	Subdivision - Distribution System Expansion	*Project Number*	2017-1009
Year	2017	*Service Area*	All
Total Capital Cost	$587,004	*Category*	System Access

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2017-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works**	*Project Number*	**2017-Various**
Year	**2017**	*Service Area*	**All**
Total Capital Cost	**$500,000**	*Category*	**System Access**

II. Project Description

Description

There are various projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2018-0001	Reference #	SA-82

I. General Information

Project Title	**Concession 2 Rd. Between Caistorville Rd. and Westbrook Rd.**	***Project Number***	**2018-0001**
Year	**2018**	***Service Area***	**West Lincoln**
Total Capital Cost	**$270,368**	***Category***	**System Service**

II. Project Description

Description

Project scope involves extension of 1.25km of a rural overhead single phase primary distribution line from pole #43791 west to opposite pole #43907 to decommission 2.7km of 4.8kV distribution line presently located on private property (through farm field), without easement documentation, and poor access, installed in 1947. Install 21-new 40' wooden poles with a removal of 32 poles. Existing loads will be serviced from the Road Allowance. System benefits include improved reliability and emergency response, with removal of inaccessible line upon completion.

Map Overview

Evaluation Criteria
Reliability/Performance: Access to the existing, off-road primary distribution line is suspect and requires entrance through private property. Relocation of the line to the road allowance provides NPEI direct access for inspection, maintenance and tree clearing purposes. **Efficiency:** Improved accessibility will reduce response and restoration durations in the event of an outage. **Safety:** The majority of the existing poles slated for replacement are at end of life based on asset condition assessment. Removal of these facilities eliminates hazard associated with structural failure in a space frequently accessed by the public. **Community Relations:** Removal of the deteriorated apparatus and relocation to the road allowance eliminates the negative impacts caused by NPEI plant on the surrounding area.
Drivers
• **Access** • **Reliability** • **Capacity** • **Safety** • **Efficiency**

Project #	2018-1008	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	*Project Number*	**2018-1008**
Year	**2018**	*Service Area*	**All**
Total Capital Cost	**$1,007,500**	*Category*	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2018-1009	Reference #	

I. General Information

Project Title	**Subdivision - Distribution System Expansion**	*Project Number*	**2018-1009**
Year	**2018**	*Service Area*	**All**
Total Capital Cost	**$587,004**	*Category*	**System Access**

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2018-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works**	*Project Number*	**2018-Various**
Year	**2018**	*Service Area*	**All**
Total Capital Cost	**$500,000**	*Category*	**System Access**

II. Project Description

Description

There are various projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

Project #	2019-1008	Reference #	SA-42

I. General Information

Project Title	**Demand Based Reinforcements, Customer Connections, New/Upgrade Services**	***Project Number***	**2019-1008**
Year	**2019**	***Service Area***	**All**
Total Capital Cost	**$1,007,500**	***Category***	**System Access**

II. Project Description

Description

Demand Based Reinforcements are required to permit the construction of new distribution facilities to service commercial customers.

Customer Connections are required to permit the expansion of distribution facilities for the connection of new residential customers in subdivision developments.

New/Upgraded Services are tracked under various projects in order to permit the expansion of distribution facilities to connect residential customers outside of subdivision developments.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential and commercial customers**

Project #	2019-1009	Reference #	

I. General Information

Project Title	**Subdivision - Distribution System Expansion**	***Project Number***	**2019-1009**
Year	**2019**	***Service Area***	**All**
Total Capital Cost	**$587,004**	***Category***	**System Access**

II. Project Description

Description

This project represents assets assumed through subdivision and row housing development. Following a 1 year warranty period from the date of connection, NPEI assumes the subdivision development as an expansion of its distribution system.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
N/A

Drivers

- **Distribution system expansion**
- **Connection of new residential customers**

Project #	2019-Various	Reference #	SA-43

I. General Information

Project Title	**Line Relocation due to Municipal Works**	*Project Number*	**2019-Various**
Year	**2019**	*Service Area*	**All**
Total Capital Cost	**$500,000**	*Category*	**System Access**

II. Project Description

Description

There are various projects driven by municipal or regional road works that require coordination with NPEI. Coordination is required to eliminate conflicts between NPEI plant and municipal / regional infrastructure.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
N/A
Efficiency:
N/A
Safety:
N/A
Community Relations:
Coordinating distribution system upgrades with municipal works minimizes disruption to affected customers in the area.

Drivers

- **Municipal Road Works**

System Renewal

Project #	**2015-0001**	**Reference #**	**SR-24**
I. General Information			
Project Title	**Crawford Street Rebuild - Thorold Stone to Sheldon - Carry Over**	***Project Number***	**2015-0001**
Year	**2015**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$282,324**	***Category***	**System Renewal**
II. Project Description			
Description			
See 2014 Project Description			
Map Overview			
See 2014 Map Overview			
Evaluation Criteria			
See 2014 Evaluation Criteria			
Drivers			
See 2014 Drivers			

Project #	2015-0003	Reference #	SR-60

I. General Information

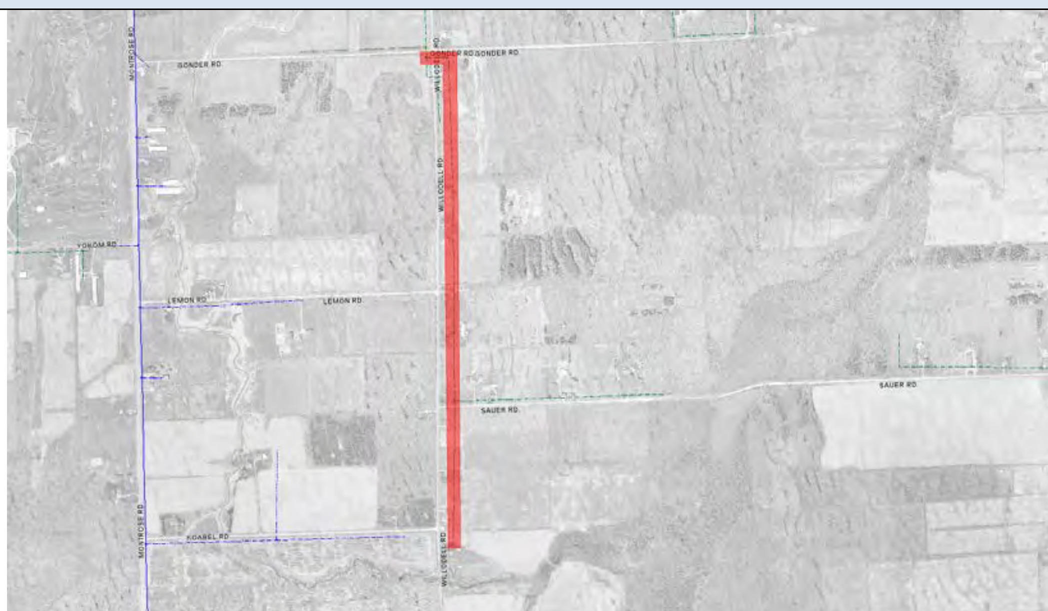
Project Title	**Willodell Road - Gonder to Koabel Road**	***Project Number***	**2015-0003**
Year	**2015**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$310,710**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves replacement/relocation of 1.5km of rural overhead 2.4kV (RECL-2) off-road primary line with an overhead 15kV class single phase line relocated within the Willodell road allowance between Gonder Rd & Koabel Rd. Installation of 27 new 45' wood poles, 6-25KVA transformers and the transfer 8 existing services. System benefits include the replacement of aging equipment originally installed in 1949, constructed on private property, by Ontario Hydro, without registered easements in favor of the Utility, relocation of inaccessible infrastructure, future capability of conversion to 15KV with clearance sufficient to construct 3-phase if required, improved reliability and reduced response time due to improved equipment access.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2015-0004	Reference #	SR-58
I. General Information			
Project Title	**Willoughby Drive - Main Street to Cattell Drive**	***Project Number***	**2015-0004**
Year	**2015**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$372,190.81**	***Category***	**System Renewal**
II. Project Description			
Description			
Project scope involves the replacement of 1.2 km of urban overhead 13.8 KV primary line installed in 1960. It consists of 17-new 45’ wood poles framed for 3-phase, 10-new 40' wood poles framed for single phase and re-conductor the existing 3/0 aluminum primary with 556 kcMIL conductor. The circuit will be constructed in the same alignment as the existing pole line with the installation of 7 single phase and 1 three phase transformer to replace existing, the installation of 1.1km of secondary buss, and transfer of 34 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the main distribution line.			
Map Overview			
			

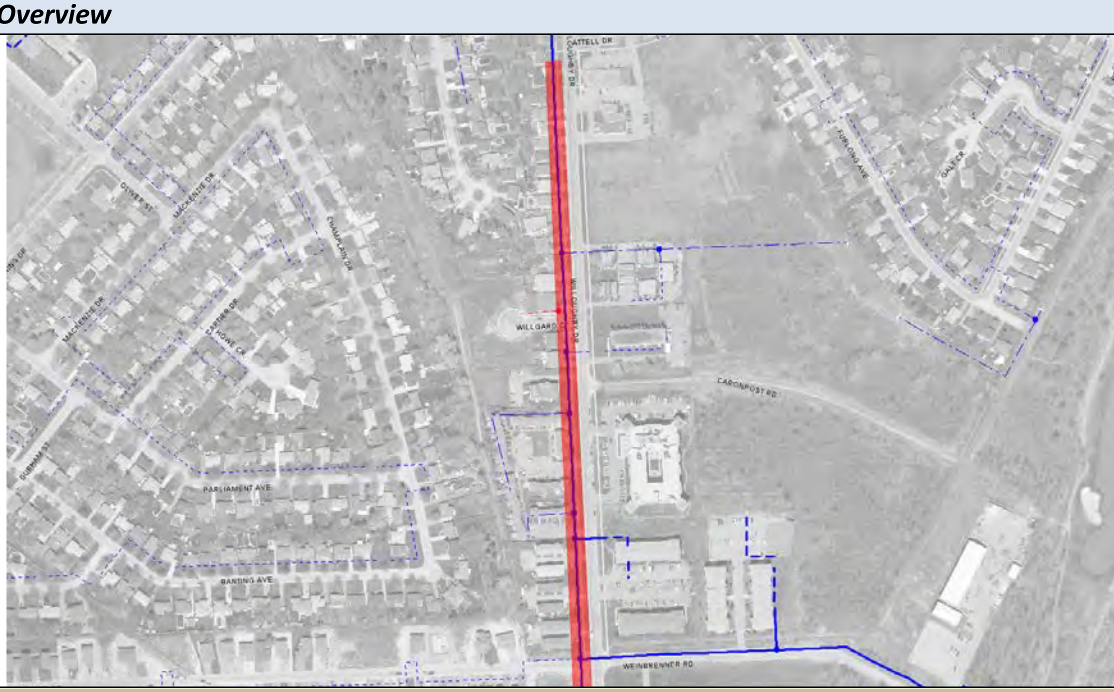
Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life** • **Loss Reduction**

Project #	2015-0005	Reference #	SR-59
I. General Information			
Project Title	**Willoughby Drive - Cattell Drive to Weinbrenner Road**	***Project Number***	**2015-0005**
Year	**2015**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$383,293**	***Category***	**System Renewal**
II. Project Description			

Description

Project scope involves the replacement of 0.7km of urban overhead 13.8kV primary line installed in 1969 with 21-new 45’ wood poles framed for 3-phase & 4-new 40' wood poles framed for single phase. It includes re-conductor of the existing 3/0 aluminum primary with 556 kcMIL. The circuit will be constructed in the same alignment as the existing pole line with the installation of 5 single phase and 1 three phase transformer to replace existing, the installation of 0.7km of secondary buss, and transfer of 30 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement of supply to a sensitive load (large Senior Care Facility) .

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life** • **Loss Reduction**

Project #	2015-0007	Reference #	SR-7

I. General Information

Project Title	**Station 22 South Rebuild - Phase 1 Carry Over / Phase 2**	*Project Number*	**2015-0007**
Year	**2015**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$143,724 $507,139**	*Category*	**System Renewal**

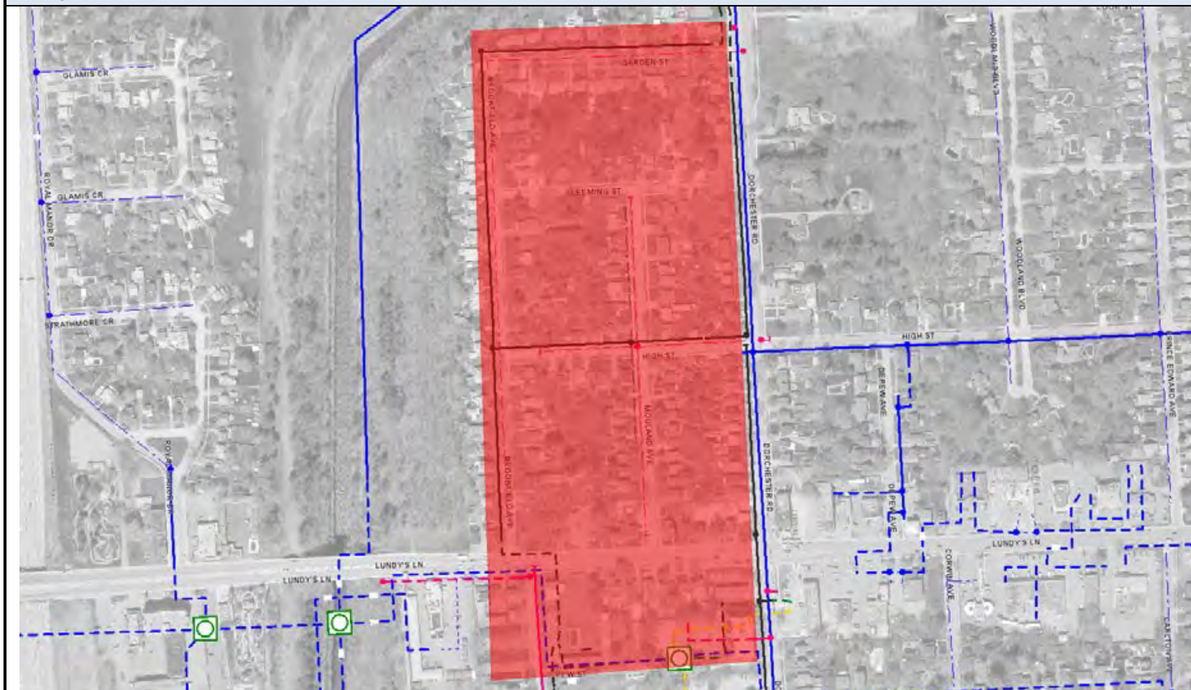
II. Project Description

Description

This project is part of a rebuild program directed at overhead distribution facilities identified as nearing the end of life expectancy. Areas are identified based on the results of NPEI's asset condition assessment (ACA). While NPEI does manage a replacement program for poles on an individual basis, in some areas a large quantity of deficiencies exist on assets of similar age and condition. In these cases, it is more feasible to replace facilities holistically. Areas targeted for the program are prioritized based on health index results from the NPEI's ACA. In the identified areas, the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2015 this program targets the 2-areas listed below with the first being a carry-over from 2014 and the latter being the second phase for the elimination of Municipal Sub-Station #22.

For the 2014 carry over, this program targets the remainder of 1.7 kilometers of urban distribution line installed in 1960, including 58 pole changes, new single phase primary and secondary circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 125 residential customers in the area bounded by Dorchester Rd., Lundy's Lane, Coach Drive, Clare Crescent, Brookfield Avenue & Barker Street.

For Phase II, the program targets 1.20 kilometers of urban distribution line installed in 1953, including 38 pole changes, new single-phase (1.2km) and secondary (1.4km) circuits, 8 distribution transformer replacements resulting in the upgraded supply to about 119 residential customers directly. The area is bounded by Dorchester Rd., Lundy's Lane, Brookfield Ave., and Garden St. System benefits include reconstruction to eliminate municipal station #22 constructed in 1969, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities, improved equipment clearance, and increased customer reliability.

Map Overview


Evaluation Criteria
Reliability/Performance: The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. New standards for single phase distribution incorporate covered primary conductor installed with an increase in the point of attachment. The covered conductor is capable of withstanding momentary tree contact without disruption of service. **Efficiency:** This area will be converted from 4.16kV to 13.8kV. Conversion of this area contributes to the elimination of two 4.16kV feeders. Both the feeder elimination and voltage conversion will contribute to a reduction in system losses. **Safety:** The project involves the replacement of poles at a substandard height. New construction includes the installation of 40' poles for the attachment of covered primary conductor. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.

Drivers
• **Sustainment** • **Replacement of Assets at End of Life**

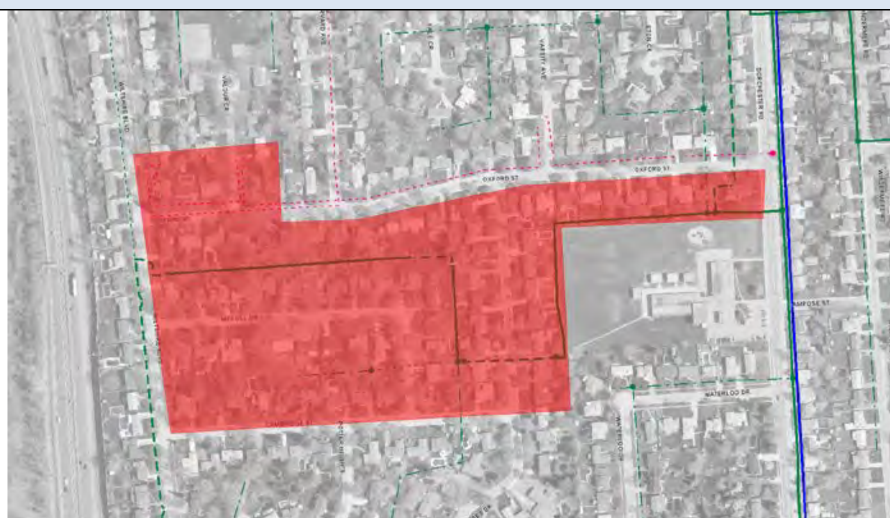
Project #	2015-0008	Reference #	SR-28
I. General Information			
Project Title	Rolling Acres OH to UG Conversion - Phase 2	*Project Number*	2015-0008
Year	2015	*Service Area*	Niagara Falls
Total Capital Cost	$570,500.09	*Category*	System Renewal

II. Project Description

Description

Phase II project scope involves the relocation of primary facilities located on an inaccessible rear lot pole line within private property for which easement documentation is available. 1.0KM of primary duct by directional boring technology to 5 pad-mounted transformers placed on precast pads within the road allowance. Secondary laterals will be directionally bored back to the rear lot easements, to source the 55 individual underground house services currently fed from junction boxes mounted on the distribution poles. The streets included within this phase are Oxford, McColl Drive, Cambridge Street, Rolling Acres Drive. The current equipment was installed in 1961 and tree growth, pool, shed and fencing installations, have made the line difficult to maintain and service. There have been many issues in this subdivision during Ice/Wind Storms. 15KV rated equipment will be installed for future voltage conversion, once all the phases have been completed.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2015-0009	Reference #	SR-57

I. General Information

Project Title	NWTS Metering Replacement	*Project Number*	2015-0009
Year	2015	*Service Area*	West Lincoln
Total Capital Cost	$289,605	*Category*	System Renewal

II. Project Description

Description

Due to several failures of the existing 230 KV primary metering units monitoring the DESN at the Niagara West Transformer Station, NPEI has identified a need for the replacement of the 2 primary metering units with 4-low voltage feeder metering units, minimizing system wide outages which occurred during the metering failures, providing improved reliability and accuracy of billing and settlement.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Reliability**
- **Assets at End of Life**

Project #	2015-0011	Reference #	SR-56

I. General Information

Project Title	**Frederica Street - Dorchester to Drummond Rebuild**	***Project Number***	**2015-0011**
Year	**2015**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$676,144**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 1.1km of existing 2/0 overhead 4.16kV (F-104) primary line installed in 1955 with 16-new 45' wood poles, utilizing 12-existing poles replaced previously. Includes re-conductor of the existing with 556 kcMIL 3-phase main circuit, constructed in the same alignment as the existing pole line. Also includes the installation of 4-new transformers, installation of 1.1km of secondary bus, and the transfer of 55 services. Benefits include the final stage of reconstruction to eliminate Municipal Station #22 which was constructed in 1969 and is targeted for decommissioning. Additional benefits are the provision for immediate voltage conversion opportunities of several existing lateral feeds, improved system losses, and improved equipment clearances.

Map Overview

Evaluation Criteria
Reliability/Performance: The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. **Efficiency:** This area will be converted from 4.16kV to 13.8kV. Conversion of this area contributes to the elimination of a municipal substation. The station elimination and voltage conversion will contribute to a reduction in system losses. **Safety:** The project involves the replacement of poles at a substandard height. New construction includes the installation of 45' increasing public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area.
Drivers
• **Sustainment** • **Replacement of Assets at End of Life** • **Loss Reduction** • **Capacity** • **Reliability**

Project #	2015-0015	Reference #	SR-26

I. General Information

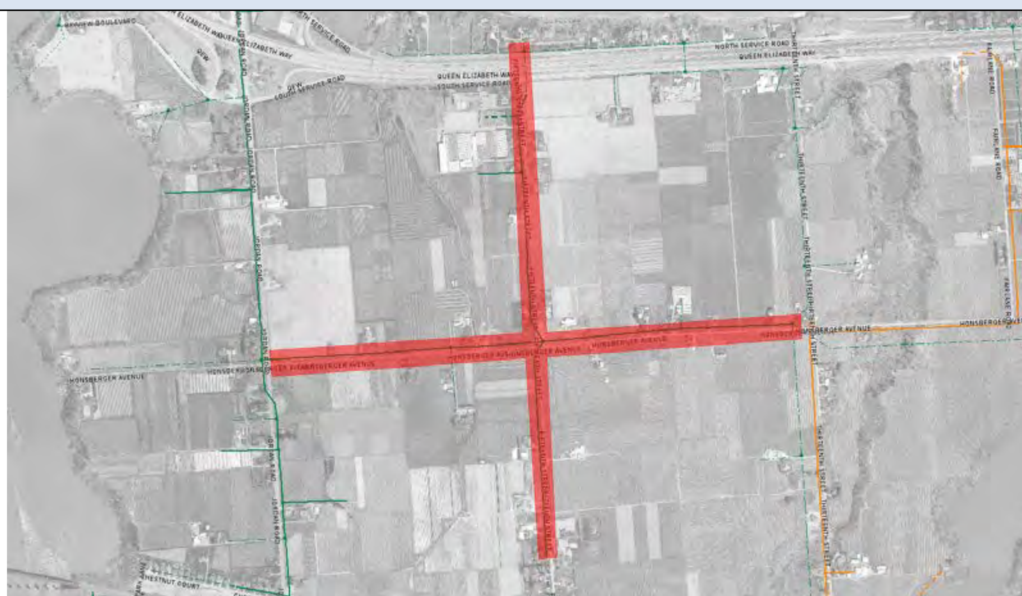
Project Title	**Jordan Road Rebuild Phase II - Honsberger from Jordan Road to Thirteenth Street**	***Project Number***	**2015-0015**
Year	**2015**	***Service Area***	**Lincoln**
Total Capital Cost	**$449,324**	***Category***	**System Renewal**

II. Project Description

Description

The Project Scope involves the second stage of rebuild of existing 3-phase 8320 Volt primary line, in place, constructed to 27.6kV standards for approx 2.0km involving the installation of 34-new 45' poles on Honsberger Rd from Jordan Rd to Thirteenth St., transfer of existing primary conductors, and installation of 2.0km of new neutral. The project was driven by the pole inspection program which has identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and provisions for future conversion to 27.6kV of the feeders supplied by Jordan M.S. for its eventual de-commissioning.

Map Overview

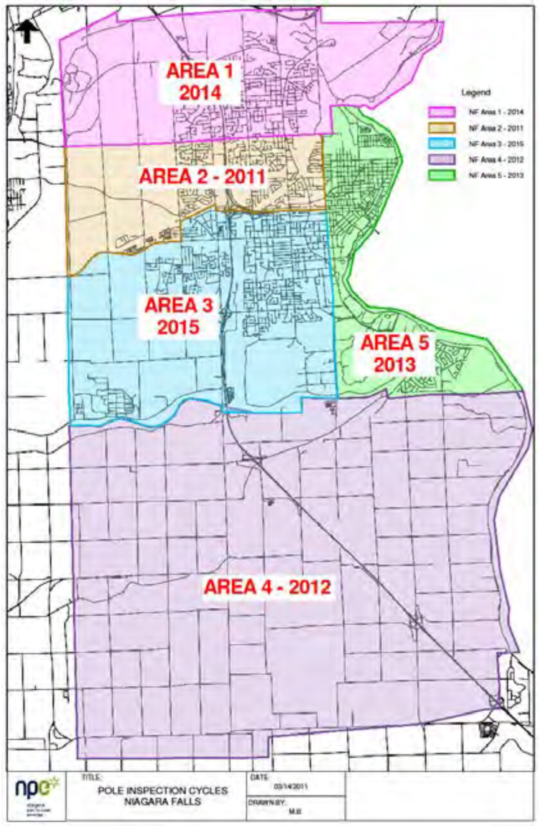


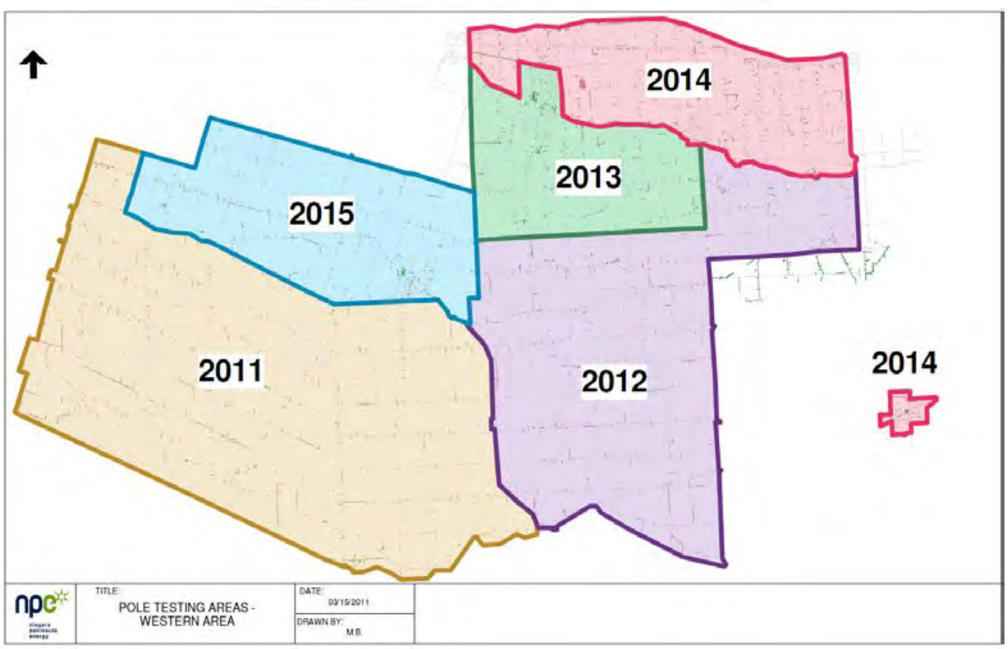
Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life**

Project #	2015-1007	Reference #	SR-30
I. General Information			
Project Title	**System Sustainment / Minor Betterments**	***Project Number***	**2015-1007**
Year	**2015**	***Service Area***	**All**
Total Capital Cost	**$680,000**	***Category***	**System Renewal**
II. Project Description			
Description			
Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.			
Map Overview			
N/A			
Evaluation Criteria			
N/A			
Drivers			
• **Sustainment** • **Unplanned failure of cables / equipment**			

Project #	2015-1010	Reference #	SR-31
I. General Information			
Project Title	**Pole Replacement Program**	***Project Number***	**2015-1010**
Year	**2015**	***Service Area***	**All**
Total Capital Cost	**$431,729**	***Category***	**System Renewal**
II. Project Description			
Description			
Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The 2015 Niagara test area is bounded in the West by the City Limits/Thorold Town Line Rd., South to the Welland River, East to Stanley Ave, North to Hwy #420/Beaverdams Road and includes 3693 poles total. The Western Service Territory test area is bounded by Mud Street to the north, south to Twenty Road, east to Walker Road, west to South Grimsby Road 20 and includes 3157 poles. Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.			

Map Overview





Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment / Poles at End of Life**

Project #	**2015-0020**	**Reference #**	**SR-32**
I. General Information			
Project Title	**Kiosk/Submersible Replacement Program**	***Project Number***	**2015-0020**
Year	**2015**	***Service Area***	**All**
Total Capital Cost	**$647,029**	***Category***	**System Renewal**

II. Project Description

Description

The Kiosk replacement program is an integral part of our underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. The locations are prioritized by the results of a Conditional Assessment Survey completed in 2013, which will be repeated on a 5-year cycle as required.

57 units remain on the 15KV System, and 74 units remain on the 5KV System. For 2015 the plan is to replace 10 units based on the historical replacement average.

Map Overview

N/A

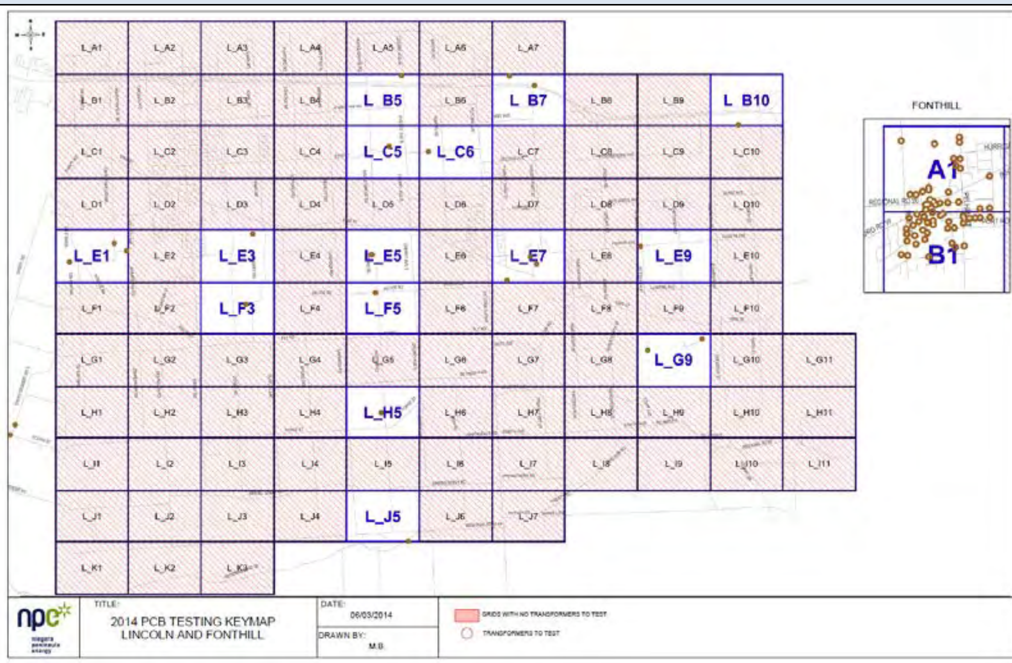
Evaluation Criteria

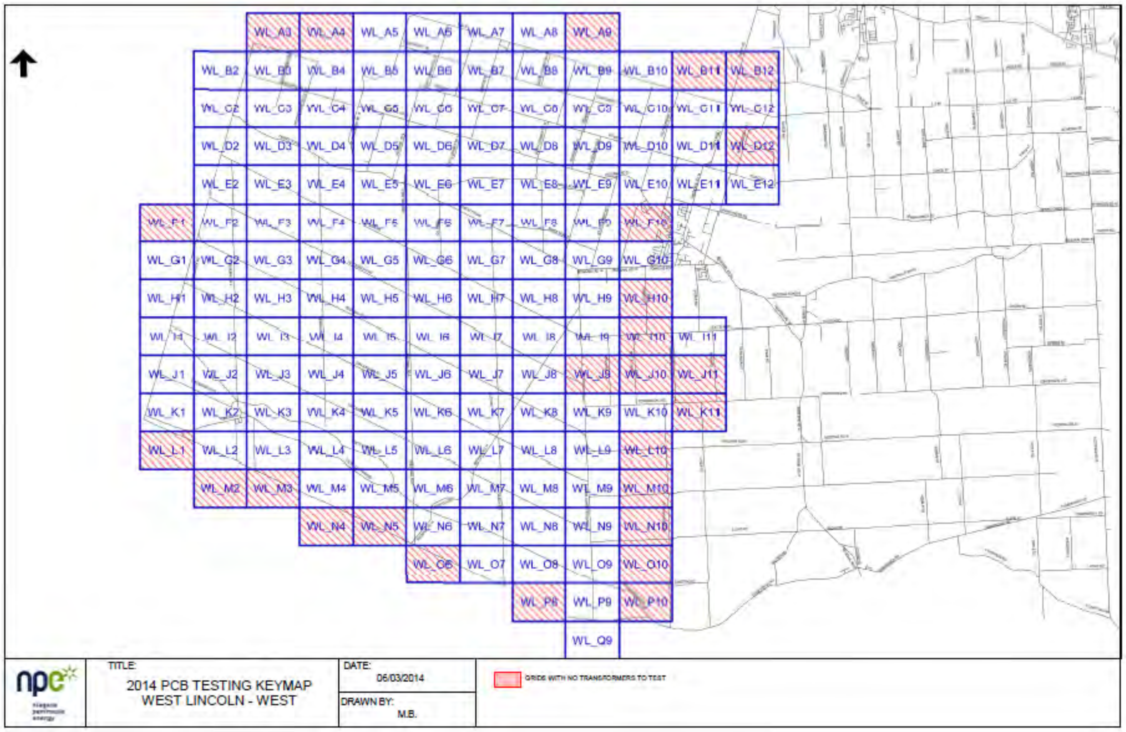
N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2015-2011	Reference #	SR-33
I. General Information			
Project Title	**PCB Transformer Replacement Program**	***Project Number***	**2015-2011**
Year	**2015**	***Service Area***	**All**
Total Capital Cost	**$495,104**	***Category***	**System Renewal**
II. Project Description			
Description			
The third and final phase of the three year transformer testing program has been completed in 2014 within the West Service Territory resulting in the requirement to replace approximately 50 units identified as having over the legislated limit of PCB content. The program will track these change-outs which will likely include the replacement of the pole supporting the unit with associated transfers, removals and disposal costs. Benefits include meeting the requirement of the legislation, and removal of the hazardous material from the system. The 2014 test area is shown below.			
Map Overview			





Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Public and Worker Safety**

Project #	2016-0003	Reference #	SR-65

I. General Information

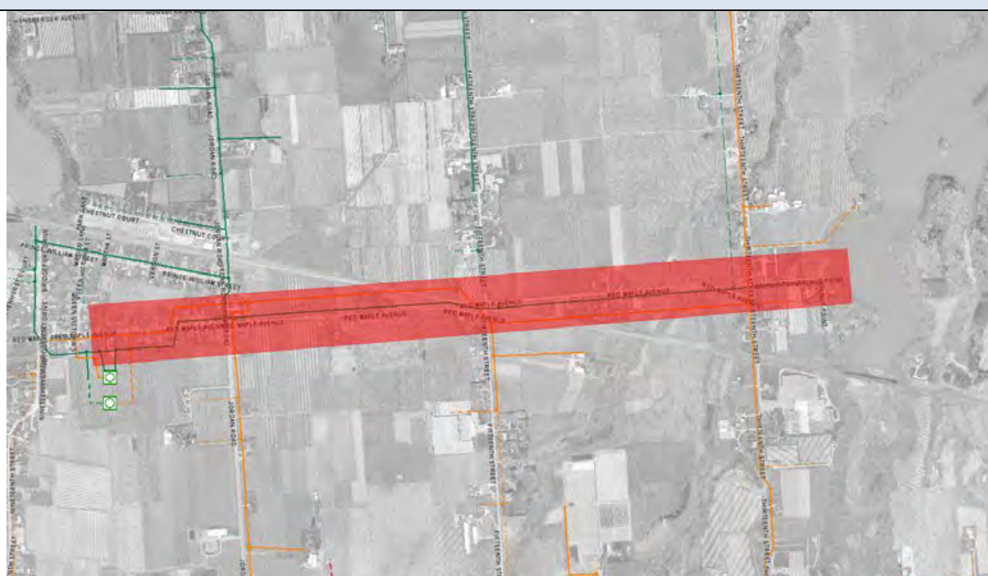
Project Title	Jordan Road Voltage Conversion Phase 3	*Project Number*	2016-0003
Year	2016	*Service Area*	Lincoln
Total Capital Cost	$429,504	*Category*	System Renewal

II. Project Description

Description

The Project Scope involves the last stage of rebuild of existing 3-phase 8320Volt primary line, in place, constructed to 27.6KV standards for approx 1.2km. It involves re-construction of approximately 21 poles and the installation of 3 new 45' poles on Red Maple from Jordan Rd to Thirteenth St., and transfer of existing primary conductors. The project also involves the replacement of 17 distribution transformers for connection to the 27.6kV system. The project was driven by the pole inspection program which has identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and conversion to the 27.6KV system leading to de-commissioning of Jordan DS.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life**

Project #	2016-0004	Reference #	SR-66

I. General Information

Project Title	**Dorchester Road Rebuild McLeod Road to Dunn Street**	*Project Number*	**2016-0004**
Year	**2016**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$672,097**	*Category*	**System Renewal**

II. Project Description

Description

Rebuild Project which targets 1.0km of urban distribution line installed in 1955, including 26 pole changes, new three phase (1.0km) primary and secondary (1.0km) circuits, 5-1Ph & 3-3 Ph distribution transformer replacements resulting in the upgraded supply to about 74 residential & 7 commercial customers directly. System benefits include replacement of aging equipment, future source for voltage conversions opportunities in the immediate area, improved equipment clearance, and increased customer reliability and capacity increase.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity**

Project #	2016-0008	Reference #	SR-28

I. General Information

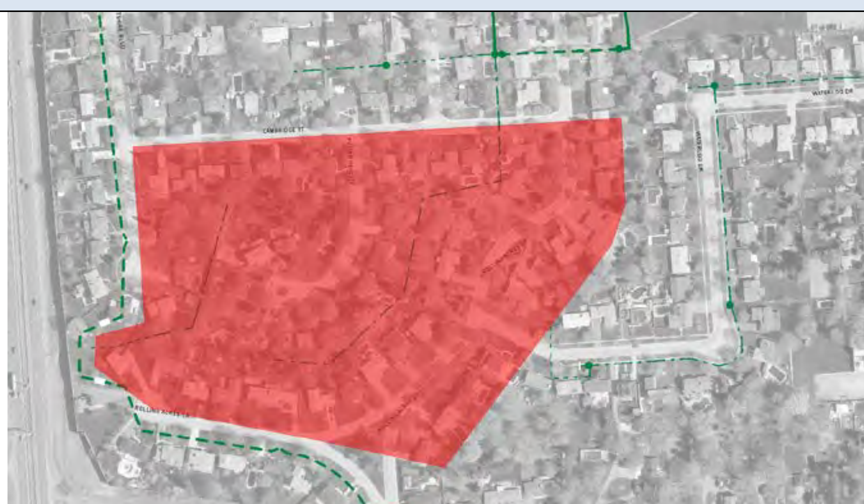
Project Title	**Rolling Acres OH to UG Conversion - Phase 3**	***Project Number***	**2016-0008**
Year	**2016**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$593,609**	***Category***	**System Renewal**

II. Project Description

Description

The final stage of the project scope involves the relocation of primary facilities located on an inaccessible rear lot pole line within private property, for which easement documentation is available. Installation of 0.8km of Primary duct by directional boring methods to 4 pad-mounted transformers placed on precast pads within the Road Allowance. Secondary laterals will be directionally bored back to the rear lot easements, to source the 40 individual underground house services currently fed from junction boxes mounted on the distribution poles. The streets included within this Phase include Potter Heights, Rolling Acres Drive and Rolling Acres Crescent. The current equipment was installed in 1958 and tree growth, pool, shed and fencing installations, have made the line difficult to maintain and service. There have been many issues in this subdivision during Ice/Wind Storm events. 15KV rated equipment will be installed for voltage conversion, once this phase has been completed. Improved Public safety, equipment accessibility, capacity increase, and voltage conversion are benefits realized through this Project.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Poles at End Of Life**

Project #	2016-1007	Reference #	SR-30
I. General Information			
Project Title	**System Sustainment / Minor Betterments**	***Project Number***	**2016-1007**
Year	**2016**	***Service Area***	**All**
Total Capital Cost	**$680,000**	***Category***	**System Renewal**

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2016-1010	Reference #	SR-31

I. General Information

Project Title	**Pole Replacement Program**	***Project Number***	**2016-1010**
Year	**2016**	***Service Area***	**All**
Total Capital Cost	**$872,112**	***Category***	**System Renewal**

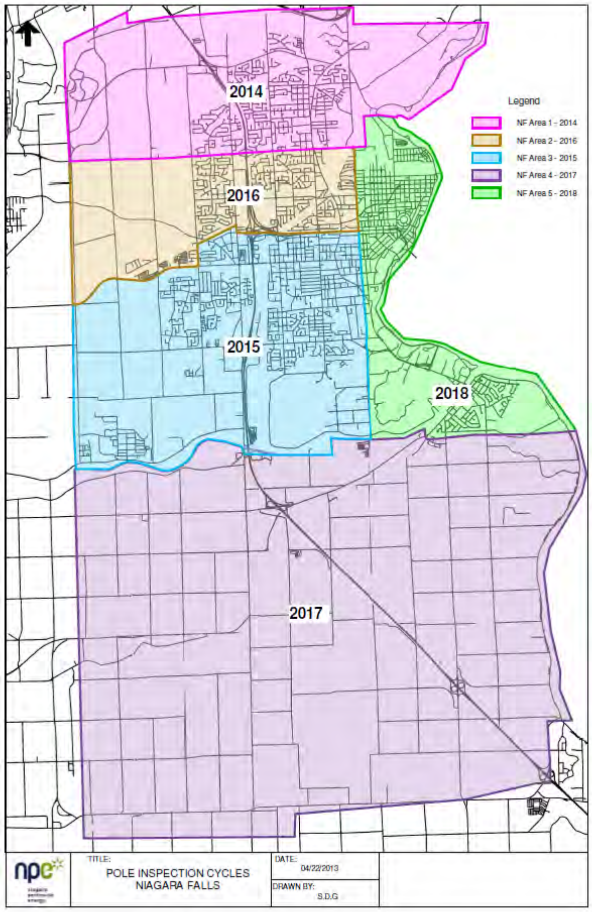
II. Project Description

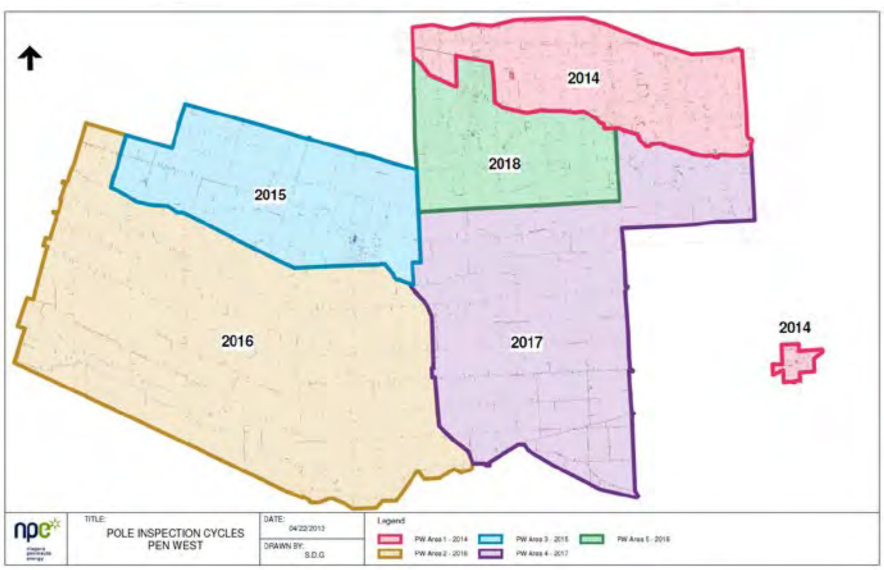
Description

Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The pole is tested for its integrity, a visual inspection is performed of the equipment installed on the pole by qualified Linesmen, the pole is photographed, guy guards are installed & down grounds are repaired/replaced as required, and test results are stored within the Corporate Geographic Information System. The 2016 Niagara test area is bounded in the West by the City Limits/Thorold Town Line Rd., South to the Welland River, and East to Stanley Ave, North to Hwy #420/Beaverdams Road and includes 3693 poles total. The Western Service Territory test area is bounded by Mud Street to the north, south to Twenty Road, east to Walker Road, and west to South Grimsby Road 20 and includes 3157 poles.

Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.

Map Overview





Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment / Poles at End of Life**

Project #	2016-0020	Reference #	SR-32

I. General Information

Project Title	**Kiosk/Submersible Replacement Program**	*Project Number*	**2016-0020**
Year	**2016**	*Service Area*	**All**
Total Capital Cost	**$841,137**	*Category*	**System Renewal**

II. Project Description

Description

Prior to the advent of pad-mounted Transformer & Switchgear Equipment, supplying loads larger than could be supplied by pole mounted equipment, or areas serviced from underground primary distribution systems, lead to the development of ground mounted masonry enclosures housing high voltage transformation, switching & protection apparatus, and secondary distribution equipment, known as the Kiosk. These block structures were meant to provide Public Safety, but over time, the structures deteriorate and warrant replacement. These are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2013.This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified. xx-Units remain on the 15KV System, and 74-Units remain on the 5KV System. For 2016 the plan is to replace 10 units based on the historical replacement average.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2017-0001	Reference #	SR-73

I. General Information

Project Title	**Thorold Stone Road Rebuild - Montrose to Kalar**	*Project Number*	**2017-0001**
Year	**2017**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$671,814**	*Category*	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 1.1km of urban overhead 13.8kV primary line installed in 1958 with 27-new 45’ wood poles, constructed in the same alignment as the existing pole line. Replacement of the undersized primary conductor with 556kcMIL for increased ampacity of the circuit during contingency situations, 6-single phase transformers to replace existing, transfer 4-three phase & 2-single phase primary risers, install 1.1km of secondary buss, and transfer of 40 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity**

Project #	2017-0002	Reference #	SR-74

I. General Information

Project Title	**Portage Rd. Rebuild - Mountain Road to Church's Lane**	***Project Number***	**2017-0002**
Year	**2017**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$455,289**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 0.6 km of urban overhead 13.8kV 3-phase primary line installed in 1966 with 17-new 45' wood poles, constructed in the same alignment as the existing pole line to provide a tie point between the 12-M-1 and the 12-M-4 from Stanley T.S. Replacement of the undersized primary conductor with 556kcMIL for increased ampacity of the circuit during contingency situations, 3-single phase transformers to replace existing, transfer 2-single phase & 2-three phase primary risers, install 0.6km of secondary buss, and transfer of 46 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area with redundancy provisions.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity**

Project #	2017-0003	Reference #	SR-75

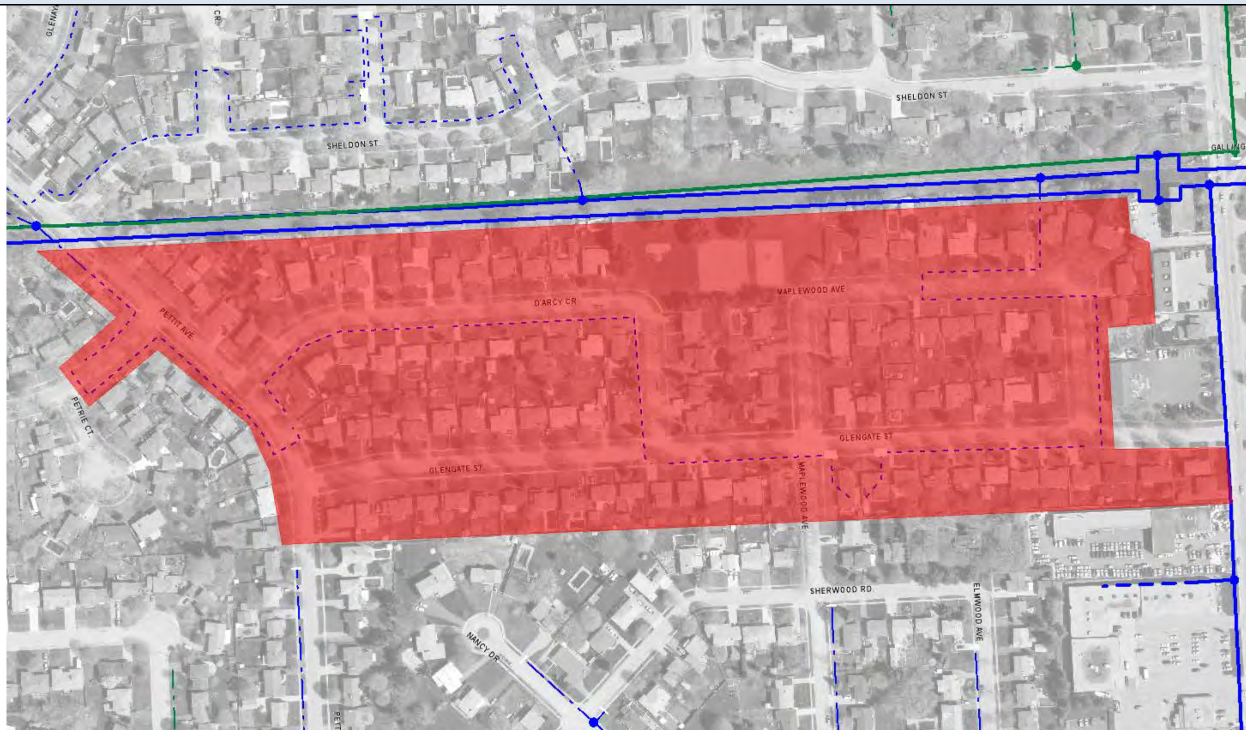
I. General Information

Project Title	**Subdivision Rehabilitation Phase 1**	***Project Number***	**2017-0003**
Year	**2017**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$490,301**	***Category***	**System Renewal**

II. Project Description

Description

Establishment of this Capital Program provides a solution to a problem identified during the last Asset Condition Assessment, for replacement of directly buried primary and secondary conductors supplying residential services within the oldest Underground Distribution Residential Subdivisions in the Niagara Falls service territory. The original installations were duct-less, making replacement difficult and costly. To extend lifecycles of the infrastructure NPEI recently completed a Program to replace the Submersible Transformers with Pad-mount Transformers. The program began in 1994 with approx 400 units converted in total. Sections of primary cable within the submersible enclosure, damaged by poor heat dissipation were spliced out and re-terminated, preventing failure. The cable was manufactured to a 133% insulation level, prolonging the life cycle, however, without a base value to compare the results of any cable testing, it is difficult to determine degradation since its installation. Expected lifespan of the cable is 35 years. To correct a noted deficiency in last Asset Assessment NPEI has entered installation dates, within the GIS, from design drawings, to help in prioritizing future replacement. The program would facilitate the installation, by directional boring methods, of a 4" & 3" HDPE conduit on the side of the road where primary and secondary co-exist, and a 4" HDPE conduit where only secondary is installed between all pad-mount foundations. Existing Cable will be "run to failure", at which time new cable would be installed under the Sustainment Budget . The first subdivision targeted was installed in 1967.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life**

Project #	2017-0004	Reference #	SR-76

I. General Information

Project Title	**Station St. DS Power TX Replacement**	*Project Number*	**2017-0004**
Year	**2017**	*Service Area*	**Fonthill**
Total Capital Cost	**$214,865**	*Category*	**System Renewal**

II. Project Description

Description

Project scope involves removal, transportation, and replacement of the 5000 kVA Power Transformer located at the Distribution Sub-Station. Under previous refurbishments the switchgear line-up and supply cables were upgraded, and the compound is equipped with an oil containment structure. The Station is one of two stations supplying the Town of Fonthill at 4.16kV without provisions for voltage conversion, due to Hydro One controlled supply points. The Station Transformer was manufactured in 1969.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment - End of Life Assets**

Project #	2017-0007	Reference #	SR-72

I. General Information

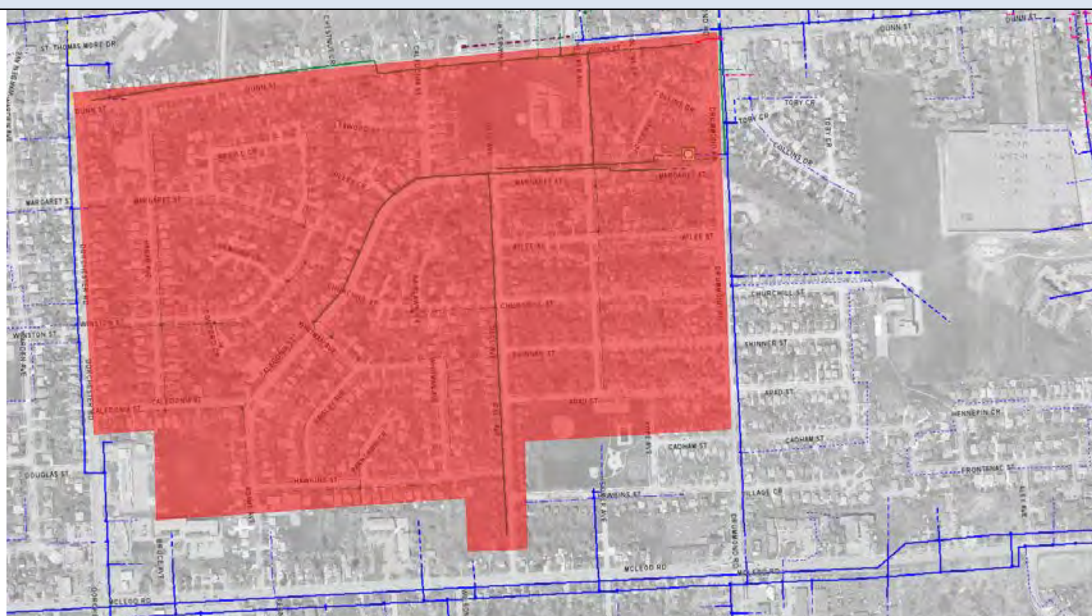
Project Title	**Station 14 Voltage Conversion Phase 1**	*Project Number*	**2017-0007**
Year	**2017**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$824,576**	*Category*	**System Renewal**

II. Project Description

Description

Rebuild Project which targets 1.20 kilometers of urban distribution line installed in 1956, including 34 pole changes, new three-phase (1.2Kkm) & secondary (1.2Kkm) circuits, 8-single and 2-Three phase distribution transformer replacements resulting in the upgraded supply to about 86 residential and 2-commercial customers directly, in the area bounded by Dunn St from Dorchester Rd to Drummond Road. System benefits include reconstruction to eliminate Municipal Sub-station Station #14 constructed in 1956, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities for approx 800kVA of connected load, improved equipment clearance, and increased customer reliability.

Map Overview



Evaluation Criteria
Reliability/Performance: The replacement of facilities at end of life with construction to NPEI's current standards will improve reliability in the area. New standards for single phase distribution incorporate covered primary conductor installed with an increase in the point of attachment. The covered conductor is capable of withstanding momentary tree contact without disruption of service. **Efficiency:** This area will be converted from 4.16kV to 13.8kV. Conversion of this area contributes to the elimination of two 4.16kV feeders. Both the feeder elimination and voltage conversion will contribute to a reduction in system losses. **Safety:** The project involves the replacement of poles at a substandard height. New construction includes the installation of 40' poles for the attachment of covered primary conductor. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Construction using improved appearance framing improves the overall aesthetics of NPEI plant present in the area. The use of covered primary cable reduces the amount of tree clearance required to conductors in the area minimizing the impact of vegetation management.
Drivers
• **Sustainment** • **Replacement of Assets at End of Life**

Project #	2017-0008	Reference #	SR-77

I. General Information

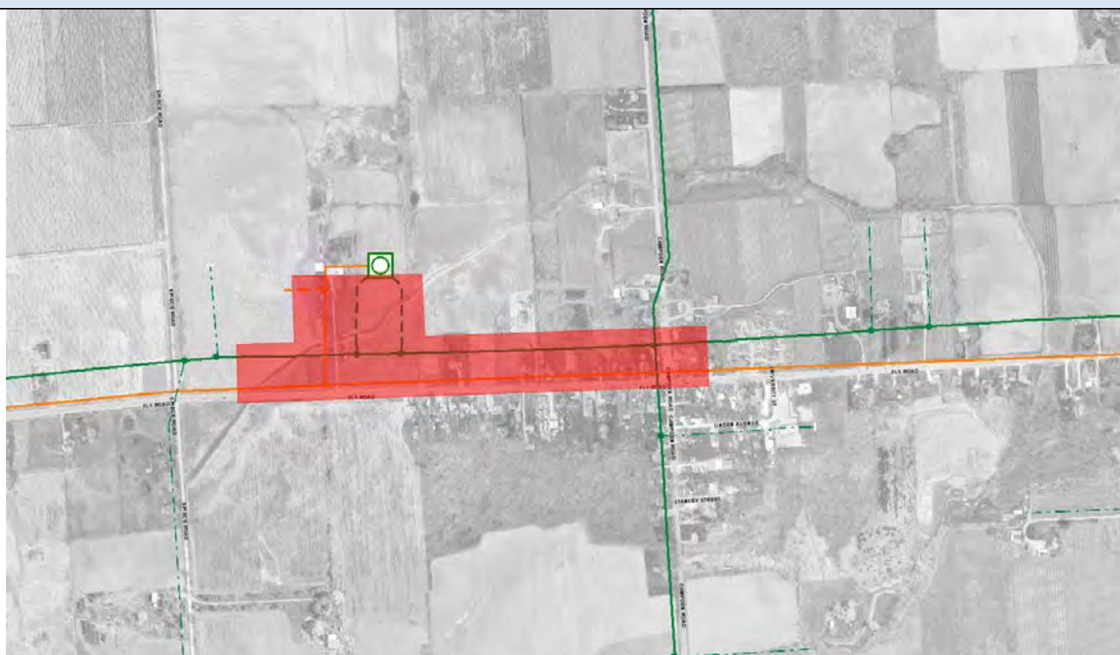
Project Title	**Campden DS Power TX Relocate**	***Project Number***	**2017-0008**
Year	**2017**	***Service Area***	**Lincoln**
Total Capital Cost	**$231,596**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves removal, transportation, and replacement of the 5000kVA Power Transformer located at the Distribution Sub-Station. Under previous refurbishments the switchgear line-up and supply cables were upgraded, and the compound is equipped with an oil containment structure. The Station Transformer has been targeted to be replaced with the Power Transformer from Jordan D.S., once all phases of the conversion work have been completed. The Station Transformer was manufactured in 1972 and has bushing gasket issues and metal particulate in the tap-changer compartment oil.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment - End of Life Assets**

Project #	2017-0009	Reference #	SR-78

I. General Information

Project Title	**Kalar TS Protection Refurbishment**	***Project Number***	**2017-0009**
Year	**2017**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$400,000**	***Category***	**System Renewal**

II. Project Description

Description

Kalar TS was placed in service in 2004 to service areas of Niagara Falls experiencing residential and commercial growth. The station consists of 2 x 75 MVA power transformers connected to the Hydro One transmission system at 115kV. The existing relays, RTU, and associated protection and control (P&C) equipment are at end of life and require replacement. These devices will be replaced with equipment to current day standards offering compatibility with NPE's SCADA and WiMAX based systems, further enabling smart grid initiatives on connected feeders.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **End of Life Assets**

Project #	2017-1007	Reference #	SR-30

I. General Information

Project Title	System Sustainment / Minor Betterments	*Project Number*	2017-1007
Year	2017	*Service Area*	All
Total Capital Cost	$680,000	*Category*	System Renewal

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

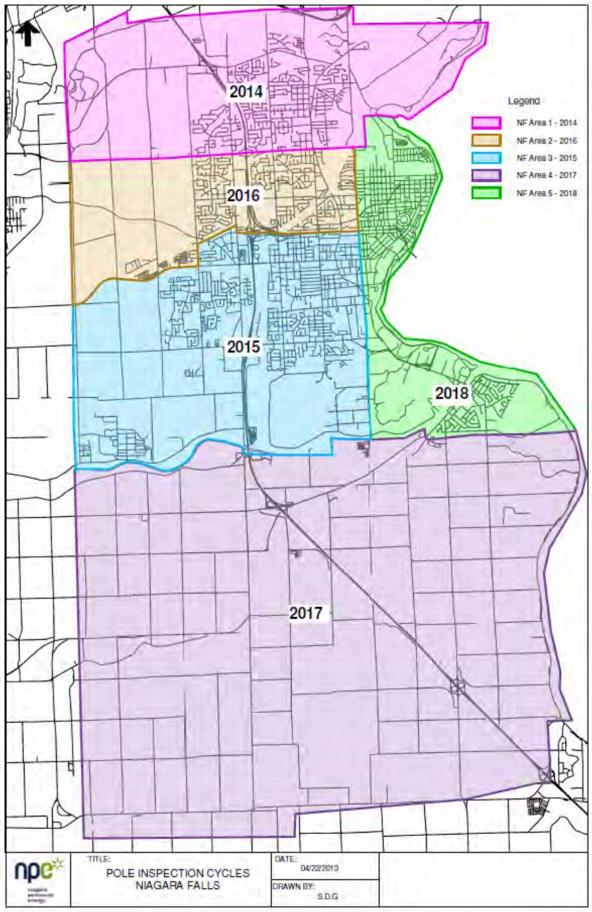
N/A

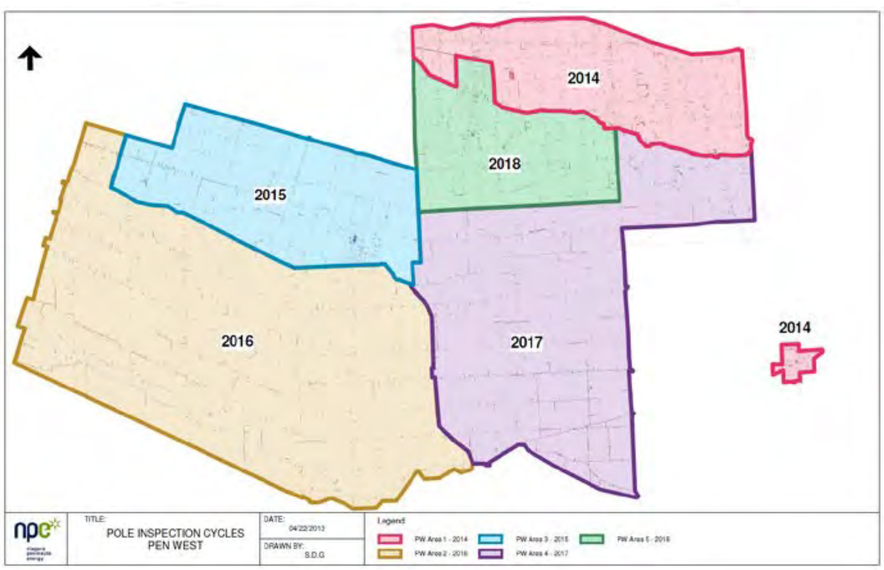
Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2017-1010	Reference #	SR-31
I. General Information			
Project Title	**Pole Replacement Program**	***Project Number***	**2017-1010**
Year	**2017**	***Service Area***	**All**
Total Capital Cost	**$872,112**	***Category***	**System Renewal**
II. Project Description			
Description			
Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The pole is tested for its integrity, a visual inspection is performed of the equipment installed on the pole by qualified Linesmen, the pole is photographed, guy guards are installed & down grounds are repaired/replaced as required, and test results are stored within the Corporate Geographic Information System. The 2017 test area in Niagara Falls is bounded in the West by the Welland City Limits, South to the Fort Erie City Limits, East to the Niagara River, and North to the Welland River. Western Service Territory testing area is from Regional Road #20/#27 to the west, north to Fly Road, East to Victoria Avenue, south to the Boundary line at East Chippawa Road. Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.			

Map Overview





Evaluation Criteria
N/A
Drivers
Sustainment   **Asset Condition Assessment / Poles at End of Life**

Project #	2017-0020	Reference #	SR-32
I. General Information			
Project Title	Kiosk/Submersible Replacement Program	*Project Number*	2017-0020
Year	2017	*Service Area*	All
Total Capital Cost	$841,137	*Category*	System Renewal

II. Project Description

Description

Prior to the advent of pad-mounted Transformer and Switchgear Equipment, supplying loads larger than could be supplied by pole mounted equipment, or areas serviced from underground primary distribution systems, lead to the development of ground mounted masonry enclosures housing high voltage transformation, switching & protection apparatus, and secondary distribution equipment, known as the Kiosk. These block structures were meant to provide Public Safety, but over time, the structures deteriorate and warrant replacement. These are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2013.This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified. xx-Units remain on the 15KV System, and 74-Units remain on the 5KV System. For 2017 the plan is to replace 10 units based on the historical replacement average.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2018-0002	Reference #	SR-83

I. General Information

Project Title	**Pole-mount Step-down Transformer Eliminations**	***Project Number***	**2018-0002**
Year	**2018**	***Service Area***	**Lincoln/West Lincoln**
Total Capital Cost	**$680,859**	***Category***	**System Renewal**

II. Project Description

Description

The former Pen-West Utility Service Territory is largely a Rural Distribution Network originally constructed by Ontario Hydro typically in the 1940's and 1950's. Much of the area is serviced by 8320 Volt Distribution Stations which in turn were sourced from 27.6kV lines. As development became more wide spread, and as Municipal Boundary expansions occurred, Ontario Hydro assets were offloaded to LDC's. Aging Distribution Station Equipment and associated infrastructure, difficulties in providing voltage support due to increasing feeder lengths, and the presence of 27.6KV within the area, favored expansion of the 27.6KV network, with conversion of the 8.32KV system to the higher voltage as warranted. 27.6KV made voltage support easier, feeder lengths were not as critical, and Distribution Stations were no longer required. Station condition determined conversion priority, and projects made more manageable and economically feasible, by pole mounted step down transformer installations to maintain equipment at 8320 Volts where condition of the equipment permitted. However, these assets have also reached end of life, and rebuild/voltage conversion is now required. This program will target the oldest Step-Down installations of the rural distribution line for rebuild, including pole changes, new three-phase and single phase primary & secondary circuits, single and three phase distribution transformer replacements. System benefits include replacement of aging equipment, improved equipment clearance, loss reduction and increased Customer reliability.

Map Overview
N/A
Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity**

Project #	2018-0003	Reference #	SR-75

I. General Information

Project Title	**Subdivision Rehabilitation Phase 2**	***Project Number***	**2018-0003**
Year	**2018**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$490,301**	***Category***	**System Renewal**

II. Project Description

Description

This project is a continuation of the program established in 2017 for residential subdivision rehabilitation. This Capital Program provides a solution to a problem identified during previous Asset Condition Assessments, for replacement of directly buried primary and secondary conductors supplying residential services within the oldest Underground Distribution Residential Subdivisions in the Niagara Falls service territory. The original installations were duct-less, making replacement difficult and costly. To extend lifecycles of the infrastructure NPEI recently completed a Program to replace the Submersible Transformers with Pad-mount Transformers. The program began in 1994 with approx 400 units converted in total. Sections of primary cable within the submersible enclosure, damaged by poor heat dissipation were spliced out and re-terminated, preventing failure. The cable was manufactured to a 133% insulation level, prolonging the life cycle, however, without a base value to compare the results of any cable testing, it is difficult to determine degradation since its installation. Expected lifespan of the cable is 35 years. This program facilitates the installation, by directional boring methods, of a 4" & 3" HDPE conduit on the side of the road where primary and secondary co-exist, and a 4" HDPE conduit where only secondary is installed between all pad-mount foundations. Existing Cable will be "run to failure", at which time new cable would be installed under the Sustainment Budget .

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Replacement of Assets at End Of Life**

Project #	2018-0004	Reference #	SR-84

I. General Information

Project Title	**Mountain Rd Rebuild - Dorchester to St. Paul**	***Project Number***	**2018-0004**
Year	**2018**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$392,227**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 0.95km of urban overhead 13.8kV 3-phase primary line installed in 1966 with 16-new 45' wood poles, constructed in the same alignment as the existing pole line to provide a tie point between the 12-M-1 from Stanley T.S. and the K-M-3 from Kalar M.T.S. Replacement of the undersized primary conductor with 556kcMIL for increased ampacity of the circuit during contingency situations, 5-single phase transformers to replace existing, transfer 4-single phase primary risers, install 0.9km of secondary buss, and transfer of 19 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area with redundancy provisions.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity**

Project #	**2018-0005**	**Reference #**	**SR-85**

I. General Information

Project Title	**Mountain Rd Rebuild - Dorchester to Mewburn**	***Project Number***	**2018-0005**
Year	**2018**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$374,786**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 0.9km of urban overhead 13.8kV 3-phase primary line installed in 1966 with 21-new 45’ wood poles, constructed in the same alignment as the existing pole line which will eventually supply a crossing over the QEW to provide a tie point between the 12-M-1 from Stanley T.S. and the K-M-3 from Kalar M.T.S.. Replacement of the undersized primary conductor with 556kcMIL for increased ampacity of the circuit during contingency situations, 2-single phase transformers to replace existing, transfer 3-single phase primary risers, install 0.5km of secondary buss, and transfer of 6 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area with redundancy provisions.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity**

Project #	2018-0007	Reference #	SR-72
I. General Information			
Project Title	Station 14 Voltage Conversion Phase 2	*Project Number*	2018-0007
Year	2018	*Service Area*	Niagara Falls
Total Capital Cost	$1,359,726	*Category*	System Renewal
II. Project Description			
Description			
See 2017 Project Description			
Map Overview			
See 2017 Map Overview			
Evaluation Criteria			
See 2017 Evaluation Criteria			
Drivers			
See 2017 Drivers			

Project #	2018-0008	Reference #	SR-86

I. General Information

Project Title	**Sinnicks Ave Rebuild - Thorold Stone to Swayze Drive**	***Project Number***	**2018-0008**
Year	**2018**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$1,035,102**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 1.2km of urban overhead double circuit 4.16kV circuits installed in 1949 with a single circuit 13.8kV 3-phase primary line using 34-new 45' wood poles, constructed in the same alignment as the existing pole line to provide a tie point between the 12-M-43 and the 12-M-5 from Stanley T.S. The side streets supplied off the existing double circuit have been previously rebuilt to 15kV class utilizing dual voltage transformers including Keith St (72), part of Coholan St (31), Vine St (66), Harold St (18), Brooks St (29), Frances St (25), Carman St (36), Atlas St (34), Judith St (4) which would be converted to 15KV upon completion of the rebuild at a total customer count of 315. Replacement of 8-single phase & 2-three phase transformers to replace existing, transfer 2-single phase and 1-three phase primary riser, install 1.3km of secondary buss, and direct transfer of 74 residential services to the new buss, re-set 21 existing single phase pole-mount transformers from 2.4KV to 8.0KV. 150 meters of new concrete encased duct-bank from Swayze Dr to Sinnicks Ave for the 600Amp supply from the 12-M-43, and 130 meters of cable replacement from Stn #174 to Sinnicks Ave for 600Amp supply from the 12-M-5. Benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area with redundancy provisions.

Map Overview

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Replacement of Assets at End Of Life**
- **Capacity**
- **Loss Reduction**

Project #	2018-0009	Reference #	SR-87

I. General Information

Project Title	**Cherryhill Dr./Cherrygrove Rd. Rebuild**	*Project Number*	**2018-0009**
Year	**2018**	*Service Area*	**Niagara Falls**
Total Capital Cost	**$501,819**	*Category*	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 1.1 km of urban overhead single phase 2.4kV circuit installed in 1962 with a single phase 8.0kV primary line using 31-new 40' wood poles, constructed in the same alignment as the existing pole line. The streets including Randy Dr (24), Dovewwod Dr (7), Cherrygrove Dr (16), Pinedale Dr (19), Cherryhill Dr (21), for a total of 87 Customers which would be converted to 15kV upon completion of the rebuild. Replacement of 8-single phase transformers to replace existing, install 1.1km of secondary buss, and direct transfer of 87 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity** • **Loss Reduction**

Project #	2018-1007	Reference #	SR-30

I. General Information

Project Title	System Sustainment / Minor Betterments	*Project Number*	2018-1007
Year	2018	*Service Area*	All
Total Capital Cost	$680,000	*Category*	System Renewal

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

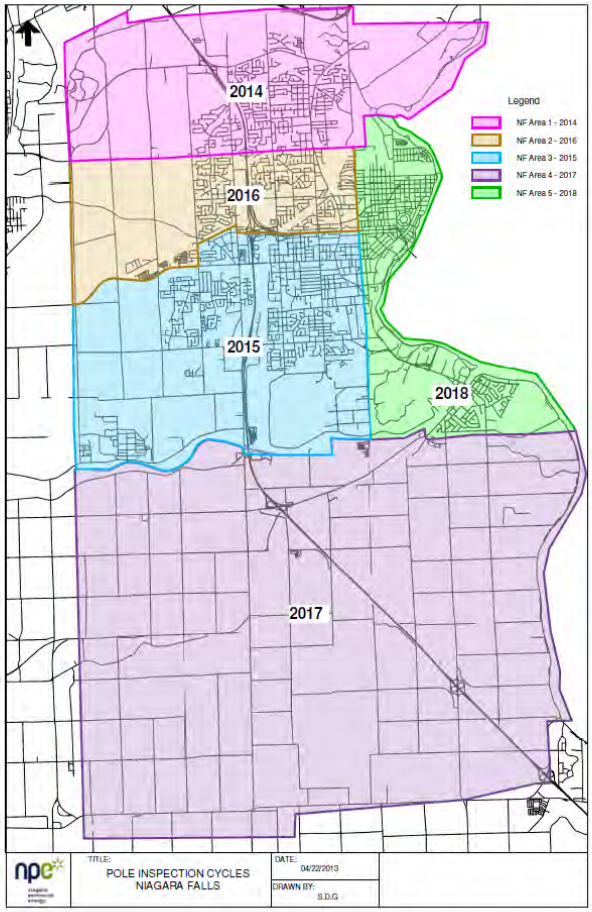
N/A

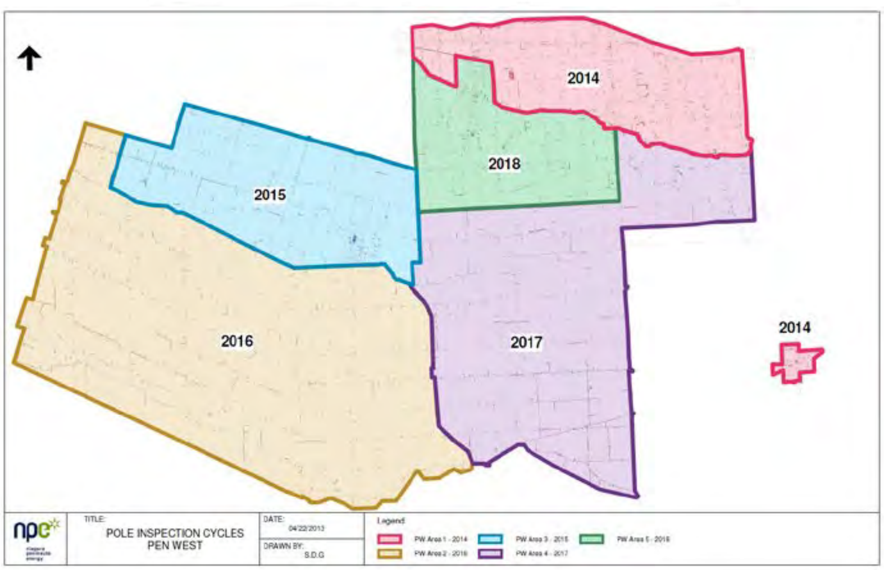
Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	**2018-1010**	**Reference #**	**SR-31**
I. General Information			
Project Title	**Pole Replacement Program**	***Project Number***	**2018-1010**
Year	**2018**	***Service Area***	**All**
Total Capital Cost	**$872,112**	***Category***	**System Renewal**
II. Project Description			
Description			
Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The pole is tested for its integrity, a visual inspection is performed of the equipment installed on the pole by qualified Linesmen, the pole is photographed, guy guards are installed & down grounds are repaired/replaced as required, and test results are stored within the Corporate Geographic Information System. The 2018 Niagara Falls test area is bounded in the West by Stanley Avenue, South to Chippawa Parkway/Weinbrenner Rd., East to the Niagara River, and North to Whirlpool Road. In the Western Service Territory the testing area is bounded by Reg Rd #24-Victoria Ave to the East, north to King Street including Beamsville, South to Young Street, and West to Thirty Road. Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.			

Map Overview





Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment / Poles at End of Life**

Project #	2018-0020	Reference #	SR-32

I. General Information

Project Title	**Kiosk/Submersible Replacement Program**	***Project Number***	**2018-0020**
Year	**2018**	***Service Area***	**All**
Total Capital Cost	**$841,137**	***Category***	**System Renewal**

II. Project Description

Description

Prior to the advent of pad-mounted Transformer and Switchgear Equipment, supplying loads larger than could be supplied by pole mounted equipment, or areas serviced from underground primary distribution systems, lead to the development of ground mounted masonry enclosures housing high voltage transformation, switching & protection apparatus, and secondary distribution equipment, known as the Kiosk. These block structures were meant to provide Public Safety, but over time, the structures deteriorate and warrant replacement. These are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2013.This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified. xx-Units remain on the 15KV System, and 74-Units remain on the 5KV System. For 2018 the plan is to replace 10 units based on the historical replacement average.

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Asset Condition Assessment /Equipment at End of Life**

Project #	2019-0001	Reference #	SR-87

I. General Information

Project Title	**King St. Bartlett to Cherry Ave. Rebuild Phase 1**	***Project Number***	**2019-0001**
Year	**2019**	***Service Area***	**Lincoln**
Total Capital Cost	**$358,212**	***Category***	**System Renewal**

II. Project Description

Description

The Project Scope involves the rebuild of existing double circuit 3-phase 27.6kV and 8.32 kV primary line on King St in place, for approx 1.0km from Bartlett Rd going East to Sann Road. Construction involves the installation of 18-new 50' poles for double circuit, transfer of existing primary cable on the 8.32kV, and installation of 1.0km of new 556kcMIL primary & 3/0 Neutral conductor. The Project is being initiated to provide a capacity increase on the 27.6kV tie between Vineland Station F1 and Beamsville Station 18-M-1 and replace end of life equipment identified through the pole testing program. Benefits include improved supply reliability and flexibility on the system during contingencies and system configuration.

Map Overview

Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life**

Project #	2019-0002	Reference #	SR-83

I. General Information

Project Title	**Pole-mount Step-down Transformer Eliminations**	*Project Number*	**2019-0002**
Year	**2019**	*Service Area*	**Lincoln/West Lincoln**
Total Capital Cost	**$664,244**	*Category*	**System Renewal**

II. Project Description

Description

This is the second phase of a program started in 2018 for pole-mount step-down transformer elimination. The former Pen-West Utility Service Territory is largely a Rural Distribution Network originally constructed by Ontario Hydro typically in the 1940's and 1950's. Much of the area is serviced by 8320 Volt Distribution Stations which in turn were sourced from 27.6kV lines. As development became more wide spread, and as Municipal Boundary expansions occurred, Ontario Hydro assets were offloaded to LDC's. Aging Distribution Station Equipment and associated infrastructure, difficulties in providing voltage support due to increasing feeder lengths, and the presence of 27.6KV within the area, favored expansion of the 27.6KV network, with conversion of the 8.32KV system to the higher voltage as warranted. 27.6KV made voltage support easier, feeder lengths were not as critical, and Distribution Stations were no longer required. Station condition determined conversion priority, and projects made more manageable and economically feasible, by pole mounted step down transformer installations to maintain equipment at 8320 Volts where condition of the equipment permitted. However, these assets have also reached end of life, and rebuild/voltage conversion is now required. This program will target the oldest Step-Down installations of the rural distribution line for rebuild, including pole changes, new three-phase and single phase primary & secondary circuits, single and three phase distribution transformer replacements. System benefits include replacement of aging equipment, improved equipment clearance, loss reduction and increased Customer reliability.

Map Overview
N/A
Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity**

Project #	2019-0003	Reference #	SR-75

I. General Information

Project Title	**Subdivision Rehabilitation Phase 3**	***Project Number***	**2019-0003**
Year	**2019**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$490,301**	***Category***	**System Renewal**

II. Project Description

Description

This project is a continuation of the program established in 2017 for residential subdivision rehabilitation. This Capital Program provides a solution to a problem identified during previous Asset Condition Assessments, for replacement of directly buried primary and secondary conductors supplying residential services within the oldest Underground Distribution Residential Subdivisions in the Niagara Falls service territory. The original installations were duct-less, making replacement difficult and costly. To extend lifecycles of the infrastructure NPEI recently completed a Program to replace the Submersible Transformers with Pad-mount Transformers. The program began in 1994 with approx 400 units converted in total. Sections of primary cable within the submersible enclosure, damaged by poor heat dissipation were spliced out and re-terminated, preventing failure. The cable was manufactured to a 133% insulation level, prolonging the life cycle, however, without a base value to compare the results of any cable testing, it is difficult to determine degradation since its installation. Expected lifespan of the cable is 35 years. This program facilitates the installation, by directional boring methods, of a 4" & 3" HDPE conduit on the side of the road where primary and secondary co-exist, and a 4" HDPE conduit where only secondary is installed between all pad-mount foundations. Existing Cable will be "run to failure", at which time new cable would be installed under the Sustainment Budget .

Map Overview

N/A

Evaluation Criteria

N/A

Drivers

- **Sustainment**
- **Replacement of Assets at End Of Life**

Project #	2019-0004	Reference #	SR-88

I. General Information

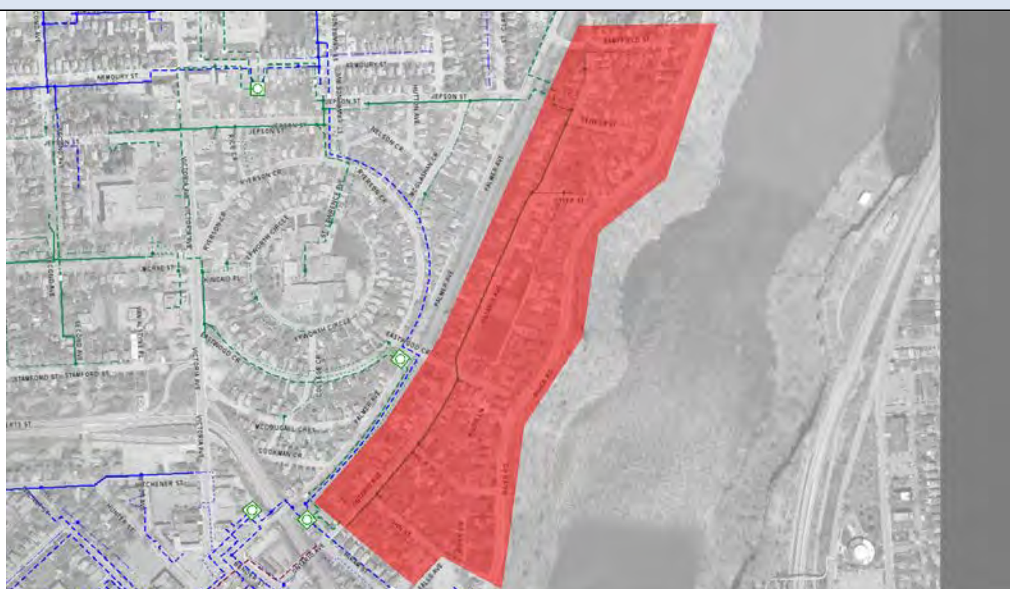
Project Title	**Ontario Ave. Side Street Rebuild and Conversion**	***Project Number***	**2019-0004**
Year	**2019**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$557,132**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 1.12 km of urban overhead single phase 2.4kV circuit installed in 1971 with a single phase 8.0kV primary line using 36-new 40' wood poles, constructed in the same alignment as the existing pole line. The streets including Bampfield Ave(17), Seneca St(18),Otter St (14),River Lane (21), Eastwood Cr (10), Philip St (15), John St (20) for a total of 115 Customers which would be converted to 15kV upon completion of the rebuild. Replacement of 8-single phase transformers to replace existing, install 1.12km of secondary buss, and direct transfer of 115 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area.

Map Overview



Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Replacement of Assets at End Of Life** • **Capacity** • **Loss Reduction**

Project #	2019-0005	Reference #	SR-89

I. General Information

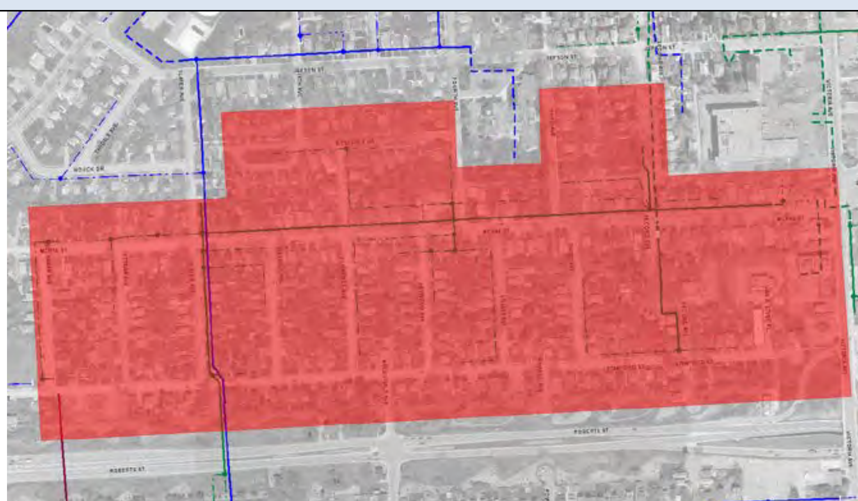
Project Title	**McRae Street Area Rebuild**	***Project Number***	**2019-0005**
Year	**2019**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$1,524,721**	***Category***	**System Renewal**

II. Project Description

Description

Project scope involves the replacement of 0.75km of three phase and 2.25km of single phase urban overhead 4.16kV circuit installed in 1960 with 15kV insulated primary line and dual voltage transformers using 25-new 45' and 60-new 40' wood poles, constructed in the same alignment as the existing pole line. The streets including Second Ave(12), Third Ave (25),Stuart Ave (14), Fourth Ave (9), Heywood Ave (18), Florence (21), Detroit Ave (15) Ottawa Ave (14) Buchanan Ave (13) Stamford St (92) McRae St (112) Rosedale Dr (36) or a total of 381 Customers which will be converted to 15kV at a future date. Replacement of 26-single phase transformers to replace existing, install 3.00 kM of secondary buss, transfer 2-single phase & 2-three phase primary risers, and direct transfer of 465 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.

Map Overview



Evaluation Criteria
N/A
Drivers
Sustainment   **Replacement of Assets at End Of Life**   **Capacity**   **Loss Reduction**

Project #	2019-0007	Reference #	SR-72
I. General Information			
Project Title	Station 14 Voltage Conversion Phase 3 (Final Phase)	*Project Number*	2019-0007
Year	2019	*Service Area*	Niagara Falls
Total Capital Cost	$1,162,570	*Category*	System Renewal
II. Project Description			
Description			
See 2017 Project Description			
Map Overview			
See 2017 Map Overview			
Evaluation Criteria			
See 2017 Evaluation Criteria			
Drivers			
See 2017 Drivers			

Project #	2019-1007	Reference #	SR-30
I. General Information			
Project Title	System Sustainment / Minor Betterments	*Project Number*	2019-1007
Year	2019	*Service Area*	All
Total Capital Cost	$680,000	*Category*	System Renewal

II. Project Description

Description

Betterments consist of minor capital work initiated by unexpected failures of overhead and underground distribution facilities is provided in the annual budget. Unplanned underground cable replacements due to repeated failure is the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also accounted for within this project.

Map Overview

N/A

Evaluation Criteria

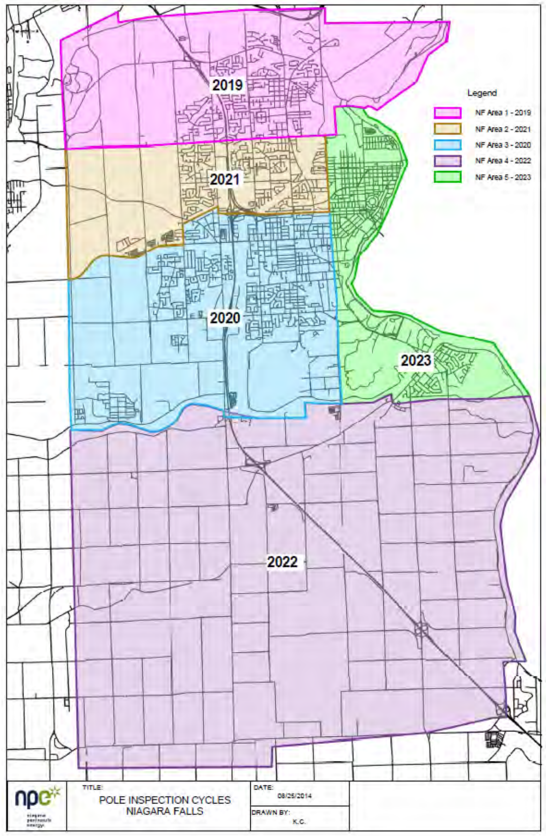
N/A

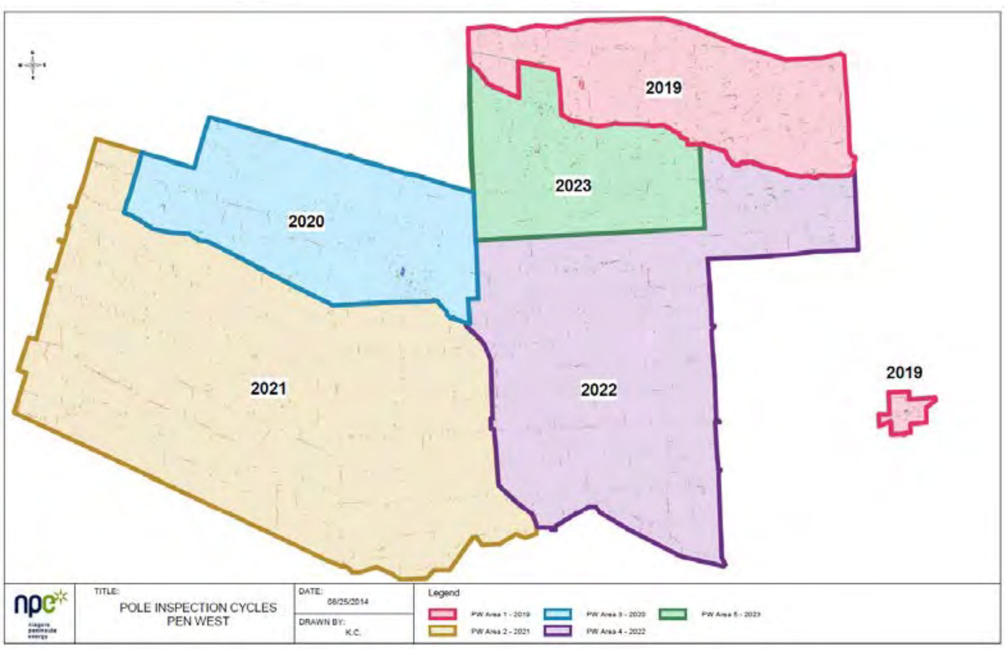
Drivers

- **Sustainment**
- **Unplanned failure of cables / equipment**

Project #	2019-1010	Reference #	SR-31
I. General Information			
Project Title	**Pole Replacement Program**	***Project Number***	**2019-1010**
Year	**2019**	***Service Area***	**All**
Total Capital Cost	**$872,112**	***Category***	**System Renewal**
II. Project Description			
Description			
Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process addressed by replacing subject poles through this program. The pole is tested for its integrity, a visual inspection is performed of the equipment installed on the pole by qualified Linesmen, the pole is photographed, guy guards are installed & down grounds are repaired/replaced as required, and test results are stored within the Corporate Geographic Information System. The 2019 Niagara test area is bounded in the South by Thorold Stone Road, West to Thorold Town Line, North to Mountain Road, and East to Stanley Ave/Whirlpool Road. The Westerns service territory testing area is bounded by Lake Ontario to the North, south to King Street excluding Beamsville, East to Ninth Street, and West to Thirty Road. Suspect poles stemming from prior inspection cycles will be changed year under the program. Poles identified as "replace immediate" are prioritized for change out based on risk assessment criteria.			

Map Overview





Evaluation Criteria
N/A
Drivers
• **Sustainment** • **Asset Condition Assessment / Poles at End of Life**

Project #	2019-0020	Reference #	SR-32
I. General Information			
Project Title	**Kiosk/Submersible Replacement Program**	***Project Number***	**2019-0020**
Year	**2019**	***Service Area***	**All**
Total Capital Cost	**$841,137**	***Category***	**System Renewal**
II. Project Description			
Description			
Prior to the advent of pad-mounted Transformer and Switchgear Equipment, supplying loads larger than could be supplied by pole mounted equipment, or areas serviced from underground primary distribution systems, lead to the development of ground mounted masonry enclosures housing high voltage transformation, switching & protection apparatus, and secondary distribution equipment, known as the Kiosk. These block structures were meant to provide Public Safety, but over time, the structures deteriorate and warrant replacement. These are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2018.This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified. xx-Units remain on the 15KV System, and 74-Units remain on the 5KV System. For 2019 the plan is to replace 10 units based on the historical replacement average.			
Map Overview			
N/A			
Evaluation Criteria			
N/A			
Drivers			
• **Sustainment** • **Asset Condition Assessment /Equipment at End of Life**			

System Service

Project #	2015-0006	Reference #	SS-34
I. General Information			
Project Title	Switchgear Replacement Program	*Project Number*	2015-0006
Year	2015	*Service Area*	All
Total Capital Cost	$250,002	*Category*	System Service
II. Project Description			

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:
Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:
The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:
Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2015-0018	Reference #	SS-53

I. General Information

Project Title	King Street - 27.6kV Extension to Martin Road - Carry Over	*Project Number*	2015-0018
Year	2015	*Service Area*	Lincoln
Total Capital Cost	$114,460	*Category*	System Service

II. Project Description

Description

See 2014 Project Description

Map Overview

See 2014 Project Description

Evaluation Criteria

See 2014 Evaluation Criteria

Drivers

See 2014 Drivers

Project #	2015-SG	Reference #	SS-61

I. General Information

Project Title	Grid Modernization Program	*Project Number*	2015-SG
Year	2015	*Service Area*	All
Total Capital Cost	$215,000	*Category*	System Service

II. Project Description

Description

This is the fourth phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX cable devies (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.

Efficiency:
Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.

Safety:
With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides

visibility of station and system status at all times. **Community Relations / Regulatory:** Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.
Drivers
• **Reliability** • **Safety** • **Efficiency** • **Regulatory**

Project #	2016-0005	Reference #	SS-67

I. General Information

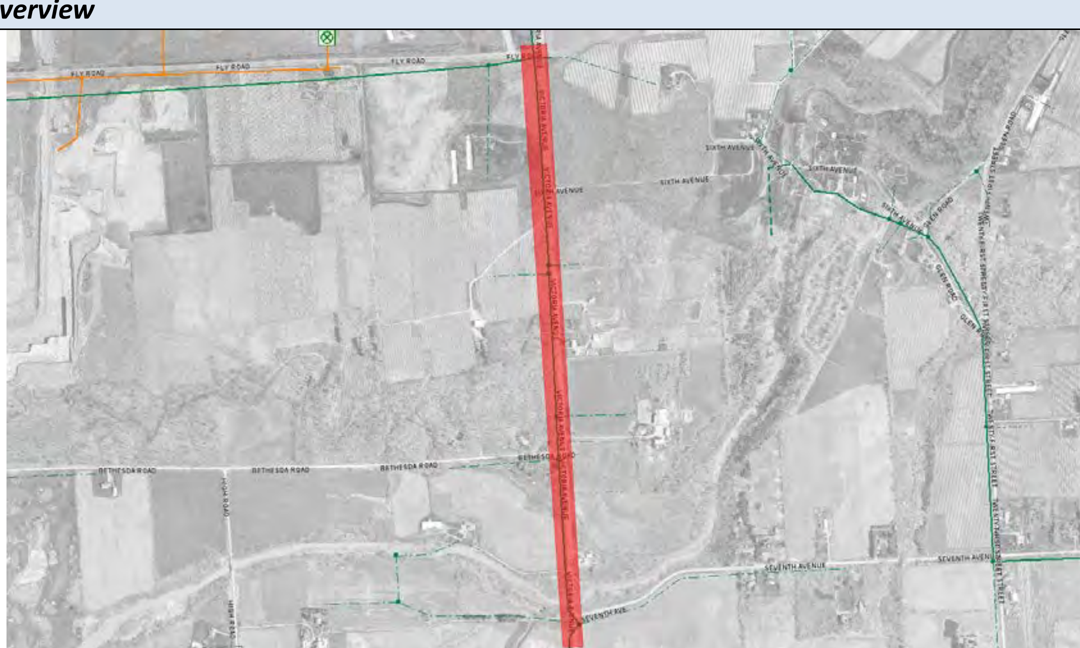
Project Title	**Victoria Ave. South of Fly Rd. Phase 1**	***Project Number***	**2016-0005**
Year	**2016**	***Service Area***	**Lincoln**
Total Capital Cost	**$391,241**	***Category***	**System Service**

II. Project Description

Description

The Project Scope involves the overbuild of an existing 3-phase 8.2 KV primary line on Victoria Ave in place, and constructed with a 3-phase 27.6KV top circuit for approx 2.0 km. Construction involves the installation of 32-new 45' poles, transfer of existing primary cable, and installation of 2.0km of new 556kcMIL Primary and Neutral conductor from Fly Rd South to Seventh Ave. The Project is being initiated to provide a 27.6KV tie to town of Jordan Station. Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration by tying the F-1 Feeder from Vineland D.S to the M-5 Feeder from NWMTS.

Map Overview



Evaluation Criteria
Reliability/Performance: Extension of the 27.6kV circuit on Victoria Ave. provides a second back-up source to Vineland F1 loads east of Vineland in Lincoln. This area is currently fed from a radial supply which traverses a large section of off-road land which is relatively inaccessible. **Efficiency:** The primary line extension provides an alternate supply to the area accessible along a road allowance. This leads to improved restoration times for downstream customers. **Safety:** New construction includes the installation of 55' poles with increased point of attachment to current standards. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency**

Project #	2016-0006	Reference #	SS-34

I. General Information

Project Title	Switchgear Replacement Program	*Project Number*	2016-0006
Year	2016	*Service Area*	All
Total Capital Cost	$250,002	*Category*	System Service

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:
Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:
The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:
Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
Reliability   **Safety**   **Efficiency**

Project #	2016-0007	Reference #	SS-68

I. General Information

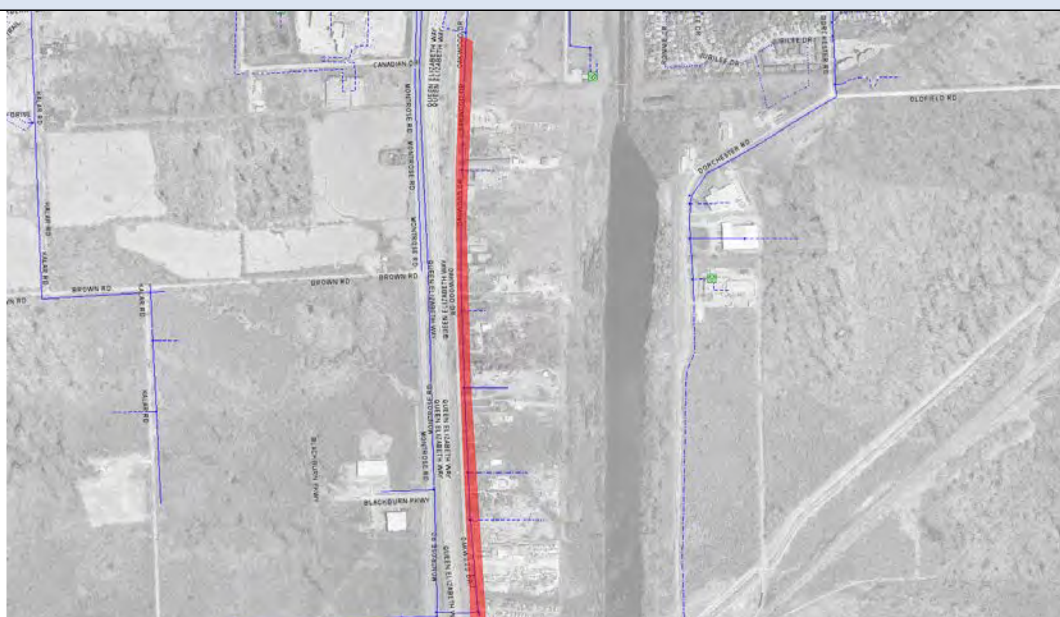
Project Title	Oakwood Drive South of Smart Centers to the QEW Crossing	*Project Number*	2016-0007
Year	2016	*Service Area*	Niagara Falls
Total Capital Cost	$748,101	*Category*	System Service

II. Project Description

Description

Project scope involves replacement of 1.5km of an urban overhead primary distribution line with an overhead 15kV 600 amp class main 3-phase line in the same alignment as the existing. Installation of 25-new 50' wood poles, 7-Single Phase, 2-Three Phase transformers, transfer 3-three phase & 1-Single Phase Underground Primary Riser, and transfer of 24-existing Residential triplex services. Since the original install this section of line has changed function from a radial feed, and has been incorporated into a tie between 2-Transformer Stations, without re-conductoring to facilitate the ampacity increase. System benefits include the replacement of aging equipment originally installed in 1970, system loss reduction, improved reliability, and capacity increase.

Map Overview



Evaluation Criteria
Reliability/Performance: The introduction of a main feeder on Oakwood drive provides an additional Kalar TS - Murray TS feeder tie providing additional back-feed capability for the surrounding area. This will ultimately improve restoration time for connected customers during contingencies. **Efficiency:** The existing supply down Oakwood Drive consists of small overhead copper conductor. Replacement with larger capacity conductor will result in overall loss reduction on the distribution system. **Safety:** New construction includes the installation of 50' poles with increased point of attachment to current standards. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency** • **Loss Reduction**

Project #	2016-0009	Reference #	SS-69

I. General Information

Project Title	**Glenholm to Franklin Ave. - 600kcMIL Underground Install**	***Project Number***	**2016-0009**
Year	**2016**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$153,126**	***Category***	**System Service**

II. Project Description

Description

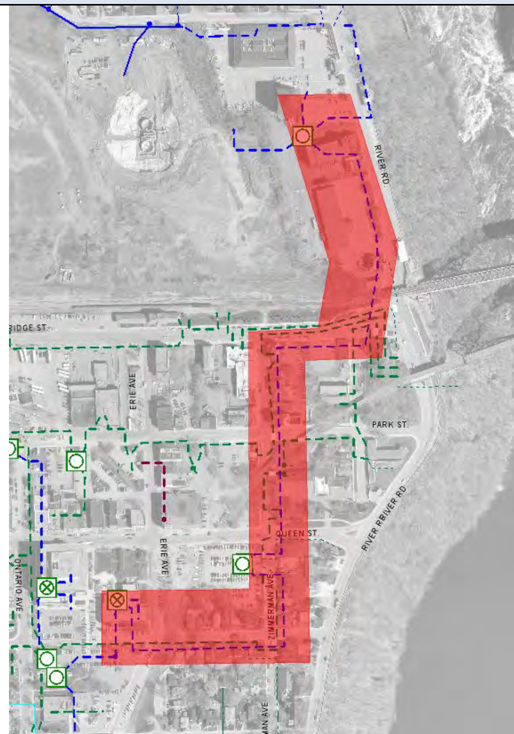
Project scope involves the installation of 150 meters of 600kcMIL Underground 15kV primary cable to complete an intertie between two recently completed system rebuild/upgrades. Installation of 100 meters of new concrete encased duct bank tied into 50 meters of existing duct bank, install 160 meters x 3 of 600kcMIL underground primary cable and completion of 2-primary risers. System benefits include increased flexibility during failure contingency periods, and the ability to reconfigure the system based on the results of optimization studies using system modeling software.

Map Overview

Evaluation Criteria
Reliability/Performance: A new feeder tie between Murray 3M51 and 3M54 provides redundant supply for connected commercial and residential loads in the area. **Efficiency:** Addition of this feeder tie will allow for an improvement in feeder load balancing resulting in a reduction of distribution system losses. **Safety:** The project scope includes the addition of sectionalizing devices which enhance NPEI's ability to sectionalize the system under fault conditions. **Community Relations:** The additional feeder tie improves security of the electrical distribution system in the area.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency** • **Loss Reduction**

Project #	2016-0010	Reference #	SS-70
I. General Information			
Project Title	Downtown Core PILCDSTA De-Commissioning	*Project Number*	2016-0010
Year	2016	*Service Area*	Niagara Falls
Total Capital Cost	$918,758	*Category*	System Service
II. Project Description			
Description			
NPEI has targeted lead jacketed primary cable for removal from service, due to age (installed in 1959), performance, and difficulty of performing repairs. The last section in service, is located between Station #151 on River Rd and the City Hall Sub-Station located on Huron St. Project scope involves the decommissioning of 1.0km of existing 500kcMIL PILCDSTA direct-buried cable by replacement with a combination of new & existing infrastructure. 350 meters of new primary duct bank will be installed on River Rd. between Buttrey St. & Bridge St., and a voltage conversion of an existing underground 4.16kV (F-64) primary line installed in 1995 from the City Hall station to the corner of Bridge Street & River Road. This 2/0 circuit, installed within a concrete encased duct bank takes a similar route to the lead cable, and can be incorporated into the 15kV system by performing a voltage conversion and tying the 2-systems together at City Hall, and at Bridge St. This is feasible since the existing 4.16KV Feeder cable is insulated to 15KV and connected transformers are dual voltage units. System benefits include replacement of infrastructure targeted for decommissioning, the immediate voltage conversion of approx. 500kVA of connected load from Station #6, improved system losses and performance.			

Map Overview



Evaluation Criteria

Reliability/Performance:
Elimination of lead cable at end of life and conversion of connected loads to the 13.8kV system improves reliability in the area.

Efficiency:
The reduction of load from Park Street Station #6 results in an reduction in distribution system losses. Restoration times during contingency are improved with the removal of lead cable from the system.

Safety:
Switchgear and cable at end of life will be removed from the system reducing exposure to electrical faults.

Community Relations:
The scope of the project includes the removal of switchgear at end of life which improves overall aesthetics in the area.

Drivers

- **Reliability**
- **Capacity**
- **Safety**
- **Efficiency**
- **Loss Reduction**

Project #	2016-0011	Reference #	SS-71

I. General Information

Project Title	**Dorchester Road Rebuild - Mountain Road to Riall Street**	***Project Number***	**2016-0011**
Year	**2016**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$780,440**	***Category***	**System Service**

II. Project Description

Description

Project scope involves the replacement of 1.0km of urban overhead 13.8kV primary line installed in 1952 with 20-new 45' wood poles, constructed in the same alignment as the existing pole line, install of 200 meters of concrete encased duct-bank under a major Transmission Corridor due to clearance issues with the transmission line to an overhead line. Replacement of the undersized primary conductor with 556kcMIL for increased ampacity of the circuit during contingency situations, 4-single phase transformers to replace existing, install 0.6km of secondary buss, and transfer of 40 services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement and capacity increase of the supply in the area.

Map Overview

Evaluation Criteria
Reliability/Performance: A main feeder tie between Stanley TS 12M1 and 12M33 provides redundant supply for connected loads in the area. **Efficiency:** Addition of this feeder tie will allow for an improvement in feeder load balancing resulting in a reduction of distribution system losses. **Safety:** Replacement of poles and conductor at end of life reduces the possibility of structural failure and improves overall safety to public and workers in the area. **Community Relations:** Replacement of deteriorated legacy facilities with improved appearance construction, improves overall aesthetics in the area.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency** • **Loss Reduction**

Project #	2016-SG	Reference #	SS-61

I. General Information

Project Title	Grid Modernization Program	*Project Number*	2016-SG
Year	2016	*Service Area*	All
Total Capital Cost	$250,000	*Category*	System Service

II. Project Description

Description

This is the fourth phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX cable devies (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.
Efficiency:
Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.
Safety:
With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides

visibility of station and system status at all times. **Community Relations / Regulatory:** Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.
Drivers
• **Reliability** • **Safety** • **Efficiency** • **Regulatory**

Project #	2017-0005	Reference #	SS-67

I. General Information

Project Title	Victoria Ave. South of Fly Rd. Phase 2	*Project Number*	2017-0005
Year	2017	*Service Area*	Lincoln
Total Capital Cost	$705,385	*Category*	System Service

II. Project Description

Description

The Project Scope involves the rebuild of existing 3-phase 8.32kV primary line on Victoria Ave in place, and constructed to 3-phase 27.6kV for approx 2.0 KM from Fly Rd going South. Construction involves the installation of 32-new 45' poles, transfer of existing primary conductor, and installation of 2.0km of new neutral conductor on Seventh Avenue from the Victoria Avenue to Nineteenth St. The Project is being initiated to provide a 27.6kV tie between Vineland Station F-1 to the M-5 from MWMTS Station Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

Map Overview

Evaluation Criteria
Reliability/Performance: Extension of the 27.6kV circuit from Victoria Ave. provides a second back-up source to Vineland F1 loads east of Vineland in Lincoln. This area is currently fed from a radial supply which traverses a large section of off-road land which is relatively inaccessible. **Efficiency:** The primary line extension provides an alternate supply to the area accessible along a road allowance. This leads to improved restoration times for downstream customers. **Safety:** New construction includes the installation of 45' poles with increased point of attachment to current standards. These attributes increase public and worker safety by reducing the possibility of structure failure and electrical contact. **Community Relations:** Removal of deteriorated poles and replacement with improved appearance construction improves overall aesthetics of NPEI plant.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency**

Project #	2017-0006	Reference #	SS-34

I. General Information

Project Title	Switchgear Replacement Program	*Project Number*	2017-0006
Year	2017	*Service Area*	All
Total Capital Cost	$250,002	*Category*	System Service

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:
Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:
The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:
Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2017-0010	Reference #	SS-79

I. General Information

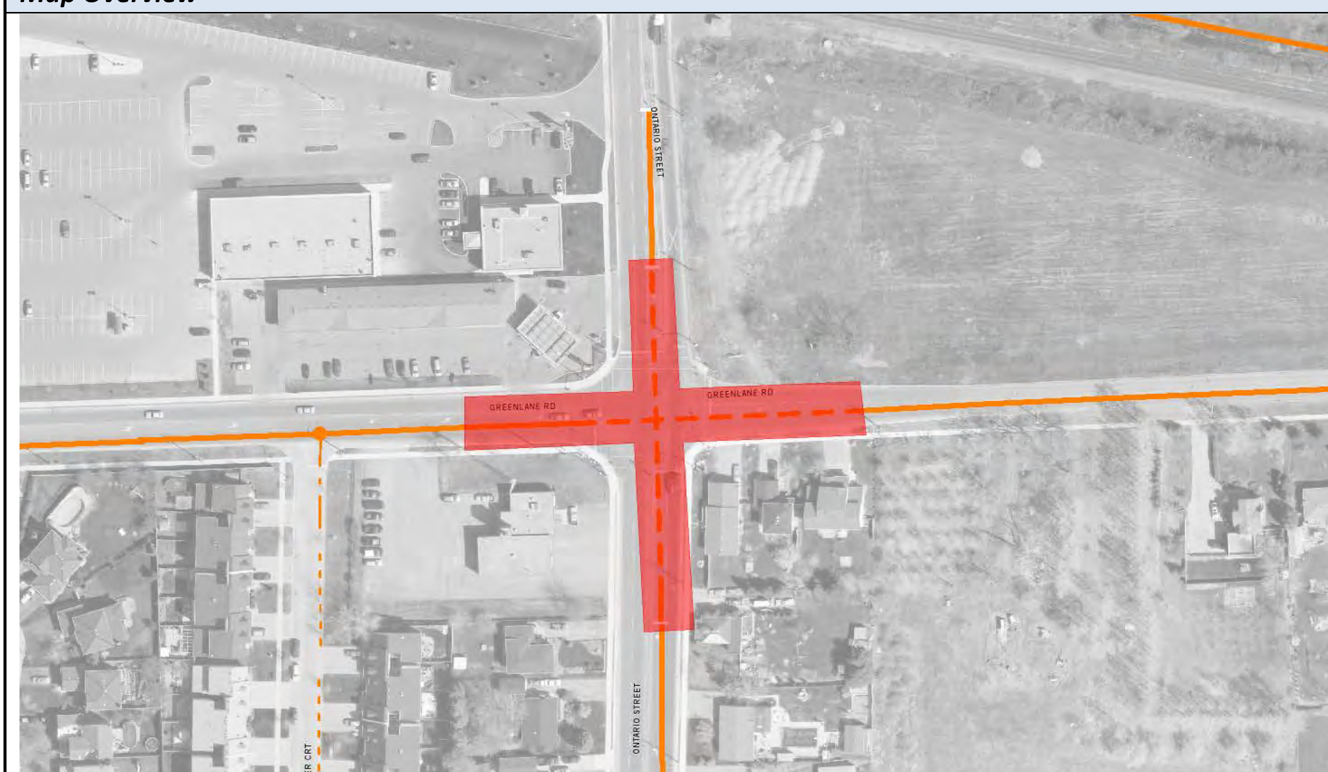
Project Title	Greenlane Road at Ontario Street Tie Point	*Project Number*	2017-0010
Year	2017	*Service Area*	Lincoln
Total Capital Cost	$163,445	*Category*	System Service

II. Project Description

Description

Project scope involves the installation of approx 0.25km of 1000kcMIL underground primary cable in a new concrete encased duct-bank to create a tie on the Beamsville 18-M-1 system between two primary lines on Ontario Street & Greenlane Rd. Benefits include increased Customer reliability during contingencies and capacity increase to the Beamsville downtown core.

Map Overview



Evaluation Criteria
Reliability/Performance: Creation of an additional tie on the 18M1 circuit provides a back-up source to for customers in the surrounding area. Currently, customer's North of John Street are fed from a radial supply. **Efficiency:** The additional circuit tie leads to improved restoration times for downstream customers. It also permits additional load balancing on the 18M1 circuit, reducing distribution system losses. **Safety:** The project scope includes the addition of sectionalizing devices which enhance NPEI's ability to sectionalize the system under fault conditions. **Community Relations:** The additional feeder tie improves security of the electrical distribution system in the area.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency** • **Loss Reduction**

Project #	2017-0011	Reference #	SS-80

I. General Information

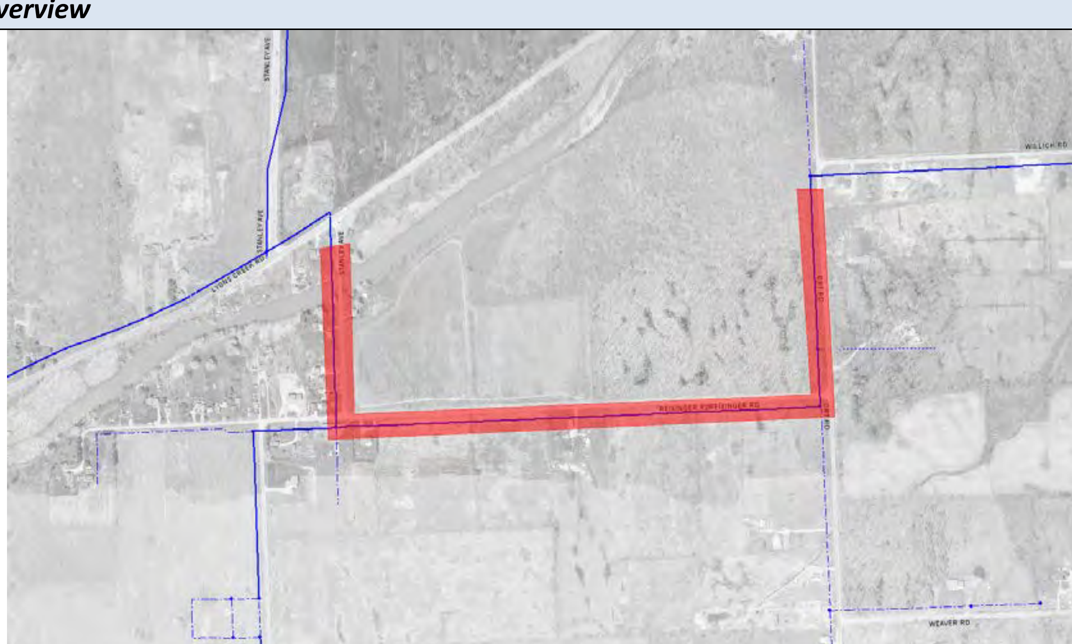
Project Title	**Chippawa - Redundant Supply Upgrades Phase 1**	***Project Number***	**2017-0011**
Year	**2017**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$442,690**	***Category***	**System Service**

II. Project Description

Description

Phase I of the two part Project scope involves rebuild/reinforcement of 1.4km of a existing rural overhead primary distribution line, on Stanley Ave from Lyons Creek Rd to Rexinger Rd, Rexinger Road from Stanley Ave to Ort Rd--Ort Rd from Rexinger Rd to Willick Rd, incorporating 12-new pole installs and salvaging poles upgraded by the Pole Replacement Program. NPEI will re-conductor the existing 1/0 Aluminum Primary with 556kcMIL Aluminum for the required capacity increase. This Project will enable NPEI to target the removal of a sub-standard aerial primary Welland River Crossing feeding into the Village of Chippawa. System benefits include improved reliability, inter-tie capabilities between the 3-M-27 & 3-M-56 Feeders sourced from the Murray T.S.

Map Overview



Evaluation Criteria
Reliability/Performance: A main feeder tie between Murray TS 3M27 and 3M56 provides redundant supply for connected loads in the area. **Efficiency:** Addition of this feeder tie will allow for an improvement in feeder load balancing resulting in a reduction of distribution system losses. **Safety:** This multi-phase project targets removal of a sub-standard aerial structure crossing the Welland River. The structure is at end of life and its elimination from the system improves both public and worker safety. **Community Relations:** Removal of the existing legacy crossing structure will improve overall aesthetics in the area. The additional back-feed to the area improves security of the electrical distribution system.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency** • **Loss Reduction**

Project #	2017-0012	Reference #	SS-81

I. General Information

Project Title	**Brown Road Extension - Montrose to Blackburn Parkway**	***Project Number***	**2017-0012**
Year	**2017**	***Service Area***	**Niagara Falls**
Total Capital Cost	**$231,411**	***Category***	**System Service**

II. Project Description

Description

Project scope involves extension of 1.2km of a urban overhead primary distribution line, overbuilt on a wooden pole line built by Bell Canada in 2008 at which time NPEI had Bell install 13-poles with additional height from 35' to 45' . The framing & stringing of this section of line will be incorporated into a tie between 2-previous line builds to service a new low lift pumping station and an Industrial Subdivision owned by the City of Niagara Falls. System benefits include improved reliability, inter-tie capabilities between the K-M-6 & K-M-2 Feeders sourced from the Kalar M.T.S and the 3-M-30 from Murray T.S.

Map Overview

Evaluation Criteria
Reliability/Performance: Addition of this feeder tie allows back-feed of KM2, KM6, and 3M30 circuits. This provides redundant supply for connected loads in the area. **Efficiency:** Addition of this feeder tie will allow for an improvement in feeder load balancing resulting in a reduction of distribution system losses. **Safety:** The project scope includes the addition of sectionalizing devices which enhance NPEI's ability to sectionalize the system under fault conditions. **Community Relations:** The additional feeder tie improves security of the electrical distribution system in the area.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency** • **Loss Reduction**

Project #	2017-SG	Reference #	SS-61

I. General Information

Project Title	**Grid Modernization Program**	***Project Number***	**2017-SG**
Year	**2017**	***Service Area***	**All**
Total Capital Cost	**$250,000**	***Category***	**System Service**

II. Project Description

Description

This is the fourth phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX cable devies (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:

Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.

Efficiency:

Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.

Safety:

With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides

visibility of station and system status at all times.

Community Relations / Regulatory:

Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.

Drivers

- **Reliability**
- **Safety**
- **Efficiency**
- **Regulatory**

Project #	2018-0006	Reference #	SS-34

I. General Information

Project Title	Switchgear Replacement Program	*Project Number*	2018-0006
Year	2018	*Service Area*	All
Total Capital Cost	$250,002	*Category*	System Service

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:
All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:
Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:
The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:
Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
Reliability   **Safety**   **Efficiency**

Project #	2018-SG	Reference #	SS-61

I. General Information

Project Title	**Grid Modernization Program**	***Project Number***	**2018-SG**
Year	**2018**	***Service Area***	**All**
Total Capital Cost	**$250,000**	***Category***	**System Service**

II. Project Description

Description

This is the fourth phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX cable devies (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:

Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.

Efficiency:

Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.

Safety:

With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides

visibility of station and system status at all times. **Community Relations / Regulatory:** Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.
Drivers
• **Reliability** • **Safety** • **Efficiency** • **Regulatory**

Project #	2019-0006	Reference #	SS-34

I. General Information

Project Title	**Switchgear Replacement Program**	***Project Number***	**2019-0006**
Year	**2019**	***Service Area***	**All**
Total Capital Cost	**$250,002**	***Category***	**System Service**

II. Project Description

Description

Results from the underground equipment inspection program identified switchgear units with one or more deficiencies. NPEI maintains a prioritized list of switchgear due for replacement based results of the Asset Condition Assessment. This project is part of a multi-year program designed to either replace deficient switchgear units. Approximately 4 switchgear units a year are replaced under the program. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:

All switchgear units that have been identified as deficient are of the live front insulated type. NPEI's current standards require a switchgear unit that incorporates a live front design with stainless steel enclosure and components. Elimination of live front components greatly reduces the chance of an electrical fault due to termination degradation or contamination.

Efficiency:

Elimination of legacy switchgear and will reduce the requirement for stock replacements. Incorporation of stainless steel components and dead front design substantially increases the maintenance interval on new units.

Safety:

The live front design of replacement units significantly reduces the electrical shock hazard to workers and the public.

Community Relations:

Replacement of switchgear units that currently have enclosure deterioration improves overall aesthetics of NPEI plant present in the area. The stainless steel design of new enclosures mitigates corrosion issues moving forward.

Drivers
• **Reliability** • **Safety** • **Efficiency**

Project #	2019-0011	Reference #	SS-80
I. General Information			
Project Title	Chippawa - Redundant Supply Upgrades Phase 2	*Project Number*	2019-0011
Year	2019	*Service Area*	Niagara Falls
Total Capital Cost	$561,738	*Category*	System Service
II. Project Description			
Description			
Phase II of the two part Project scope involves rebuild/reinforcement of 1.2km of an existing rural overhead primary distribution line, on Willoughby Drive from Lyons Creek Rd to Willick Rd, incorporating 30-new pole installs and salvaging poles upgraded by the Pole Replacement Program. NPEI will re-conductor the existing 1/0 Aluminum Primary with 556kcMIL Aluminum for the required capacity increase. Replacement of 5-single phase transformers to replace existing, install 1.0 KM of secondary buss, transfer 2-single phase and 2-three phase primary risers, and direct transfer of 25 residential services to the new buss with 30 pole removals upon completion. This Project will enable NPEI to target the removal of a sub-standard aerial primary Welland River Crossing feeding into the Village of Chippawa. System benefits include improved reliability, inter-tie capabilities between the 3-M-27 and 3-M-56 Feeders sourced from the Murray T.S.			
Map Overview			

Evaluation Criteria
Reliability/Performance: A main feeder tie between Murray TS 3M27 and 3M56 provides redundant supply for connected loads in the area. **Efficiency:** Addition of this feeder tie will allow for an improvement in feeder load balancing resulting in a reduction of distribution system losses. **Safety:** This multi-phase project targets removal of a sub-standard aerial structure crossing the Welland River. The structure is at end of life and its elimination from the system improves both public and worker safety. **Community Relations:** Removal of the existing legacy crossing structure will improve overall aesthetics in the area. The additional back-feed to the area improves security of the electrical distribution system.
Drivers
• **Reliability** • **Capacity** • **Safety** • **Efficiency** • **Loss Reduction**

Project #	2019-SG	Reference #	SS-61

I. General Information

Project Title	**Grid Modernization Program**	***Project Number***	**2019-SG**
Year	**2019**	***Service Area***	**All**
Total Capital Cost	**$250,000**	***Category***	**System Service**

II. Project Description

Description

This is the fourth phase of a multi-year project to equip substations in Niagara Peninsula Energy's Western portion of the service territory. The purpose of this project is to introduce a wireless communication network (WiMAX) for connectivity between NPEI's control center and substations. The wireless network will operate in Industry Canada's allocated 1800 MHz frequency space for electric utilities. WiMAX will facilitate SCADA and distributed automation solutions in later phases of implementation. Included in this project is the introduction of WiMAX cable devies (relays, monitors, etc.) into substations in the West Lincoln, Lincoln, and Fonthill areas as substations are being rebuilt. Additionally, the WiMAX project incorporates DC power supply systems in substations that previously had no standby power supplies for redundancy.

Map Overview

N/A

Evaluation Criteria

Reliability/Performance:

Introduction of the WiMAX network in conjunction with IP based IED's in substations will lead to a reduction in response and restoration times during outages. The incorporation of backup DC system into the WiMAX deployment will provide substations with back-up low voltage power and visibility up to 48 hours during loss of supply conditions. The technology will permit distributed automation initiatives once deployment matures in later phases.

Efficiency:

Control center based operation for hold-offs, breaker status change, etc. will significantly reduce and in some cases eliminate drive times during normal construction work and outage response scenarios. End point status and alarms will be incorporated into NPEI's outage management system in later phases of the project to promote the execution of efficient response plans.

Safety:

With the introduction of smart grid based controls into distribution substations and systems, it is paramount that remote visibility be maintained during contingencies. The WiMAX solution provides

visibility of station and system status at all times. **Community Relations / Regulatory:** Implementation of smart grid technologies such as WiMAX are in line with Provincial initiatives to modernize Ontario's electricity system. Automated response and restoration will benefit the security of supply for NPEI's connected customers.
Drivers
• **Reliability** • **Safety** • **Efficiency** • **Regulatory**

General Plant

Project #	2015-2019-General Plant	Reference #	
I. General Information			
Project Title	General Plant	*Project Number*	N/A
Year	2015-2019	*Service Area*	All
Total Capital Cost	$1,447,492 (Annual Average)	*Category*	General Plant
II. Project Description			

Description

The following table is a summary of General Plant capital expenditures annually from 2015 to 2019:

General Plant	Expenditure
Building	$44,000
Computer Hardware	$240,248
Computer Software	$368,740
Vehicles	$698,878
General Equipment	$95,627

2015-2019 Expenditures Include:

Building:

- Additional paving in Niagara Falls. $90K.
- Control room modification in Niagara Falls. $50K.
- New meeting rooms and office in Niagara Falls. $80K.

Computer Hardware:

- New and Replacement Servers. $505K.
- Network Equipment. $102K.
- Barcoding Equipment. $25K.
- Cell Phones. $25K.
- PCs, laptops, notebooks, monitors and printers. $358K.
- Phone System. $149K.
- Other Equipment. $37K.

Computer Software:

- Programming / Professional Fees. $300K.
- Harris Northstar CIS. $150K.
- Workforce/Outage Management. $290K.
- SCADA system. $140K.
- Barcoding software. $100K.
- Oracle Licenses. $80K.
- Fleet vehicle software. $75K.
- Microsoft Dynamics GP. $75K.
- Microsoft Windows / Office licenses. $72K.
- Apollo Workflow. $50K.
- File Nexus. $50K.
- Website improvements. $50K.
- Disaster Recovery. $50K.

Vehicles:

- Pick-up trucks (10). $370K.
- Vans (3). $139K.
- Cube Van (1). $61K.
- Bucket Trucks (5). $1,608K.
- Radial Boom Derricks (2). $892K.
- Backhoe (1). $70K.
- Pole Trailers (2). $44K.
- Go-Devil (1). $135K.
- 500 kVa portable generator (1). $175K.

General Equipment:

- Office furniture. $45K.
- Photocopiers. $36K.
- Control Room workstation and table. $10K.
- Furniture for additional meeting room and 2 offices. $18K.
- Phasing sticks. $13K.
- Hydraulic Drills. $27K.
- Fibre Insulating Cover Ups. $15K.
- Gator Crimping Press. $13K.
- Tools for new line trucks. $37K.
- Miscellaneous general equipment. $55K.
- Miscellaneous replacement tools. $186K.

Map Overview
N/A
Evaluation Criteria
N/A
Drivers
• **Business Operations Efficiency** • **Distribution System Operation Support**

Attachment 2 of 3

OEB Appendix 2-AB

File Number:	EB-2014-0096
Exhibit:	2
Tab:	2
Schedule:	1
Attachment:	2
Date:	29-Aug-14

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2010			2011			2012			2013			2014 Bridge Year			2015 Test Year	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	2,130	2,558	20.1%	2,199	942	-57.2%	1,630	1,086	-33.4%	2,031	1,997	-1.6%	1,731	1,731	0.0%	2,429	2,249	1,821	1,933	1,663
System Renewal	2,998	2,769	-7.6%	4,768	4,162	-12.7%	7,870	5,150	-34.6%	5,838	5,907	1.2%	7,307	7,307	0.0%	6,383	4,161	5,889	7,301	7,223
System Service	6,699	6,465	-3.5%	1,512	1,966	30.0%	2,362	1,424	-39.7%	1,100	847	-23.0%	580	2,483	328.1%	926	3,760	2,449	769	1,330
General Plant	1,820	1,621	-10.9%	1,123	1,280	14.0%	2,769	2,621	-5.4%	6,028	3,897	-35.3%	3,267	3,267	0.0%	1,447	1,434	1,352	1,204	1,311
TOTAL EXPENDITURE	13,647	13,413	-1.7%	9,603	8,350	-13.0%	14,631	10,280	-29.7%	14,997	12,649	-15.7%	12,885	14,788	14.8%	11,185	11,605	11,511	11,207	11,528
System O&M	$ 5,731	$ 5,691	-0.7%	$ 6,142	$ 6,282	2.3%	$ 6,764	$ 6,708	-0.8%	$ 6,880	$ 6,281	-8.7%	$ 6,636	$ 6,636	0.0%	$ 6,846	$ 6,983	$ 7,123	$ 7,265	$ 7,410

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 2014 Actual = the Plan at time of filing 12

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

Attachment 3 of 3

OEB Appendix 2-AA

File Number:	EB-2014-0096
Exhibit:	2
Tab:	2
Schedule:	1
Page:	3
Date:	29-Aug-14

Appendix 2-AA
Capital Projects Table

Project #	Ref #	Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	Total
		Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	
		System Access							
		Subdivisions	682,640	290,295	518,409	703,212	400,000	587,004	3,181,561
	42	Customer Connection/Extension	161,656	389,962	269,890	177,811			999,318
	42	New Upgrade Services	331,699	458,414	196,437	84,734			1,071,284
	43	Line Relocation due to Municipal Requirements < Materiality	472,209	295,727	236,975	355,572	539,910	500,000	2,400,394
	42	Demand based system reinforcements fo	435,393	573,712	711,788	1,011,493	1,410,778	1,007,500	5,150,664
	55	Niagara Parks Commission						818,905	818,905
2013-0100	**38**	City of Niagara Falls Kalar @ Rideau				169,530			169,530
2010-0016	**39**	Dorchester NS&T to Morrison	180,976						180,976
2011-0072	**40**	Drummond & Lundy's Lane Conflicts			267,123				267,123
2010-0009	**41**	Kalar to Catalina relocation	164,362	483,044					647,406
2010-0053		Oakwood Drive relocation	159,399						159,399
2010-0026	**49**	South Pelham Street	816,593						816,593
		Capital contributions	-1,160,428	-1,571,526	-1,472,887	-991,373	-900,000	-827,800	-6,924,015
		Sub-Total System Access	**2,244,499**	**919,629**	**727,734**	**1,510,979**	**1,450,689**	**2,085,609**	**8,939,139**
		Miscellaneous System Access	313,134	22,692	357,824	486,453	280,000	343,500	1,803,603
		Total System Access	**2,557,633**	**942,320**	**1,085,559**	**1,997,432**	**1,730,689**	**2,429,109**	**10,742,741**
		System Renewal							
		MS/DS Rehabilitations							
2010-0025	4	Pelham MS	226,046						226,046
2010-0017	10	Campden DS Feeder Egress	207,208						207,208
2011-0017	12	Campden DS Oil Containment		214,586					214,586
2011-0013	5	Smithville		361,959	274,090				636,049
2011-0022	6	Station Street		41,711	137,209	100,331			279,250
	7	Station #22 North of Pew						507,139	507,139
	8	Station #22 South of Pew						143,724	143,724
2012-0012	6	Greenlane			275,300	197,505			472,805
2013-0017	9	Station #8				191,113	252,037		443,150
2011-0011	11	4 Sectionalizing West Area		156,718					156,718
2011-0004	13	Lundy's Lane Pole Line -Montrose		156,213					156,213
2011-0007	14	Murray/Culp/Dunn/Main Rebuilds		395,970					395,970
2011-0005	15	Riall St Rebuild		143,116	357,948				501,064
2012-0002	16	Lundy's Lane/Ker St UG replacement			356,580				356,580
2012-0001	17	Montrose Kinsmen to Lundys			608,128				608,128
2012-0007	18	Murray/Dixon Rebuild			633,981				633,981
2012-0014	19	Victoria Ave Voltage Conversion			173,042	170,305			343,346
2013-0005	1	12-M-6 Replacement				538,747	372,631		911,378
2013-0011	2	Dorchester-Garden St to McMillan				198,807	362,018		560,825
2013-0008	3	High Street - Dorchester Stn 10 O/H				633,880			633,880
2013-0007	20	Murray/Culp				712,700			712,700
2013-0021	21	OH to UG Beacon Inn Jordan				259,593			259,593
2013-0003	22	UG Primary Weightman Bridge				113,001	701,810		814,811
2014-0009	23	3-M-28, 3-M-26, 3-M-29					417,731		417,731
2014-0001	24	Crawford Street Rebuild					516,557	282,324	798,880
	56	Frederica Street Rebuild						676,144	676,144
2014-0004	25	Fallsview Blvd -Ferry/Robinson					332,173		332,173
2014-0015	26	Jordan Rd-Red Maple to QEW					397,516		397,516
	26	Jordan Phase II						449,324	449,324
2014-1006	27	Wholesale Meter Replacement					300,000		300,000
2014-0008	28	OH to UG Rolling Acres Phase I					768,694	570,500	1,339,194
2014-0007	29	OH line rebuilds - 6 streets					516,513		516,513
1007 & 20(	30	System Sustainment/Minor Betterments	1,008,971	451,575	525,207	670,727	400,000	680,000	3,736,480
1010 & 20	31	Replace poles identified with limited structural integrity	788,664	826,302	862,338	859,298	778,702	431,729	4,547,032
0020's	32	Replacement of Submersibles & Kiosks with EFD switches and posi-tects	501,362	508,036	705,374	643,270	624,457	647,029	3,629,528
2013-2011	33	Replacement of Transformers with >50PPM PCB Content				125,175	566,479	495,104	1,186,758
	57	NWTC Metering						289,605	289,605
	60	Willodell Rebuild						310,710	310,710
	59	Willoughby Dr. Extension						383,293	383,293
	58	Willoughby Drive						372,191	372,191
		Sub-Total System Renewal	**2,732,252**	**3,256,185**	**4,909,196**	**5,414,452**	**7,307,316**	**6,238,817**	**29,858,218**
		Miscellaneous System Renewal	37,016	905,710	240,415	492,575		144,237	1,819,953
		Total System Renewal	**2,769,268**	**4,161,895**	**5,149,611**	**5,907,027**	**7,307,316**	**6,383,054**	**31,678,171**
		System Service							
		Smart meters	4,175,010			27,128	1,903,089		6,105,227
		MIST Meters						143,150	143,150
0006's	**34**	Switchgear replacement program	461,327	191,370	313,737	264,913	110,057	250,002	1,591,405
2010-0024	**35**	Cherry Avenue	179,386						179,386
2010-0023	**36**	Durham Voltage Conversion	364,430						364,430
2010-0002	**37**	High Street Area	255,782						255,782
2010-0008	**47**	Oakwood Drive	198,387						198,387
2011-0003	**50**	KM2 & KM6 Montrose-McLeod		347,760					347,760
2012-0003	**51**	Kalar MTS K-M-1			169,041				169,041
2014-0018	**53**	King Street 27.6 kV					112,554	114,460	227,014

2010-0007	**54**	Robinson St Primary Extension	306,869	733,072					1,039,940
	62	Culp St-Drummond to Main	211,701						
	48	Kalar Extend NS&T ROW-Beaverdams		385,308	383,130				768,438
		Mobile Substation		214,555					214,555
		Wi-Max Project			332,339	348,370	227,500	215,000	1,123,209
		Sub-Total System Service	**6,152,892**	**1,872,065**	**1,198,247**	**640,410**	**2,353,200**	**722,612**	**12,939,426**
		Miscellaneous	312,460	94,319	225,537	206,861	130,000	203,000	1,172,176
		Total System Service	**6,465,352**	**1,966,383**	**1,423,783**	**847,272**	**2,483,200**	**925,612**	**14,111,602**
		General Plant							
		Building	67,188	121,779	631,111	1,912,395	1,500,485	44,000	4,276,958
		Computer Hardware	257,960	247,812	370,710	274,903	297,040	240,248	1,688,673
		Computer Software	250,022	193,505	213,431	114,742	498,710	368,740	1,639,150
		Vehicles	869,037	541,643	1,160,649	1,329,696	672,000	698,878	5,271,903
		General Equipment	176,811	175,156	244,851	265,585	299,000	95,627	1,257,029
		Sub-Total General Plant	**1,621,018**	**1,279,896**	**2,620,751**	**3,897,320**	**3,267,235**	**1,447,492**	**14,133,713**
		Miscellaneous-General Plant	0	0	0	0	0	0	-
		Total General Plant	**1,621,018**	**1,279,896**	**2,620,751**	**3,897,320**	**3,267,235**	**1,447,492**	**14,133,713**
		Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)		0	0	0	0	0	-
		Total	**13,413,271**	**8,350,495**	**10,279,704**	**12,649,050**	**14,788,440**	**11,185,268**	**70,666,228**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Capitalization Policy

NPEI's Capitalization Policy is as follows:

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among existing and future customers. As capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development or betterment of the capital assets should be capitalized. These capitalized costs are allocated over the estimated useful life of the assets by amortization. The Company adopts the full cost accounting in accordance with guidance in the Canadian Institute of Chartered Accountants (CICA) Handbook.

- Asset Cost

  Costs for capital assets installed or erected by the Company include:
  - Direct material.
  - Direct labour.
  - Direct vehicle costs.
  - Indirect costs including overheads for material and labour.
  - Sub-contracting cost, if any.

Definition of cost (extract from CICA Handbook paragraph 3061.05):

Cost is the amount of consideration given up to acquire, construct, develop, or better a capital asset and includes all costs directly attributable to the acquisition, construction, development or betterment of the capital asset including installing it at the location and in the condition necessary for its intended use.

A betterment is a cost which is incurred to enhance the service potential of a capital asset. Expenditures for betterments are capitalized. This enhancement in service potential can include an increase in the physical output or service capacity, decrease in associated operations costs, extension in the useful life of the asset, or improvement in the quality of the asset's output.

Definition of betterment (extract from CICA Handbook paragraph 3061.26):

Cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. The cost incurred in the maintenance of the service potential of a capital asset is a repair, not betterment. If a cost has the attributes of both a repair and a betterment, the portion considered to be a betterment is included in the cost of the asset.

- Asset Recognition

  Property, plant and equipment that meet the definition of a capital asset as provided in the CICA Handbook are capitalized. Expenditures that do not meet the definition are expensed in the current year.

Definition of assets (extract CICA Handbook paragraph 1000.29):

Assets are economic resources controlled by an entity as a result of past transactions or events from which future economic benefits may be obtained. Assets have three essential characteristics:

a) They embody a future benefit that involves a capacity, singularly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and in the case of not-for-profit organizations, to provide services;
b) The entity can control access to the benefit; and
c) The transaction or event giving rise to the entity's right to, or control of, the benefit has already incurred.

In addition, in identifying a benefit there must be:

a) An ability to earn income or supply a service over its useful life;

b) A reasonable expectation that the benefit will be provided in future periods; and
c) The future period must be identifiable and greater than one year.

- Capitalization Threshold

Theoretically, any expenditure that meets the asset cost and asset recognition criteria would be recorded as a capital asset. However, for practical reasons, qualifying costs would only be capitalized if it has a useful life of more than one year; and the item cost is greater than $1,000 for readily identifiable assets or greater than $1,000 for like pooled assets, for example a number office chairs purchased at once. This threshold may be changed at the discretion of the VP Finance. Land will always be capitalized, regardless of cost.

- Spare transformers and meters

Spare transformers and meters are accounted for as capital assets since they form an integral part of the reliability program for a distribution system. They are not intended for resale and cannot be classified as inventory in accordance with CICA Handbook Section 3030.

- Amortization

Amortization is provided on a straight-line basis for capital assets available for use over their estimated service lives, at the following annual rates:

Land Rights 4% (25 years)
Transformer station equipment 2% - 10% (10 - 50 years)
Distribution station equipment 2.2% - 3.3% (30 - 45 years)
Distribution system 1.7% - 6.7% (15 - 60 years)
Meters 5% – 6.7% (15 - 20 years)
Buildings 1.7% - 2% (50 - 60 years)
Leasehold improvements 33.3% (3 years)
Furniture & Equipment 10% (10 years)
Computer Hardware 20% (5 years)
Computer Software 33.3% (3 years) (3 years)

System Supervisory equipment 6.7% (15 years)
Communication equipment 5% (4 years) (20 years)
Transportation Equipment 5% - 12.5% (8 - 20 years)
Other equipment 10% - 20% (5 - 10 years)

Prior to 2010, full amortization was recorded in the year of acquisition; no amortization is recorded in the year of disposition. Beginning in 2010, half a year of amortization is recorded in the year of acquisition.

- Disposals and Write Downs

For readily identifiable assets retired or disposed of, the asset cost and related accumulated amortization are removed from the applicable capital accounts.
Differences between the proceeds, if any, and the unamortized asset amount plus removal costs are recorded as a gain or loss in the year of disposal.
For grouped assets, the assets and accumulated amortization are removed from the records at the end of their estimated average service life, regardless of actual service life.

- Betterment vs. Repair and Maintenance

The following questions are considered to determine if costs incurred are for betterment of the capital asset or expensed as maintenance and repairs:
Increase in the previously assessed physical output or service capacity? Yes or No.
Lower the associated operating costs? Yes or No.
Substantial improvement in the quality or efficiency of output? (>10%) Yes or No.
Is the life of the asset extended? Yes or No.

Criteria

At least one question must be answered “Yes” to qualify for betterment.

The filing requirements state: *"Per the Board's letter of July 17, 2012, electricity distributors that elected to remain on CGAAP in 2012 must have implemented regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes were mandatory in 2013 for all distributors that had not made these changes, and therefore, all cost of service applications for 2015 rates should reflect that these changes were made in 2012 or 2013."*

NPEI engaged KPMG to assist with determining the level of PP&E componentization required under IFRS, establishing updated useful lives and examining whether any changes to overhead capitalization were required. As a result of this analysis, and accordance with the Board's letter, NPEI implemented accounting changes for depreciation expense on January 1, 2013. NPEI did not implement any accounting changes relating to its capitalization of overhead in 2013, as NPEI determined that its overhead capitalization was already compliant with what is permitted under IFRS. Therefore, the only changes to NPEI's capitalization policy since its last COS Application (EB-2010-0138) relate to useful lives, as follows:

Transformer station equipment: changed from 40 years to 10 - 50 years
Distribution station equipment: changed from 25 years to 30 - 45 years
Distribution system: changed from 25 years to 15 - 60 years
Meters: changed from 25 years to 15 - 20 years
Computer Software: changed from 1 year to 3 years
System Supervisory equipment: changes from 14 years to 15 years
Communication equipment: changed from 4 years to 20 years
Transportation Equipment: changed from 8 years to 8 - 20 years

On July 28, 2009, the Board released the *Report of the Board: Transition to International Financial Reporting Standards (EB-2008-0408)* ("the Board Report"). The Board Report states: *"IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. Utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining the revenue* *requirement. This reclassification is also necessary to preserve continuity of the rate base."* Accordingly, NPEI has included computer software and land rights in PP&E for rate-setting purposes.

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administrative costs that are not directly attributable to as asset, cannot be capitalized under IFRS.

The Board Report requires distributors to adhere to IFRS capitalization accounting requirements for rate-making and regulatory reporting purposes effective January 1, 2013 and that a distributor is required to file its capitalization policy, as part of its first cost of service rate filing after adopting the new policies.

NPEI, along with its consultant KPMG, performed an analysis of all costs that were being capitalized under CGAAP in order to determine whether these costs were eligible for capitalization under IFRS. The analysis conducted by NPEI and KPMG for direct costs is summarized below. The analysis of capitalized overhead is discussed in Exhibit 2, Tab 2, Schedule 3.

<u>Material Cost</u>

These costs include stocked items taken from NPEI's warehouse and issued out to each capital project, as well as direct materials which are purchased and delivered to the job site. These costs represent the purchased price and initial delivery costs of the materials.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in a manner intended by management. Therefore, there will be no impact on the amount of material costs being capitalized under IFRS.

Labour Cost

Capitalized labour includes engineering design time and operations construction time, which are recorded on timesheets. The timesheets capture the nature of the activities undertaken, and time spent on each task by employee.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in a manner intended by management. Therefore, there will be no impact on the amount of labour costs being capitalized under IFRS.

Third Party Cost

Sub-contractor costs are incurred when NPEI engages a third party for the construction of NPEI's assets.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in a manner intended by management. Therefore, there will be no impact on the amount of third party costs being capitalized under IFRS.

Capitalization of Overhead

NPEI, along with its consultant KPMG, performed an analysis of all costs that were being capitalized under CGAAP in order to determine whether these costs were eligible for capitalization under IFRS. As mentioned in Exhibit 2, Tab 2, Schedule 1, NPEI determined that no changes were required to its capitalization of overhead. The analysis conducted by NPEI and KPMG relating to the capitalization of overhead is summarized below.

Benefit Costs

Employee benefit costs include statutory payroll costs (EI, CPP, WSIB, EHT), statutory holidays, vacation, sick and rest time, life insurance, health and dental benefits and pension costs. For each hour of regular time recorded on a timesheet, NPEI adds a benefit percentage to the regular labour costs. This allocates the benefit costs between capital and expense in accordance with how the regular labour is recorded. Under both CGAAP and IFRS, the benefit costs allocated to capital labour are also capitalized, since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. NPEI has determined that there will be no impact on the amount of employee benefit costs being capitalized under IRFS.

Labour Burden

The Filing Requirements state: *"The applicant must identify the burden rates related to the capitalization of costs of self-constructed assets. Furthermore, if the burden rates were changed since the last rebasing application, the applicant must identify the burden rates prior to and after the change."*

NPEI currently uses a burden rate of between 58% and 60%, which is applied to regular labour, in order to capture the benefit costs described above. The burden rate is adjusted periodically based on the actual benefit and labour dollars. The range of burden rates has not changed since NPEI's last rebasing application (EB-2010-0138).

Prior to January 1, 2011, NPEI capitalized a percentage of the stores department and a percentage of the garage department. Also, NPEI included in its overhead burden training expenses. NPEI does not capitalize any portion of management wages nor does it capitalize administration costs or engineering burdens. NPEI only capitalizes direct labour and payroll overhead burdens. NPEI reviewed its capitalization policy with KPMG at the same time componentization and asset useful lives were discussed. Since January 1, 2011, NPEI no longer capitalized any portion of the stores, garage or training expenses. The only portion of OM&A expenses capitalized are employee benefits including CPP, EI, WSIB, EHT, pension, other employee benefits, life insurance, health and dental insurance etc.

Therefore, there will be impact relating to general and administrative burden under IFRS.

Transportation and Fleet Costs

These are costs directly associated with maintaining NPEI's fleet of trucks, vans, trailers and other fleet equipment. Transportation and fleet costs include labour, fuel, repairs, parts and supplies, and all other costs necessary to keep the rolling stock in service. Fleet rates are determined on an annual basis for each vehicle group (bucket truck, pick-up truck, van etc.) by dividing the directly attributable annual costs for each vehicle type by the annual usage in hours. When a vehicle is used for a capital project, the fleet cost is capitalized based on the vehicle type fleet rate multiplied by the hours of usage. Vehicle usage is recorded by NPEI's engineering and operations staff on the same timesheet as labour, in order to ensure proper matching of labour and the associated vehicle costs on the appropriate project.

NPEI anticipates that there will be no significant change in fleet rates and therefore no impact on fleet costs being capitalized under IFRS.

NPEI has completed the Board's Appendix 2-D, which is included at Exhibit 2, Tab 2, Schedule 3, Attachment 1.

Attachment 1 of 1

OEB Appendix 2-DA/DB

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Exhibit:	4
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Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2011 Historical Year**	**2012 Historical Year**	**2013 Historical Year**	**2014 Bridge Year**	**2015 Test Year**
Total wages as per Appendix 2K (T4 earnings for 2011, 2012 and 2013)	$ 9,546,131	$ 10,152,181	$ 10,612,484	$ 10,874,154	$ 11,156,960
Total OM&A Before Capitalization (B)	$ 9,546,131	$ 10,152,181	$ 10,612,484	$ 10,874,154	$ 11,156,960

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2011 Historical Year**	**2012 Historical Year**	**2013 Historical Year**	**2014 Bridge Year**	**2015 Test Year**	**Directly Attributable? (Y/N)**	**anation for Change in Overhead Capita**
employee benefits	$ 4,454,193	$ 4,706,763	$ 5,075,419	$ 4,940,226	$ 4,984,070	Y	NPEI does not have any changes in OH being capitalized
costs of site preparation							
initial delivery and handling costs							
costs of testing whether the asset is functioning properly							
professional fees							
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)							
administration and other general overhead costs							
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 4,454,193	$ 4,706,763	$ 5,075,419	$ 4,940,226	$ 4,984,070		

% of Capitalized OM&A (=A/B)	47%	46%	48%	45%	45%		

Capital Contribution Policy

NPEI collects Contributions in Aid of Capital Expansions and Connections ("Capital Contributions") in compliance with the provisions in the Distribution System Code and NPEI's Conditions of Service. Under CGAAP, capital contributions are recorded in Account 1995 – Contributions and Grants – Credit. NPEI maintains sub-accounts of Account 1595 for each category of distribution system plant for which capital contributions are received (overhead, underground and transformers). Capital contributions are treated as an offset to the gross capital cost of the appropriate category of asset. Accumulated depreciation of capital contributions is an offset to accumulated depreciation of the related category of assets, and depreciation expense on capital contributions is an offset to depreciation expense of the capital assets.

Under IFRS, capital contributions are to be recorded as deferred revenue, and amortized into income over the useful life of the asset to which it relates. The Board Report states: *"IFRS requires customer contributions to be recorded as revenue or as deferred revenue (depending on the circumstances) instead of as an offset to capital cost. For regulatory reporting and rate making purposes the amount of customers contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facility to which it relates. This reclassification is necessary to preserve continuity of the rate base."*

Consistent with the Board Report, NPEI has continued to include forecast 2015 capital contributions as an offset to rate base.

Depreciation Policy

On July 8, 2010, the Board issued a letter to All Licensed Electricity Distributors regarding a depreciation study (undertaken by Kinetrics Inc.) commissioned by the Board to assist electricity distributors in their transition to IFRS ("the Kinetrics Report"). The Board's letter stated: *"The Kinetrics Report provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances. The Board expects distributors to reflect their consideration of the information contained in the Kinetrics Report when they present an IFRS-based rates application to the Board."*

NPEI staff, with the assistance of KPMG, determined the appropriate componentization and typical useful lives for NPEI's assets. NPEI notes that all of its updated useful lives are within the range of minimum and maximum useful lives, as set out in the Kinetrics Report. See the Board's Appendix 2-BB, which is included at Exhibit 4, Tab 4, Schedule 1, Attachment 2.

As discussed in Exhibit 2, Tab 2, Schedule 2, the Board's letter of July 17, 2012, requires electricity distributors that elect to remain on CGAAP to implement the regulatory accounting changes for depreciation expense by January 1, 2013. Accordingly, NPEI implemented its accounting changes for depreciation on January 1, 2013. NPEI has used Account 1576 Accounting Changes for CGAAP to record the impact of implementing the depreciation changes. See Exhibit 9, Tab 3, Schedule 8.

NPEI's Depreciation Policy is included at Exhibit 9, Tab 2, Schedule 5, Attachment 1.

Asset Retirement Policy

As noted in NPEI's Capitalization Policy in Exhibit 2, Tab 2, Schedule 2:

For readily identifiable assets retired or disposed of, the asset cost and related accumulated amortization are removed from the applicable capital accounts. Differences between the proceeds, if any, and the unamortized asset amount plus removal costs are recorded as a gain or loss in the year of disposal.

For grouped assets, the assets and accumulated amortization are removed from the records at the end of their estimated average service life, regardless of actual service life.

Beginning in 2015, NPEI will begin to derecognize grouped assets at the end of their actual service lives, as required under IFRS.

Cost of Eligible Investments for Distributors

NPEI confirms that it has not incurred any costs to make any eligible investments as described in section 79.1 of the OEB Act and O. Reg. 330/09 under the Act. Therefore, NPEI has not completed the Board Appendices 2-FA through 2-FC.

Attachment 1 of 3

OEB Appendix 2-FA

File Number:	EB-2014-0096
Exhibit:	2
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Appendix 2-FA

Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (pg 15, EB-2009-0349)

There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.
Scenario 1: **Past Investments with No Recovery.** The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: **Investments in the Test Year and Beyond.** Distributor plans to make investments in 2015 and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

REI Investments (Direct Benefit at 6%)	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project 1									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0

	2011	2012	2013	2014	2015	2016	2017	2018	2019
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Part B

Expansion Investments (Direct Benefit at 17%)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Project 1									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Attachment 2 of 3

OEB Appendix 2-FB

File Number:	EB-2014-0096
Exhibit:	2
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Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2015 and beyond, enter variables as in the application.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2011			2012			2013		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA			$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt			$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt			$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity			$ -	$ -		$ -	$ -		$ -	$ -
ST Interest			$ -	$ -		$ -	$ -		$ -	$ -
LT Interest			$ -	$ -		$ -	$ -		$ -	$ -
ROE			$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -

	2014			2015 Test Year			2016		
		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -

	2017			2018			2019		
		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2015 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2011		2012		2013		2014		2015	
	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)										
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up										
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Income Tax	2016		2017			2018			2019	
	Direct Benefit	Provincial	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
					Total			Total		
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Taxable income	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Tax Rate (to be entered)										
Income Taxes Payable	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Gross Up										
Income Taxes Payable	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -

Net Fixed Assets		2011	2012	2013	2014	2015	2016	2017	2018	2019
Enter applicable amortization in years:	25									
Opening Gross Fixed Assets			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation		2011	2012	2013	2014	2015	2016	2017	2018	2019
Opening UCC			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Date Filed:September 23, 2014

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OEB Appendix 2-FC

File Number:	EB-2014-0096
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Tab:	2
Schedule:	7
Page:	3
Date:	29-Aug-14

Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2015 and beyond, enter vaiables as in the application.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributors rate base.

		2011			2012			2013			2014		
		Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2015 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2011		2012		2013		2014	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)								
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up								
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets	2011	2012	2013	2014	2015	2016	2017	2018	2019
Enter applicable amortization in years: 25									
Opening Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Capital Additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Additions (half year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2014	2014	2014	2014	2015	2016	2017	2018	2019
Opening UCC			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

2015 TEST YEAR			2016			2017			2018			2019		
Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
		$ -			$ -			$ -			$ -			$ -
		$ -			$ -			$ -			$ -			$ -

2015 TEST YEAR		2016			2017			2018			2019
Direct Benefit	Provincial	Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial
$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -

Addition of ICM Assets to Rate Base

NPEI has not filed an Incremental Capital Module as part of any prior IRM Rate Application. Therefore, NPEI does not have any ICM Assets to incorporate into rate base.

File Number: EB-2014-0096

Date Filed: September 23, 2014

Exhibit 2

Tab 3 of 3

Service Quality and Reliability Performance

Service Quality and Reliability Performance

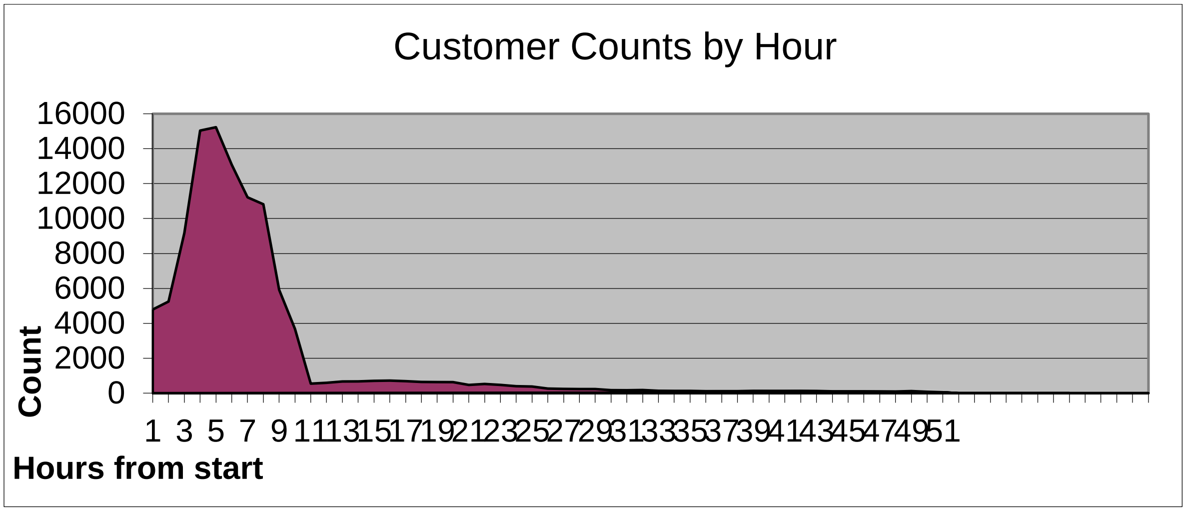
In accordance with Section 7.0 of the Distribution System Code, NPEI annually reports a number of reliability indices and service quality indicators to the Board.

NPEI measures its service reliability using the System Average Interruption Duration Index (“SAIDI”), System Average Interruption Frequency Index (“SAIFI”) and Customer Average Interruption Duration Index (“CAIDI”), which are calculated both on the basis of including loss of supply and excluding loss of supply.

NPEI has completed the Board’s Appendix 2-G, which is included at Exhibit 2, Tab 3, Schedule 1, Attachment 1. For the indicators where NPEI is below the Board’s standard, further details are provided below.

SAIDI and SAIFI

The 2013 trend for NPEI shows a higher than the Average hours of interruption at 5.31 than previously experienced at 1.77-3.19. This can be explained by two incidents of severe weather events that NPEI experienced. The first event was a hot weather event with high winds, torrential rains, and a large amount of lightning starting on Friday night of July 19th, 2013, and crews affecting repairs throughout the weekend with accumulated damage repair costs of $180,423. Below is a graph demonstrating the customers experiencing an outage by Hours elapsed, and a chart with Customer Counts by Feeder during this event.

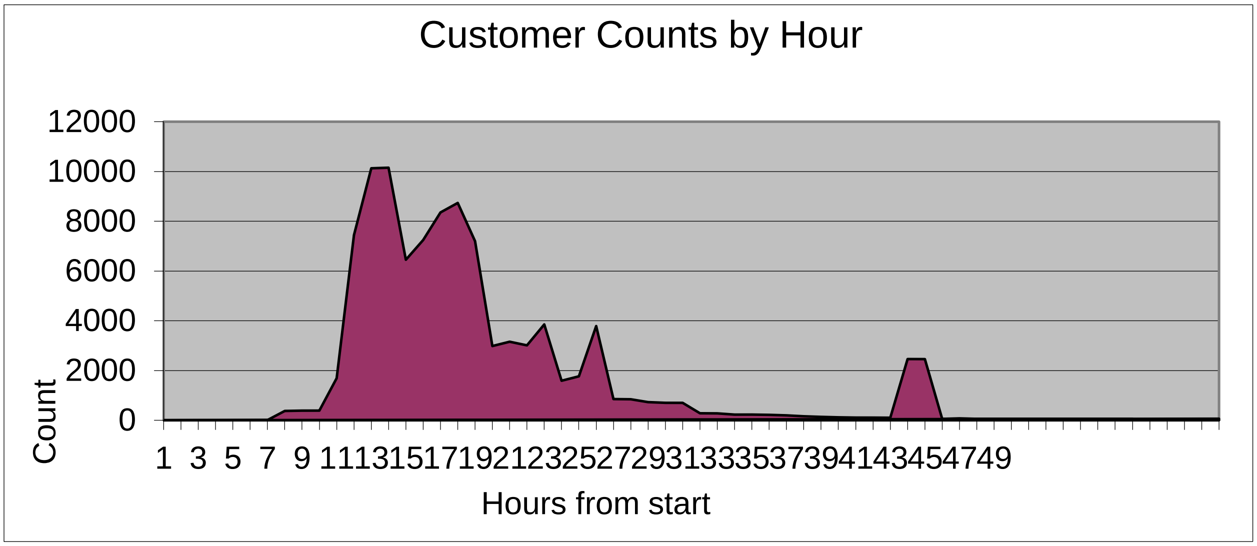


July 19, 2013 Storm - Customer Outage Report

FEEDER	COUNTS
18M1	4758
18M2	2471
18M4	63
Niagara West 2	2383
Niagara West 5	1260
Vineland F1	1768
Vineland F2	1901
12M33	1880
Total	**16484**

The second severe weather event was a cold weather Ice Event which most of Southern Ontario experienced on December 22, 2013. Below is a graph demonstrating the number of

Customers experiencing an outage by hours elapsed during the event, followed by a chart showing smart meters reporting outage within the NPEI OMS.



SMART METER ALARMS

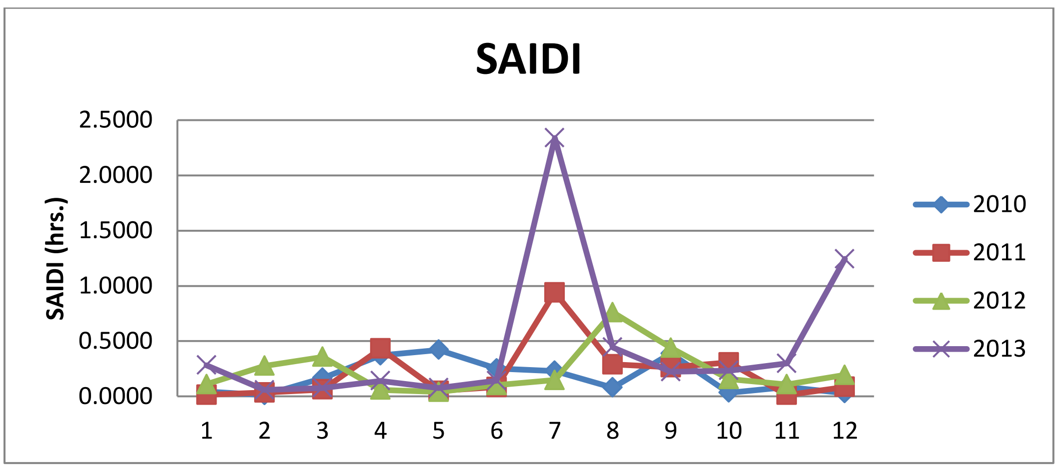
DAY	CALL COUNT
12/21/2013	165
12/22/2013	9461
12/23/2013	789
12/24/2013	115
12/25/2013	14
12/26/2013	8
12/27/2013	2

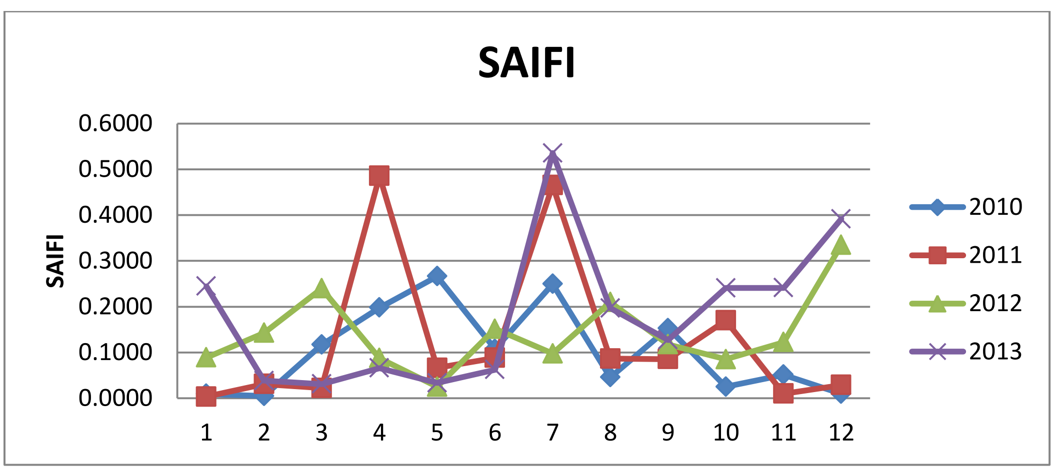
The following two charts demonstrate the Historical SAIDI & SAIFI illustrating the trends between 2010 & 2013. The **System Average Interruption Duration Index (SAIDI)** is commonly used as a reliability indicator by electric power utilities. SAIDI is the average outage duration for each customer served.

$$\text{SAIDI} = \frac{\text{sum of all customer interruption durations}}{\text{total number of customers served}}$$

The System Average Interruption Frequency Index (SAIFI) is commonly used as a reliability indicator by electric power utilities. SAIFI is the average number of interruptions that a customer would experience.

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$





By studying the 2013 data in each graph, it is possible to see the effect of the two weather events on the statistics. But the data for other years without events out of NPEI's control, demonstrates that NPEI's statistics are well within acceptable limits, based upon industry standards.

Low Voltage Connections

The 2013 trend for NPEI shows a lower than the 90% Industry Average, at 79.20% attributed to a change in process for servicing new Subdivision Lots within the service area. In the spirit of efficiency & cost effectiveness, NPEI had partnered with Enbridge Gas, who had a Field Crew dedicated to supplying a common trench and duct installation service, from the Service Lead to the meter-base, while they installed the Gas Service. A common stepped trench was excavated, in which the electrical conduit and gas pipe were installed. A coordinated effort between both companies ensured that Line-staff from NPEI were present to install & splice the secondary conductor, and roll out the CATV & Bell Drops, while the Enbridge Crews tapped into the Gas Main and connected the meter. Upon completion the Enbridge Crew performed backfill services of the Trench. The economy of scale realized included, a single call from the Homebuilder to arrange for the provision of servicing from both Utilities upon receipt of appropriate approvals, a single agency arranging locate services for the common trench, a single backhoe and trench for excavation and restoration of both Utilities, a flat rate fee paid by NPEI to Enbridge for the service provision passed through to the builder, and fewer service lead damage claims.

In 2013 Enbridge elected to have a Contractor provide Service Lead installation on their behalf, and deploy their own Crews to other Operations. The new Contractor did not include the services formerly supplied to NPEI within their scope. Until NPEI could negotiate with the Enbridge Contractor to supply these services, new Residential Services needed to be installed and connected. An Electrical Contractor was hired to perform this work on NPEI's behalf, but due to a duplication of efforts, the process was no longer as efficient as previously experienced. Both Contractors could not be on site at the same time, causing delays. Coordinating locates became difficult due to a lack of information dissemination between agencies for services installed to the locate provider. Service lead damage claims increased, due to smaller lot sizes making the installation of two separate trenches, while maintaining safe equipment clearance from installed plant difficult, further complicating and delaying service connection.

After several negotiations, NPEI and the Enbridge Contractor were able to reach an agreement for service provision. A cost structure was agreed to, Documentation for Equipment Inspections, Insurance, and Safety Training were reviewed, the Contractor had Staff Members attend a training course offered by the IHSA to certify secondary splicing competence. Homebuilders were notified that the Enbridge Contractor would now be supplying the service previously afforded by Enbridge and the process to follow. With the Contractor Staff trained to perform secondary splices, NPEI Crews no longer needed to attend the site until the meter install and connection at the transformer was required. This will further streamline the process for service connections, and the statistics should reflect these changes in 2014.

Attachment 1 of 1

OEB Appendix 2-G

File Number:	EB-2014-0096
Exhibit:	2
Tab:	3
Schedule:	1
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Date:	29-Aug-14

Appendix 2-G
Service Reliability Indicators
2009 - 2013

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2009	2010	2011	2012	2013	2009	2010	2011	2012	2013
SAIDI	2.671	2.105	2.580	2.750	5.560	2.671	1.775	2.580	2.310	5.310
SAIFI	1.118	1.231	1.540	1.700	2.210	2.389	1.672	1.680	1.880	2.740

5 Year Historical Average

		Includes outages caused by loss of supply		Excludes outages caused by loss of supply
SAIDI		3.133		2.929
SAIFI		1.560		2.072

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2009	2010	2011	2012	2013
Low Voltage Connections	90.0%	87.9%	84.7%	81.7%	89.3%	79.2%
High Voltage Connections	90.0%	90.0%	85.7%	93.3%	94.0%	90.0%
Telephone Accessibility	65.0%	61.0%	41.5%	70.3%	76.1%	80.7%
Appointments Met	90.0%	100.0%	100.0%	83.2%	99.6%	96.2%
Written Response to Enquires	80.0%	99.8%	81.5%	98.4%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	92.2%	86.7%
Emergency Rural Response	80.0%	92.9%	100.0%	100.0%	84.0%	82.1%
Telephone Call Abandon Rate	10.0%	3.6%	13.9%	1.8%	3.9%	1.4%
Appointment Scheduling	90.0%	100.0%	100.0%	100.0%	99.6%	100.0%
Rescheduling a Missed Appointment	100.0%	n/a	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	n/a	n/a	100.0%	88.1%	100.0%